



Next-Generation Geothermal Energy

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Authors



Stan Miranda
Founder & CEO

- Partners Capital Chief Executive (2001-2020)
- Evolution Global Partners (Venture Capital)
- Bain & Company Director
- Harvard MBA



Jack Haynes
Head of Investments

- Strategy Consultant, Bain & Company
- Investment Banking, Citibank & Canaccord Genuity
- INSEAD MBA



Tristan Varakuta
Investment Associate

- Consultant, L.E.K Consulting
- Oxford BA

This publication was produced by the True North Institute in collaboration with members of the All Aboard Coalition and with input from a broad range of geothermal energy experts, including senior executives from leading next-generation geothermal companies. The All Aboard Coalition represents 17 of the world's most respected energy transition venture capital and private equity firms, united by a shared commitment to accelerating the deployment of transformative clean energy technologies.

This research was undertaken for the benefit of Coalition members and the broader energy investment community to help build greater consensus around the technologies and early-stage companies most likely to lead the emergence of next-generation geothermal as a scalable source of firm, 24/7, carbon-free power. By identifying the most promising pathways and market leaders, we hope this work will help focus capital and industry support behind the companies best positioned to accelerate commercialization and scale this critical new source of clean energy.



Right: Fervo Energy's Cape Station project in Utah





Dear Reader

This whitepaper's purpose is to increase investors' insights into the development of what could be a major new source of firm, 24/7 carbon-free power in the US and other parts of the world. Our purpose for producing it is to give us enough confidence to invest in this sector, as it has its challenges. It is a deep understanding of these challenges that arms us with our own investment strategy for the sector.

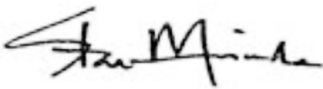
As we are the furthest thing from geothermal engineers, we draw all of our conclusions from others. The key inputs include approximately 40 research reports from different academics and the DoE, NREL, McKinsey, Bain, IRENA, and CATF. It also benefits from our due diligence undertaken on 12 early to growth stage next generation geothermal companies which included their third-party technology due diligence reports. Finally, our interactions with fellow venture investors have given us helpful insights into the sector. The output has been reviewed by the CEOs of 5 of these companies. We have been careful not to divulge proprietary information, but our conclusions are informed by these.

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The detail is in here for True North. We require it before investing. For everyone else who picks this up, I would recommend reading the 16-page Executive Summary and selectively dive in on specific issues in the chapters which follow.

We will have missed many things. But we write these whitepapers as they are excellent at "drawing fire" from the true experts. So, fire away.

Ever onward,

A handwritten signature in black ink, appearing to read "Stan Miranda". The signature is fluid and cursive, with the first name "Stan" being more prominent than the last name "Miranda".

Stan Miranda

Founder and CEO of the True North Institute

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Executive Summary

A widely cited study by the Massachusetts Institute of Technology estimates that the global geothermal resource accessible with next-generation technologies exceeds 10,000 GW—roughly equivalent to today’s total installed global electricity capacity and nearly half of total global primary energy capacity. Yet geothermal currently provides only ~17 GW of electricity worldwide, representing approximately 0.3% of annual generation. This disparity exists because conventional geothermal development has historically been limited to rare naturally occurring hydrothermal reservoirs. Next-generation geothermal technologies are poised to expand the industry’s addressable resource base fivefold by 2035, enabling economically viable access to vast subsurface heat resources previously beyond reach.

Next-Generation Geothermal (NGG) technologies — principally Enhanced Geothermal Systems (EGS) and Advanced Geothermal Systems (AGS) — aim to remove these geological constraints by engineering geothermal reservoirs or closed-loop systems in a far broader range of locations. The IEA’s most optimistic scenario (2024 Future of Geothermal Energy, low-cost case) projects over 800 GW by 2050 if technology costs and policy environments align. TNI’s more conservative central case, which assumes slower permitting reform and supply-chain scale-up, forecasts 80 GW by 2035 and 220 GW by 2050. Even under this lower trajectory, the industry could expand from roughly \$10B of annual revenue today to \$100–130B by 2050, creating a meaningful new clean infrastructure asset class, though not one large enough to fundamentally reshape the global energy mix.

The key uncertainty is around the economic interaction with different geological heat gradients around the world. TNI estimates EGS LCOE can decline from roughly ~\$90/MWh today to ~\$55/MWh by 2035 through three identifiable drivers: larger project scale reducing fixed costs (~\$14/MWh benefit), drilling and reservoir-performance improvements (~\$10/MWh), and lower cost of capital as projects mature into bankable infrastructure assets (~\$11/MWh). However, the success of the NGG technology (mostly EGS) is highly geography/geology dependent on three key well engineering risks:

1. water loss,

2. heat dissipation and
3. well restimulation.

We discuss each of these risks in the technology chapter 5.

Additionally, economic outcomes will depend on successfully navigating three key execution challenges:

1. Management, workforce, and capital resource constraints will determine the pace and efficiency of development.
2. Drilling capacity — particularly rig availability — will dictate how quickly operations can scale.
3. Grid interconnection timelines will govern when projects are able to begin generating revenue.

We paint scenarios for these execution challenges in the cost chapter 7.

The most competitive outcomes are likely in regions with exceptional thermal gradients — particularly the Western United States — while Europe’s lower geothermal gradients make unsubsidised EGS-for-power materially more difficult. We therefore expect Europe to lead primarily in geothermal heat and combined heat and power (CHP) applications and to lag the US by 5–10 years in commercial NGG power economics.

The climate impact of this deployment remains modest relative to wind, solar, EVs and batteries, but still meaningful. TNI estimates NGG deployment could avoid

250–350 Mt CO₂ per year by 2035, rising to 700–900 Mt CO₂ per year by 2050 as geothermal displaces marginal fossil fuel generation. At the upper end, this represents roughly 1.5% of current global greenhouse gas emissions measured in CO₂e.

The natural long-term owners of geothermal assets are likely to be the oil & gas majors. These firms possess the subsurface expertise, drilling capability, project management experience and balance sheets required to scale the industry. However, most remain cautious given geothermal’s complexity, relatively small addressable market, and lower returns compared to hydrocarbons. Innovation is therefore currently being driven by entrepreneurial teams — often founded by former oil & gas engineers — supported by venture capital and strategic investors such as Ormat Technologies. This creates a clear role for financial investors to fund the early-stage de-risking phase before assets transition to lower-cost infrastructure or public-market capital.

Today, roughly 80 venture-backed companies are pursuing the NGG opportunity, though capital remains insufficient to bring the sector to bankable scale. We identify three primary investment approaches, each with a distinct risk-return profile:

- (1) direct investment in geothermal developers;
- (2) investment in “picks & shovels” enabling technologies — including AI-driven subsurface characterisation, advanced drilling systems, high-temperature downhole electronics and non-hydraulic stimulation — which benefit regardless of which developers ultimately succeed; and

- (3) participation in the “first 10%” of project development, particularly drilling and reservoir creation, where the majority of project de-risking and value creation occurs.

A deep understanding of this sector is increasingly important for investors. The leading next-generation geothermal company, Fervo Energy, recently went public at a \$7.6B valuation, signalling to the broader investment community that geothermal energy has moved beyond theoretical promise into a category with credible commercial momentum. We also recognize the risks that can accompany highly valued climate-tech IPOs; several earlier entrants to the sector struggled under the weight of inflated expectations, damaging both investor confidence and, in some cases, the long-term perception of their markets.

That said, capital matters profoundly in infrastructure-scale energy transitions. We believe the approximately \$1.9B raised through Fervo’s IPO provides the company with the resources needed to accelerate deployment, expand technological leadership, and help catalyse broader industry growth. If execution matches ambition, geothermal energy has the potential to evolve into a \$100+B global industry and become a meaningful pillar of the long-term energy transition.

The Market Opportunity

Geothermal resources can be used to produce either heat or electricity. This paper focuses exclusively on geothermal electricity generation – worldwide. These are our main conclusions.

Geothermal may well be one of the biggest beneficiaries of the “energy transition reset” taking place at present as the pendulum swings away from the ambitious, policy supported corporate and household decarbonisation targets set since the Paris Agreement was signed in 2016. The hardest climate technologies that were clearly dependent upon policy support (subsidies, taxation, regulation) including clean hydrogen, carbon capture, biofuels and many industrial decarbonisation technologies, are struggling today to attract capital as these businesses can no longer be underwritten with green premiums in their cash flow models. Climate technologies that can compete against incumbent fossil fuel alternatives on a stand-alone basis and/or continue to have policy backing, are attracting more capital today. Geothermal is

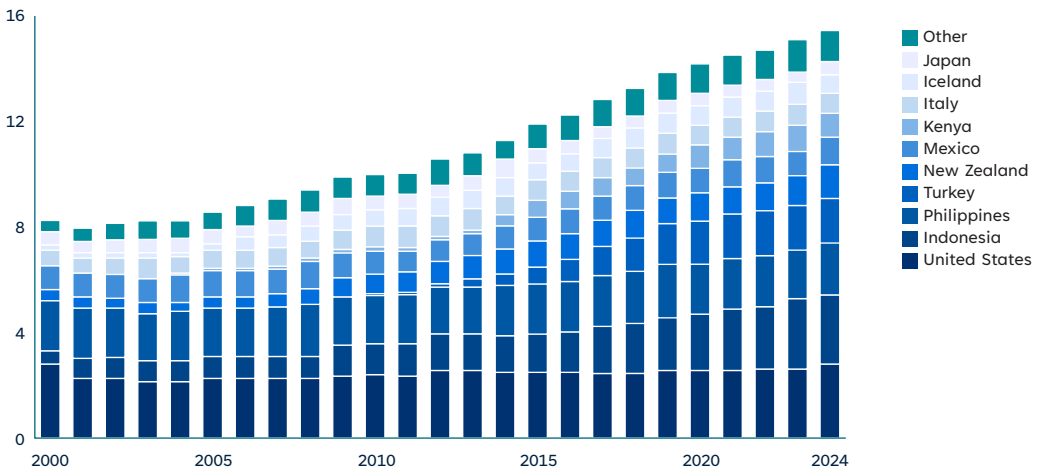
one of those. Finally, geothermal appears to fall in the “purple” category in the US to the extent that both Republicans and Democrats are helping to accelerate permitting, while Democrats continue to block fossil fuel permits and Republicans block wind and solar permits.

The traditional geothermal industry is largely tapped out. Geothermal heat generated electricity has existed for 122 years, since 1904. Global installed traditional geothermal power capacity stands at approximately 17 GW, generating around 99 TWh annually and implying a current revenue pool of approximately \$9–10B at prevailing wholesale prices. This represents approximately 0.2% of the estimated 9,000 GW of global electricity capacity. Geothermal capacity growth has averaged 1.2% per year between 2022 and 2024, against 9.7% annual growth in total global installed power capacity. A small presence of geothermal power in the world is only becoming progressively diluted within an expanding global power mix. Traditional geothermal potential is capped by the near-full exploitation of suitable geothermal sites.

Exhibit 1

Global geothermal capacity growth has largely plateaued since 2018. The U.S. and Indonesia together account for ~30% of total global geothermal output, with Europe largely absent.

Global geothermal capacity by country
Capacity in GW



Source: IRENA Renewable Energy Statistics 2025, processed by Our World in Data.

Note:

Figures refer to installed nameplate capacity; actual operational capacity in the US is approximately 3.9 GW per US Geothermal Energy Association estimates, with the delta representing permitted but non-operating plants and capacity degradation at legacy sites including The Geysers.

Conventional geothermal is expected to continue growing slowly and reliably, but nearly all forecasts (IEA, US EIA, and IRENA) for geothermal becoming a material global power source depend on next-generation technologies unlocking deeper and more geographically widespread resources. But the combination of AI-driven subsurface modelling and machine learning applied to reservoir prediction is already expanding the set of economically discoverable hydrothermal resources. We could see traditional geothermal expanding by a multiple (e.g. 2x) but not by an order of magnitude (not 10x as we are expecting from NGG). AI applied to vastly improved seismic imaging, distributed fibre sensing, satellite/geospatial datasets, better temperature gradient mapping and oil & gas drilling databases creates this 2x+ possibility. Certainly, the management team of Zanskar (AI-based siting) are counting on this source of TAM growth.

So the practical ceiling for “traditional” geothermal is likely higher than historical estimates implied—not because the Earth suddenly contains more hydrothermal systems, but because we are getting much better at finding hidden or marginally economic reservoirs that were previously invisible or too risky to drill. This is particularly important in sedimentary basins, “blind” geothermal systems without surface manifestations and lower-permeability systems that can be modestly enhanced without full EGS stimulation. Companies like Ignis Energy and Zanskar are explicitly pursuing this thesis using AI-enabled exploration and oil & gas subsurface workflows.

The key limitation remains that traditional geothermal still requires the coincidence of heat, permeability and fluid pathways.

Next-Generation Geothermal technologies include any means of circumventing the cap on traditional geothermal through technologies such as enhanced geothermal systems (EGS) which deploys fracking in deeper, hotter and harder geological sites, geopressured geothermal systems (GGS), which harness the thermal energy and hydraulic pressure of deep sedimentary basins, Advanced Closed-Loop (ACL) and Super-Hot Rock (SHR). These technologies have the potential to expand the viable resource base well beyond conventional hydrothermal reservoirs creating a geothermal power industry ~13x the current size by 2050.

TNI projects global geothermal power capacity will reach 80 GW by 2035 and 220 GW by 2050 in our base case.

All figures refer exclusively to electricity generation capacity and exclude heat. Delivering this build-out requires cumulative capital investment of approximately \$350B by 2035 and \$1.1T by 2050, implying annual deployment of roughly \$35B per year through 2035, accelerating thereafter. At an 80% capacity factor and PPA prices of \$65–85/MWh, this translates to an annual global revenue pool of \$35–45B by 2035 and \$100–130B by 2050, with geothermal’s share of global electricity generation rising from approximately 0.3% today to 1.2% by 2035 and 2.7% by 2050. TNI estimates this deployment avoids 250–350 Mt CO₂ per year by 2035, rising to 700–900 Mt CO₂ per year by 2050 as geothermal displaces the marginal fossil fuel generation mix. For 2050, this substitution accounts for a reduction of around 1.5% of current global greenhouse gas emissions measured in CO₂e.

Our base case scenario assumes that the strategic importance of baseload domestic power generation to national competitiveness in the global AI race, sees significant improvements in permitting and a highly supportive government policy environment in those nations where the geothermal opportunity is greatest. This is far from certain. Without that support, we

expect capital invested in geothermal will be constrained and oil & gas majors will continue to sit on the sidelines longer. In this “low case scenario”, we would expect to see deployment 5–10 years behind our central path. This implies 50 GW by 2035 and 150–180 GW by 2050, broadly consistent with the integrated assessment modelling of van der Zwaan & Dalla Longa (2019), which projects 100–150 GW by 2050. Even in this low case, capacity triples by 2035 from today’s 17 GW, but revenue pools shrink to roughly \$25–30B by 2035 and \$60–80B by 2050 and exit windows for venture and growth investors are compressed.

Our central projection for European geothermal of 8 GW by 2035 and 20 GW by 2050 (10% of the 2035 total, 9% in 2050) faces the structural challenge that European subsurface gradients are typically 20–30°C/km versus 45–60°C/km in the Western US, which materially constrains EGS-for-power economics. We discuss the regional sensitivity in detail in Chapter 4.

Next-Generation Geothermal (NGG) is still at a very early stage of development with only four companies generating revenue: Fervo, Eavor, Zanskar (AI-driven exploration to identify conventional hydrothermal) and Sage (currently generating revenue from geothermal energy storage, with first power generation targeted for late 2027). There are 80 venture backed geothermal start-up companies listed in the PitchBook private equity database, with just ~\$5B of venture capital invested in those 80 companies. Fervo and Eavor account for 60% of this and are clearly in the lead from a pure cumulative invested capital perspective.

Next-Generation Geothermal development is hard, really hard, even for veteran oil and gas operating executives. Four structural differences from oil and gas economics matter most.

First, NGG is more capital-intensive upfront. An oil and gas project drills one producing well. A geothermal project requires at least

two, a producer and an injector, plus a dedicated power plant above ground. Total project capex is therefore roughly 4x what a comparable oil and gas well would cost. Second, we need massive multi-well platforms with large power plants to make the economics work. To scale at a pace that creates a meaningfully large business in a profitable time frame, management teams need to manage multiple rigs over multiple sites at the same time over many years. 1 GW data centres are being built and potentially supplied from geothermal. Powering a 1 GW data centre entirely from geothermal would require approximately 100–250 wells depending on per-well productivity. Fervo’s stated metric is approximately 100 MW of generating capacity added per rig-year, implying that a four-rig drilling programme operating continuously could in principle add 2 GW over five years. Fervo has indicated it can scale from running two rigs simultaneously to at least five, equivalent to adding ~0.5 GW per year.

Rig access, however, is less binding than commonly assumed. The U.S. land rig fleet currently includes ~400–500 idle (‘stacked’) rigs that could be reactivated at 20–30 per month, and the technical labour pool — particularly veterans of the unconventional shale era — is already migrating into NGG developer teams in meaningful numbers. The binding constraint is therefore less the absolute supply of rigs or people and more whether NGG developers can offer competitive economics to retain them against incumbent oil & gas demand.

Thirdly, the cash flows arrive on a fundamentally different timetable. Shale wells recoup full capital cost in 6–18 months from initial production. Larger, longer-cycle projects like deepwater offshore and oil sands are much longer-cycle, with 8–15 year paybacks but still benefit from front-loaded peak production. A geothermal project, by contrast, recoups on a flat-line PPA basis across a 30-year asset life with no production peak — every barrel-equivalent of energy is contracted at the same price for the full asset life. Revenue per well is also capped at 7.5–10

MW, bounded by the local heat gradient and the share of heat that can be captured (the enthalpy ratio). Together, this means NGG cannot rely on one lucky well. It requires many wells drilled reliably and repeatably to generate the cumulative cash flow that justifies the upfront capital.

The flip side is meaningful for investors. Once a field has demonstrated stability and signed an investment-grade PPA, the cash flow is contracted, fuel-free and predictable for 20+ years, the profile of an infrastructure asset, not an E&P asset. This matters for exit valuation: infrastructure assets trade at materially higher cash-flow multiples than oil and gas producers, because market risk is low (though technology and subsurface risk remains material during development). The same project therefore attracts a different, and deeper, pool of capital at exit than anything in the oil and gas universe.

Finally, the deeper structural difference is that oil and gas has uncapped commodity upside, currently visible in real time as geopolitical events drive price volatility, which compensates for project risk. Geothermal under long-term PPAs has capped revenue, which both reduces risk for off-takers and limits how much upside can compensate for development risk for the developer. This dynamic only becomes neutral if subsurface and execution risk are addressed earlier in the project lifecycle, which is one reason the “first 10%” de-risking strategy is structurally attractive for early-stage capital.

The Technology

Next-Generation Geothermal encompasses four primary technologies: Enhanced Geothermal Systems (EGS), Geopressured Geothermal Systems (GGS), Advanced Closed-Loop (ACL), and Super-Hot Rock (SHR). Each is designed to overcome the geological constraints that have historically limited geothermal to a small fraction of global energy supply.

EGS creates artificial reservoirs by hydraulically stimulating (fracking) hot, impermeable rock, enabling scalable geothermal development wherever sufficient heat exists.

GGS leverages naturally high-pressure, fluid-filled sedimentary formations, offering both power generation and long-duration energy storage but requiring a rare combination of pressure, temperature, and permeability.

ACL systems circulate fluid through sealed underground loops, eliminating water loss and seismicity risks but delivering lower power density due to reliance on conductive heat transfer.

SHR targets supercritical resources (>374°C) with the potential for dramatically higher output per well. Whether breakthrough drilling is required for SHR depends largely on depth: high-gradient volcanic sites, The Geysers, Larderello, Iceland, Imperial Valley, and Newberry Volcano (where Mazama Energy recorded 331°C with conventional drilling in 2025), can reach near-supercritical temperatures within ~5 km using existing equipment. The harder constraint on SHR is the Brittle-Ductile Transition zone where drilling goes from fracturing hard brittle rock to rocks deforming plastically and permeability becomes much harder to maintain (fractures close quickly). This zone sits at 3-6 km in volcanic regions and >10 km in normal continental crust and registers temperatures of 350°C to 500°C. Below this zone, developers need advanced closed-loop heat-conductive architectures rather than EGS-style stimulation.

Among these, **EGS is emerging as the most credible pathway to scale.** It combines access to higher-temperature resources with engineering repeatability, drawing directly on proven oil and gas techniques such as horizontal drilling and hydraulic stimulation. This enables learning-curve cost reductions and increasing output per well, positioning EGS as the most likely route to utility-scale, firm, low-carbon power in the near to medium term. While developers

will ultimately select technologies based on site-specific geology, EGS uniquely expands the addressable resource base and provides a practical bridge from today's conventional geothermal systems to a more scalable future.

However, these economics are highly geography dependent and are overshadowed by the three key engineering risks of EGS: water loss, heat dissipation and well restimulation remain uncertain. We discuss each of these risks in the technology chapter.

Water loss / recapture risk: Fervo's early operating data suggests current EGS systems can recapture roughly 70% of injected water under steady-state conditions, with the remainder largely staying within the reservoir as pressure support rather than being permanently lost. While improved well designs may eventually push recapture rates above 99%, water loss remains one of the core technical and economic risks for EGS because poorly behaved fracture systems can materially impair project performance.

Heat dissipation / thermal drawdown risk: Recent reservoir modelling suggests many current EGS well designs may rely heavily on near-well thermal drawdown rather than fully sustainable long-term heat replenishment, particularly where well spacing and reservoir sweep areas are limited. Achieving truly sustainable 30-year output may require materially longer laterals, wider spacing and higher upfront drilling costs, leaving uncertainty around whether future systems can consistently hit targeted power costs.

Well longevity / restimulation risk: Fervo's initial operating record is encouraging, but the industry still lacks long-duration evidence showing how engineered fracture systems perform over 20–25 year project lives. Investors therefore likely need to assume periodic re-drilling, re-stimulation and make-up wells as part of normal lifecycle costs, although falling drilling costs could help offset the economic impact if replacement frequency proves manageable. Other technical well engineering approaches

will play important but more targeted roles—GGs in specific sedimentary basins or storage applications, ACL in jurisdictions sensitive to seismicity or water use (which makes ACL particularly relevant in Europe, Japan and other geographies where hydraulic stimulation faces regulatory or social-licence constraints), and SHR as a longer-term, high-upside frontier.

EGS's structural advantage is most pronounced in the US and Canada, where the existing shale supply chain — drilling rigs, completion crews, frac spreads, water management — translates directly to EGS economics. Outside North America (and to a lesser extent Argentina), this supply-chain advantage is materially weaker, and the playing field across NGG technologies is more level, particularly in Europe, where seismicity sensitivity and the absence of a deep frac-services market may favour ACL or hybrid approaches over pure EGS. EGS sets the benchmark for whether Next-Generation Geothermal can become a material contributor to global energy systems.

Over the long term, leading Next-Generation Geothermal developers may evolve toward a portfolio-based, 'horses for courses' approach — building capabilities across multiple NGG technologies and matching the technology to the geology of each specific site. In the near and medium term, however, we expect the opposite. Most developers will remain specialised in a single technology where they are building depth of experience with a given technology, with "fast followers" such as AlterG coming in close behind Fervo, entering now that Fervo has proven EGS's viability. Incumbent conventional geothermal operators (Ormat, Calpine, Cyrq) may play this same game of coming in with EGS first, but are likely to layer multiple NGG technologies on top of their existing hydrothermal portfolios as each technology matures.

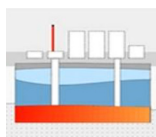
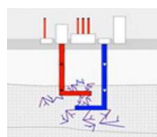
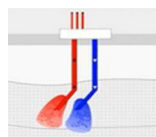
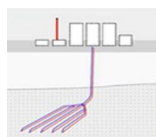
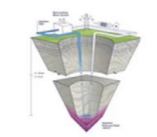
Investors should not view Super-Hot Rock (SHR) as competing for the same capital pool as other Next-Generation Geothermal technologies, as it sits

at a fundamentally earlier stage of development with a distinctly different risk–return profile. While EGS, GGS and ACL are progressing through demonstration toward commercial deployment, SHR remains at a prototype stage (TRL ~4–5) and depends on the successful maturation of entirely new ultra-high-temperature drilling systems and materials. At the same time, SHR offers the highest theoretical upside in the sector: by accessing supercritical resources at depths typically >5 km and

temperatures above 374°C, it could deliver 5–10× more energy per well than EGS, materially increasing power density and long-term economics. As such, SHR should be understood less as a near-term competitor to EGS and more as a longer-horizon, high-risk, high-reward frontier technology—one that sits on a different part of the development curve and is appropriately funded by investors seeking asymmetric returns rather than near-term, scalable deployment.

Exhibit 2

EGS appears to win out over all Next-Generation Geothermal technologies, but other technologies will suit certain geological circumstances better than EGS

Aspect	Conventional (Hydrothermal Reservoir Dependent)	Enhanced Geothermal Systems (EGS)	Geopressed Geothermal System (GGS)	Advanced-Closed Loop (ACL)	Super-Hot Rock (SHR)
Technology	Taps naturally hot, pressurised, and permeable reservoirs to generate heat and power.	Engineered flow paths between wells, allowing fluid circulation without natural permeability.	“Huff-and-Puff” method injects fluid into fractures, heats in place, then recovers it.	Advanced Closed-Loop system circulates a working fluid to extract heat without reservoir interaction.	Taps ultra-high temperatures, typically at greater depths, for exponentially greater power.
Image					
Leading Developers	Ormat, Enel Green Power, Calpine	Fervo Energy	Sage Geosystems	Eavor, XGS Energy, GreenFire Energy	Mazama Energy Quaise

Source: TNI analysis

We remain cautious on investments in SHR companies and technologies partly based on the long history of research and development in this area not realising the envisioned developments. The scientific roots for SHR start in the 1970s and the modern commercialisation wave started in 2011 when AltaRock concluded at Newberry Volcano in Oregon that conventional EGS

temperatures were probably not economically sufficient and higher-temperature systems near the brittle-ductile transition were likely necessary for commercial-scale economics. In 2021, AltaRock, now part of the AltaRock / Blade joint venture trading as Mazama, announced the start of development of the first Super-Hot Rock geothermal resource at Newberry. In 2018, Carlos Araque founded

Quaise Energy as an MIT spinout with the ambition to build the first Super-Hot Rock geothermal power plant. Eight years on, the current target is 2030 for the first commercial operating SHR power plant in central Oregon, also at Newberry.

Risk varies meaningfully across the NGG technologies, and investors should be careful not to treat the NGG category as monolithic. EGS-first developers like Fervo carry stimulation and reservoir-connectivity risk. ACL developers like Eavor still need to demonstrate directional drilling at scale across the multi-kilometre laterals their economics depend on. AI-driven explorers like Zanskar need to validate that their hit rates hold up at scale, with delivery on flagship projects like Big Blind being the proof point.

The Costs

In most developed power markets, natural gas effectively sets the marginal price of baseload electricity, making it the relevant benchmark against which geothermal must compete. Because gas-fired generation costs are dominated by fuel, this benchmark is not static. The implied clearing price of electricity moves directly with gas prices. Competitiveness for geothermal is therefore not defined by undercutting gas at a single point in time, but by achieving an LCOE that holds across the range of gas price outcomes observed over a cycle. In practice, this implies a required LCOE of approximately \$60–70/MWh in the US and \$120–130/MWh in Europe, reflecting the structurally higher and more volatile gas price environment in Europe.

The good news is that EGS and other NGG technologies can achieve cost competitiveness through three primary and quantifiable drivers. First, plant

scaling from early 50 MW projects to 200 MW utility-scale developments reduces LCOE by ~\$14/MWh through spreading of fixed development, EPC and operating costs. Modular, factory-built power-plant units, for example Ormat’s binary “OEC” skids, which can be installed in 5–20 MW increments, accelerate this cost-reduction trajectory in the near term. They are particularly useful because they are designed to work efficiently across a wide range of resource temperatures (typically 110–230°C), not just the very hottest “high-enthalpy” wells, so they can be deployed at the broader population of next-generation geothermal sites that produce useful but not exceptional reservoir temperatures. Because each unit is a standardised piece of equipment, developers can commission the first 10–20 MW of a 200 MW field as soon as the first cluster of wells is drilled, rather than waiting for the entire wellfield to be complete before building one large bespoke power plant. This phased approach generates subsurface and plant-performance data earlier, shortens the time to first revenue, and gives investors a meaningful Stage-Gate decision point before the bulk of project capex is committed.

Second, continued improvements in drilling performance, including higher site success rates, gains in drilling speed, and access to higher-temperature resources, all contributing to a further ~\$10/MWh reduction.

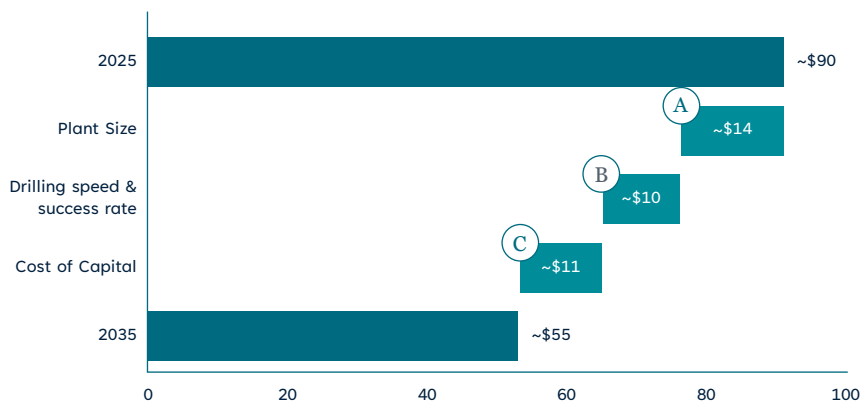
Third, as projects demonstrate repeatable performance and transition to levered project finance structures, the weighted average cost of capital (WACC) declines from ~9% to ~6%, reducing LCOE by an additional ~\$11/MWh. Together, these mechanisms drive the modelled reduction in EGS costs from ~\$90/MWh today to ~\$55/MWh by 2035.

Exhibit 3

Scale, drilling gains and reduced weighted average cost of capital (WACC) drive EGS LCOE from ~\$90 to ~\$55/MWh by 2035

Forecast reduction in EGS LCOE

USD / MWh



Source: TNI analysis

Notes:

(A) Plant size (~\$14/MWh): Scaling from 50 MW (8 wells) to 200 MW (~25–30 wells) dilutes fixed EPC, interconnection and development costs across larger generation capacity.

(B) Drilling speed & success rate (~\$10/MWh): Higher well success rates (74% to 83%), rising bottom-hole temperatures (toward ~320°C) and RoP gains (520 to 1,200 ft/day) reduce wellfield capital intensity per productive well.

(C) Cost of capital (~\$11/MWh): WACC declines from ~9% (construction-phase, equity-heavy) to ~6% (mature, levered project finance) as subsurface risk is retired and projects become bankable.

The EGS cost model is based on bottom-up well-by-well economics: drilling cost built from depth, RoP, non-productive time, rig rates, stimulation cost and dry hole probability. Well performance assumptions anchored to latest Fervo Energy disclosures where available; triangulated with peer-reviewed literature where Fervo data is not yet public. U.S. federal ITC and constant annual production decline assumed across all scenarios. Outputs shown as project-level LCOE (\$/MWh).

The bad news is that the deployable NGG opportunity is shaped by the intersection of three constraints, all of which are location or geography dependent: 1) Subsurface geology

still defines where Next-Generation Geothermal can work; 2) drilling capacity (rig availability) determines how fast it can scale; 3) grid interconnection governs when it can earn revenue.

In practice, the \$90-to-\$55/MWh LCOE trajectory is most likely to be achieved first in the western United States by the early-to-mid 2030s, where gradients exceed 45°C/km, oilfield drilling rigs can be redeployed, and some transmission capacity already exists to reach load centres. Europe and other international markets are likely to lag by 5–10 years due to the absence of a domestic drilling rig fleet and longer permitting cycles. Our central-case projection of 80 GW by 2035 reflects this reality. 80 GW is a large number in absolute terms but a tiny fraction of the theoretical base, underscoring how much of the opportunity remains blocked by drilling cost and electricity grid build-out.

Of that 80 GW global target, approximately 40 GW is in the United States. Achieving 40 GW of US geothermal capacity by 2035 requires drilling an average of 360 wells per year at 10 MW per well; roughly a 4x increase in US geothermal drilling activity within a

decade. For context, this is well within the scale of precedent set by US shale gas, which expanded from fewer than 1,000 horizontal wells per year in 2005 to over 10,000 by 2012 as the economics proved out.

Geological siting quality and early lease control are emerging as primary sources of durable competitive advantage in Next-Generation Geothermal power. The Bureau of Land Management (BLM) administers geothermal leasing across 245 million acres of public land in the western United States, the vast majority of which remains unleased. As NGG commercial viability is validated, this acreage is already being repriced: average BLM lease prices rose 282% in 2025 to \$127/acre, and for the first time every parcel offered was sold. The first-mover advantage on acreage is now materially valuable: Fervo's April 2026 S-1 discloses an average lease cost of approximately \$4/acre across its ~595,900-acre portfolio — assembled before the market repriced — versus recent BLM auction clearing prices of \$344–\$410/acre, an 80–100x cost gap captured by a single first-mover. Developers who combine superior subsurface characterisation with disciplined acreage acquisition today can secure a cost and productivity advantage that is difficult for later entrants to replicate. The window to execute that strategy at low cost is narrowing rapidly.

Next-Generation Geothermal will be financed through the “usual” staged transition from high-risk, equity-funded exploration to low-cost, debt-financed infrastructure. Next-Generation Geothermal technologies face the classic “missing middle” investment challenges where the venture capital backers do not write checks of the size needed to prove the technology at commercial scale and growth equity and infrastructure investors balk at the technology risk behind large investments. This points to the need for syndication across VCs and growth equity investors to spread the risk of progressive subsurface derisking. This is what has happened to date for Fervo, Zanskar and Sage, as examples. As their projects demonstrate well performance and

secure contracted revenues, they become bankable and can access non-recourse project finance and, ultimately, infrastructure capital. The pace at which this transition occurs will determine both the scalability of the sector and the extent of LCOE reduction.

The Competition

The scale of the global geothermal business will ultimately be driven by the strategies of oil & gas majors. A large, long-established oil major is precisely the sort of organisation that has the resources and skills to manage scaling Next-Generation Geothermal projects. By “oil & gas majors” we are thinking mostly of ExxonMobil, Shell, BP, Chevron, TotalEnergies, Eni and ConocoPhillips. The national oil companies and other independents are less likely to enter or drive major investment.

The shale revolution was recent enough that the muscle memory remains in place for EGS. This is less true for ACL, GGS and SHR, where the engineering challenges are different and the read-across from shale is weaker; outside EGS, the technology playing field is more level across operator types. The obstacle to oil & gas majors entering Next-Generation Geothermal at scale is not the technology; it is opportunity cost. Majors today are still seeing 25–30% IRRs in their core upstream portfolios, with a renewed wave of US shale productivity gains and Permian basin extensions putting more, not less, capital to work in conventional fossil fuel development. Geothermal IRRs of 10–15%, even after costs move down the curve five years from now, simply cannot compete inside a major's capital allocation framework while the alternative is north of 25%. Geothermal entry is therefore best understood as a timing question. Majors will move when their existing oil and gas inventory runs down, or when geothermal IRRs rise to within striking distance of upstream returns. This is consistent with the shale playbook itself: ExxonMobil did not build XTO; it acquired XTO in 2010, more than a decade after Mitchell Energy

proved the technology, and only once shale economics had been validated by independent operators.

At today's EGS costs (~\$90/MWh), drilling geothermal wells does not yet match natural-gas-fired generation on a pure NPV basis, primarily because of the timing of cash flows — shale gas realises 70% of well revenue in the first five years, whereas geothermal produces at a flat rate across a 30-year asset life. However, as Chapter 7 demonstrates, the \$90 to \$55/MWh cost trajectory driven by scale, drilling productivity and cost of capital brings EGS firmly into competitive range with gas-fired power by the early 2030s. It is worth acknowledging that large CCGT projects are typically hedged or sold under fixed-price contracts that deliver low-volatility returns to off-takers, so NGG's competitive set in the near term is not merchant natural gas but other forms of baseload clean firm power — nuclear SMRs, long-duration storage and carbon-captured gas. Two further factors accelerate the crossover. First, if the world is focused on clean firm power, geothermal wins as soon as carbon capture costs are applied to natural gas. Second, the picture inverts where heat — rather than electricity — is the primary offtake: a geothermal well delivering ~10 MW-th of heat displaces ~10 MW-th of gas burn directly, whereas the same well converts only ~2 MW-e of electricity. In Europe — where gas is structurally more expensive, district heating is widespread and CO₂ prices are explicit — geothermal-for-heat (and combined heat-and-power) is therefore the more compelling proposition, and we expect heat-led applications to remain a relevant secondary revenue stream even for projects whose primary focus is power generation.

In the medium to long term, returns for NGG will be driven primarily by the demand for clean firm energy. If there is a 'green premium' (or 'domestic source' premium more relevant to Europe and Asia) to be paid relative to fossil fuel generated electricity, this could close the IRR gap. Two further structural advantages narrow the LCOE comparison versus wind and solar over the project life: (i) cascading use of

high-temperature resources, where power generation is followed by district heating, greenhouse and aquaculture revenue (particularly relevant in Europe and parts of Asia); and (ii) a 70–90% capacity factor over 20–25 year PPAs, three to four times higher than solar PV (~25%) and roughly twice that of onshore wind (~35%), materially compressing the lifetime \$/MWh delivered relative to intermittent renewables that are bid into the same PPA prices.

The Investment Opportunities

We see three alternative strategies for investing in Next-Generation Geothermal: 1) investing directly in developers, 2) investing in the enabling technologies or “picks & shovels” companies; and 3) investing in developers focused on the early derisking phase – what we call the “first 10%.”

Strategy #1: Investing Directly in NGG Developers

Investing directly in Next-Generation Geothermal (NGG) developers is likely the highest-risk strategy. NGG developers will face significant scaling constraints, competing for rigs, talent and capital against both oil & gas majors and established hydrothermal players with far larger balance sheets and existing operating platforms. Unlike software businesses, geothermal benefits primarily from regional rather than global scale economies, suggesting a fragmented industry structure rather than a winner-takes-all outcome. Over time, we expect developers to become increasingly technology-agnostic, deploying the most suitable NGG approach for each basin rather than adhering to a single technical architecture.

The greatest strategic risk is that incumbents such as Ormat Technologies and oil & gas majors including Shell, Chevron and BP allow venture-backed firms to absorb the early technology and reservoir risk before entering later with superior resources and lower-cost capital. This dynamic mirrors the history of US shale gas. The majors largely entered

shale through acquisition rather than organic development — most notably ExxonMobil’s \$41B acquisition of XTO Energy in 2010 — after early independents had already demonstrated commercial viability. Early movers who secured high-quality acreage and proved repeatable well economics generated substantial value; later entrants often overpaid for leases and struggled to earn acceptable returns.

We expect a similar pattern in NGG. The long-term industry leaders are likely to be integrated geothermal developers and oil & gas majors, while only a small number of today’s venture-backed NGG developers are likely to survive to premium exits. The most attractive developer investments will therefore be those able to demonstrate repeatable drilling economics, secure high-

quality land positions and build strategic partnerships with likely future acquirers. The investment case is less about owning a perpetual standalone compounder and more about funding early-stage technology and reservoir de-risking ahead of an IPO or strategic sale.

Timing is critical. Returns will depend heavily on entering before the technology is fully de-risked and exiting as incumbent interest accelerates. If geothermal project returns remain materially below oil & gas returns, the acquisition window may open more slowly than expected, extending holding periods and compressing venture returns. Of the three NGG investment approaches discussed in this report, direct developer exposure carries the highest risk and widest dispersion of outcomes.

Exhibit 4

Fervo Cape Station geothermal EGS site



Source: Fervo Energy Press Release

Among current developers, private companies Zanskar and Sage Geosystems appear among the most compelling based on their progress in demonstrating commercially credible drilling and reservoir performance. Fervo, of course, is the most attractive developer to own, but public valuations will dictate our investment interest.

Strategy #2: Enabling Technologies or “Picks & Shovels”

The “picks & shovels” strategy offers a differentiated risk profile because these companies benefit from industry capex regardless of which geothermal developer or technical architecture ultimately wins. The

most important enabling technologies include AI-driven subsurface characterisation and siting, advanced drilling and rock destruction, high-temperature downhole electronics and measurement, and non-hydraulic stimulation technologies.

This segment is attractive because many of the technical bottlenecks in NGG are already well defined. Most conventional downhole electronics fail above $\sim 175^{\circ}\text{C}$, well below the $300\text{--}400^{\circ}\text{C}$ conditions targeted by advanced geothermal wells, while hard crystalline rock materially increases bit wear and drilling costs. Any technology that demonstrably lowers drilling costs, improves well reliability or reduces rig downtime can capture durable margins across the broader developer ecosystem.






Unlike direct developer investments, picks-and-shovels businesses diversify exposure across the industry and offer clearer acquisition pathways through established oilfield services firms such as SLB, Halliburton and Baker Hughes. Of the “Big Three”, Baker Hughes currently has the strongest geothermal presence, partly driven by demand for its turbine business, while SLB and Halliburton remain comparatively underweight — creating both a near-term competitive opportunity for specialists and a longer-term acquisition catalyst.

However, two caveats are important. First, the geothermal tools market alone is unlikely to reach the scale achieved by shale oilfield services. Geothermal well budgets are structurally smaller, and many high-temperature wells have historically been drilled using modified conventional oilfield tools. The most attractive businesses are therefore likely to be dual-use technologies applicable across geothermal, oil & gas, mining or other deep-drilling industries, rather than firms dependent solely on NGG capex. Second, picks-and-shovels providers do not capture the underlying subsurface value — land, resource ownership and de-risked reservoir upside — that accrues to successful developers.

The most compelling companies in this category typically share three characteristics: (1) technology applicable to adjacent markets beyond geothermal, helping de-risk early revenues; (2) strategic partnerships with drilling contractors or oilfield services incumbents that provide validation and potential exit pathways; and (3) solutions to immediate operational bottlenecks, such as electronics survivability, drilling speed or stimulation efficiency, rather than hypothetical future problems.

Exhibit 5

Examples of promising “Picks & Shovels” companies

Company	“Picks & Shovels” sub-sector	Description
	Power Plant Innovations	US company building factory-made, containerised modular power plants with proprietary turbomachinery purpose-engineered for geothermal-range temperatures, compressing conventional 12–24-month plant build schedules into weeks and materially improving project IRRs.
	Novel Rock Destruction	Slovak deep-tech company commercialising plasma-based drilling (PLASMABIT) that disintegrates rock contactlessly, enabling faster and cheaper access to deep geothermal resources beyond the reach of conventional rotary drill bits.
	Downhole Electronics & Measurement	US developer of extreme-environment downhole sensors and electronics currently rated to 210°C (targeting 300°C by 2030), providing the real-time subsurface data critical for characterising and managing Next-Generation Geothermal reservoirs.
	Stimulation & Completion	US company offering proprietary Electrical Reservoir Stimulation (ERS) technology that creates permeability without hydraulic fracturing, reducing water use, induced seismicity risk, and environmental opposition.
	Geological Characterisation & Siting	US geothermal developer using proprietary AI/ML-driven exploration to identify and de-risk subsurface resources with an 80%+ discovery hit rate, and transitioning into direct ownership and operation of geothermal sites.

The shale analogy is again instructive. Some of the most durable value in shale accrued not to E&P operators but to the integrated service and equipment providers supporting industry-wide drilling growth. We expect a similar dynamic in NGG. As geothermal drilling scales from hundreds to potentially thousands of wells annually, validated enabling technologies should become natural acquisition targets for the major oilfield services firms. For this reason, we view picks-and-shovels strategies as offering the most attractive overall risk-adjusted exposure to NGG growth, with the small scale of the market opportunity being the greatest general concern.

A related opportunity worth investigating is the potential for corporate carve-outs. Several of the most relevant specialist technologies, particularly in power conversion equipment, downhole tooling and specialist well services, currently sit inside larger industrial conglomerates where they are non-core to the parent and compete for capital against larger strategic priorities. As NGG demand scales, carving such businesses out and capitalising them as standalone entities could unlock value that the parent is unlikely to extract on its own.

Strategy #3: The “First 10%” De-Risking Strategy

The “first 10%” strategy focuses on funding the earliest and highest-risk stages of geothermal development — pre-survey work, siting, test drilling and subsurface characterisation — before exiting to developers or infrastructure investors who finance and construct the full project. Although these stages represent only ~10% of total project capex, they embed the majority of the geological risk: confirming temperature gradients, permeability, flow rates and reservoir connectivity. Once a resource is successfully proven, the asset can transition rapidly from speculative exploration to a financeable infrastructure project, often with a substantial uplift in value.

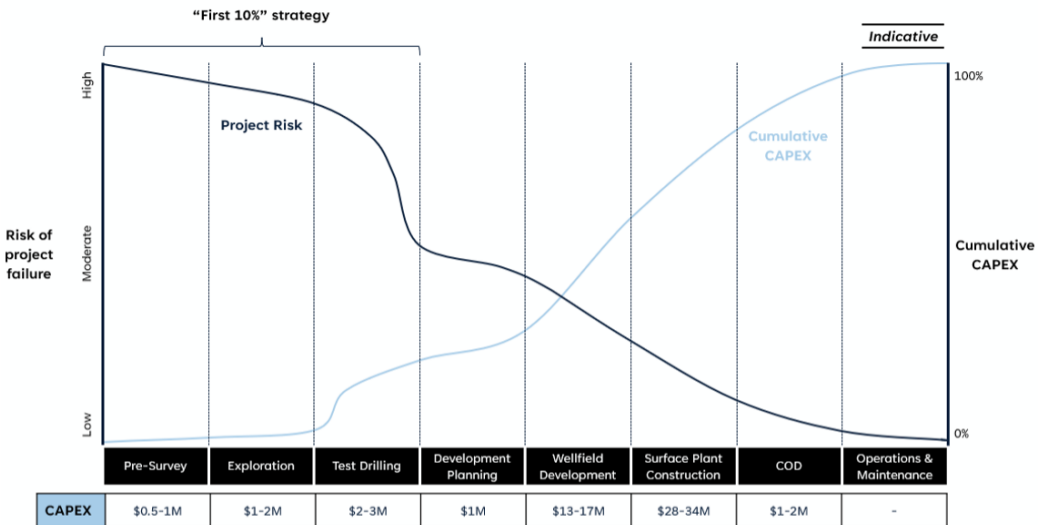
This strategy can be combined effectively with a proactive land-banking model: acquire prospective acreage early, de-risk

the subsurface through targeted drilling and characterisation, then sell or partner the project forward. The attraction is that investors can exit before the most capital-intensive and operationally complex phase of development, where multi-well execution, rig availability, platform construction and long-duration project management become the key constraints.

Exhibit 6 illustrates this concept schematically. In a representative ~\$50M NGG well development programme, the first three de-risking stages may require only ~\$5M of capital but determine whether the broader project is commercially viable. As AI-driven geological characterisation and exploration tools improve, the probability of drilling success should increase, potentially making “shovel-ready” geothermal projects a repeatable asset class for sale to lower-cost-capital developers and infrastructure investors.

Exhibit 6

The “first 10%” strategy in Next-Generation Geothermal focused on the pre-survey to test drilling stages which account for approximately 10% of the total project capex, but embeds the highest risk stages of development



Source: Ignis Energy; alfa8; TNI Analysis

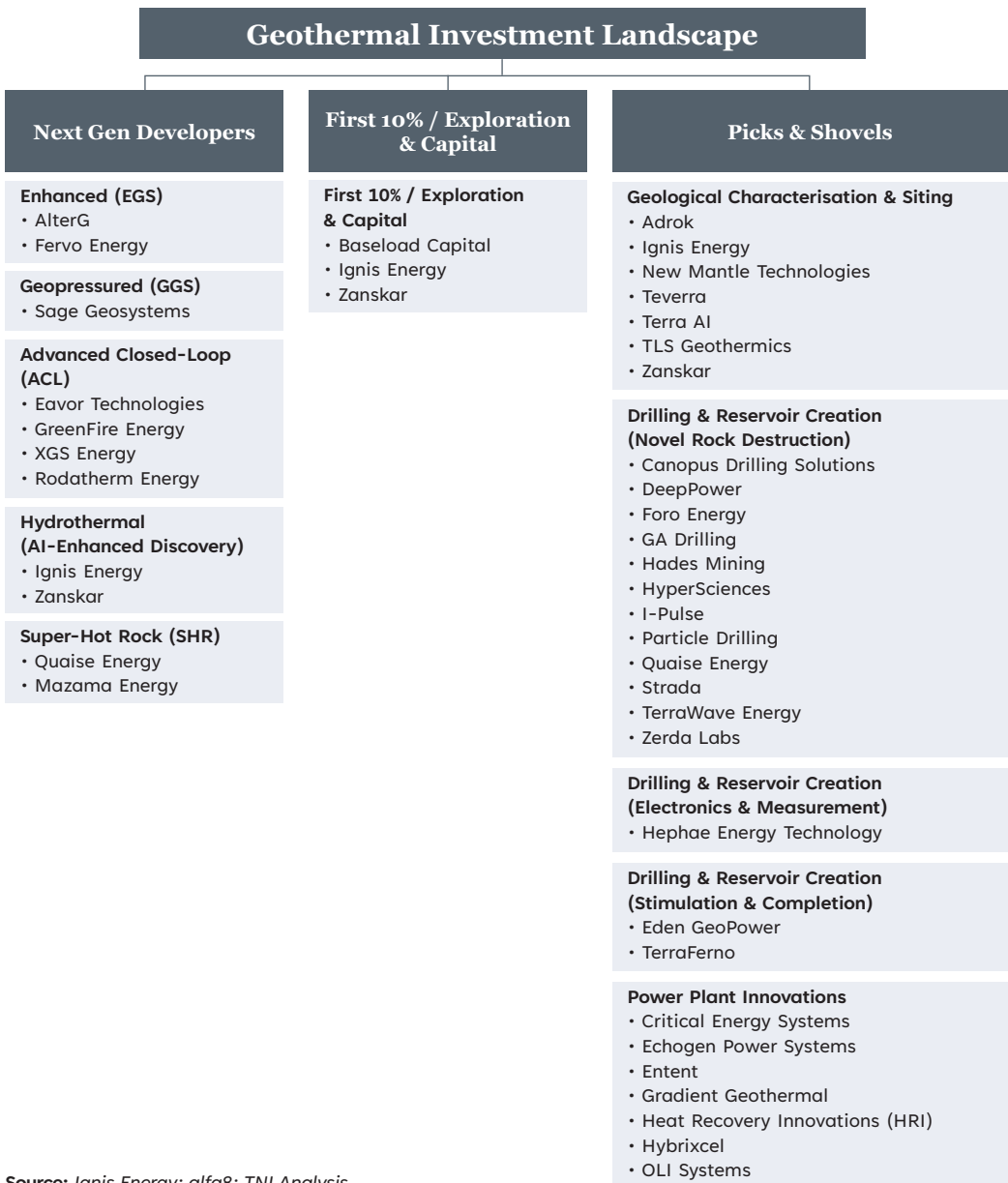
Zanskar may ultimately evolve toward aspects of this model, while Ignis Energy and AlterG are already pursuing variants of the strategy within conventional hydrothermal geothermal. Importantly, these companies are not simply “fast followers” of Fervo Energy. Fervo’s model is centred on engineered EGS reservoir creation in tight hot rock, whereas

Ignis primarily targets naturally productive hydrothermal systems and deploys EGS selectively where basin conditions justify it.

Each of these three NGG investment strategies is profiled below with specific named company examples.

Exhibit 7

Three Next-Generation Geothermal investment strategies



Source: Ignis Energy; alfa8; TNI Analysis

The highlights of the full whitepaper to follow include the detail behind the market sizing, the path of likely cost reduction that drives the market growth, technology comparisons,

the role of land leases in the winning strategy, where oil majors are today with geothermal, and profiles of the leading NGG companies available for your investment capital.

2. Global Geothermal Market Defined

Geothermal resources can be used to produce either heat or electricity. This paper focuses exclusively on geothermal power generation. Geothermal heat and ground-source heat pump (GSHP) systems are excluded from the market definition and all sizing throughout.

Geothermal energy can be segmented into three distinct end-use categories, each operating at different depths, temperatures and scales: (i) geothermal power generation, (ii) direct-use geothermal heat, and (iii) shallow ground-source heat pumps. In aggregate, these reached approximately 5 exajoules (EJ) in 2023, or about 0.8% of global energy demand (or approximately 290 GW of capacity as shown in Exhibit 8 below). Electricity accounts for just over 20% of this total (IEA, 2024), with heat and cooling comprising the remainder. These are discretely different markets, with limited overlap in technology, economics or investment relevance.

Geothermal power generation draws on high-temperature hydrothermal or engineered reservoirs, typically above 150°C and at depths of 3 km or more, to produce grid-connected electricity. Global installed capacity in 2025 was ~17 GW, generating around 99 TWh annually, equivalent to about 0.2% of global electricity capacity, 0.3% of global electricity supply and just over 1% of renewable generation. At wholesale prices of ~\$90-100/MWh, this implies an annual revenue pool of ~\$9-10B.

While geothermal's global share is small, its role is systemically important where resources exist. In markets such as Kenya, Iceland, El Salvador and New Zealand, geothermal supplies more than 10% of total electricity demand, demonstrating its ability to anchor a national grid. This is driven by its defining characteristic, firm and dispatchable output with empirical capacity factors of 70–90% across the operating geothermal fleet, producing four to five times more energy per unit of installed capacity than solar PV. As power systems decarbonise, this reliability

becomes increasingly valuable.

Next-Generation Geothermal power (“NGG power”) refers to technologies that extend this model beyond naturally occurring hydrothermal resources. Through approaches such as Enhanced Geothermal Systems (EGS) and advanced drilling, NGG power seeks to replicate hydrothermal conditions across a much broader set of geographies, materially expanding the addressable market for geothermal power as we quantify in the next chapter.

Geothermal heat (direct use) refers to thermal applications drawing on deeper hydrothermal resources, typically at around 1 km in depth and 60 to 200°C. Together with ground source heat pumps (GSHPs), heat applications account for approximately 79% of global geothermal final energy consumption, split broadly between district heating and building-level heating systems. The market is highly geographically concentrated. The top ten countries account for approximately 90% of global use, with China alone representing nearly half of total consumption and the majority of district heating. Despite its scale in select geographies, direct-use heat is not relevant to the core investment thesis for two reasons. First, the lower temperatures and shallower depths provide limited application of Next-Generation Geothermal technology which benefits from depths of 3 km or more and temperatures above 150°C. Second, the need for local demand, typically within 5 to 10 km, constrains scalability.

China's dominance in direct thermal applications is driven by aggressive national policies aimed at decarbonising district heating networks and reducing urban air

pollution. Geothermal expansion is heavily concentrated in China’s Eastern and Northern provinces, supported by deployment targets outlined in the country’s 13th and 14th Five-Year Plans. This growth is materialising in major urban centres and industrial hubs; for instance, China has successfully developed “smoke-free cities” such as Xiong’an (within the Xiong’an special economic zone) and Rongcheng in Hebei Province, which utilise 100% clean geothermal district heating.

In parts of Europe, Next-Generation Geothermal projects are being developed with integrated heat offtake, where district heating provides a secondary revenue stream alongside power. For example, Eavor’s Geretsried project in Bavaria combines ~8 MWe of power with ~64 MWth of heat, with similar heat-led structures in Hanover and Tilburg. These projects demonstrate how co-located heat demand can improve early

project economics and support deployment in established district heating markets. This illustrates that we cannot completely ignore and separate geothermal heat from our investment evaluation of geothermal power generation.

Ground-source heat pumps (GSHPs)

operate at depths of less than 100 metres and temperatures of approximately 10 to 15°C. They function as shallow heat exchangers, transferring ambient ground heat to and from buildings rather than extracting a geothermal resource. As a result, they require minimal drilling complexity and have no relevance to subsurface resource development at depth. As you can see from Exhibit 8, GSHPs account for the largest proportion of geothermal energy. However, GSHPs are excluded entirely from this analysis, and their output is not included in any capacity or generation figures presented.

Exhibit 8

Total Global Geothermal Energy Capacity – All Three Types of Geothermal Energy

Types of Geothermal Energy	2025 Est. Global Capacity GW	Notes
Geothermal electricity	17	0.2% of global electricity capacity
Geothermal heat (direct-use only, district heating, C&I)	28	mostly China, Iceland and France
Total deep geothermal energy (electricity + direct heat)	45	0.22% of global energy capacity
Geothermal heat (incl. ground source heat pumps)	250 (200 to 300)	mostly residential 50-100metre deep heat exchangers
Total Geothermal Energy (all 3 of above)	290	1.5% of global energy capacity
Total Electricity Capacity	9,000	OurWorldinData.org
Total Energy Capacity	20,000	OurWorldinData.org

Source: TNI Analysis

Global geothermal capacity is poised to grow much more in heat applications than in electricity, with geothermal heat (currently on the order of ~200-300 GWth including heat pumps) having the potential to expand by hundreds of gigawatts as countries electrify buildings and deploy district heating, while geothermal electricity (currently 17 GW) could grow to tens or possibly over a hundred gigawatts if next-generation technologies succeed; the difference reflects both scale and maturity—heat is already economic and expanding due to policy support, urban heating demand, and highly efficient ground-source heat pumps, whereas electricity growth is being newly enabled by advances

in enhanced geothermal systems (EGS), Advanced Closed-Loop (ACL) and Super-Hot Rock (SHR) drilling techniques that aim to unlock deep, high-temperature resources almost anywhere, transforming geothermal from a geographically limited resource into a potentially scalable source of firm, 24/7 clean power.

As our focus is on technology investments, the focus of this paper is purely on the opportunity for technology-driven geothermal power generation. We will not address the more mature technology behind geothermal heat and ground source heat pumps.

3. Current Size of the Geothermal Power Market

Global installed geothermal power capacity stands at approximately 17 GW, generating around 99 TWh annually and implying a current revenue pool of approximately \$9–10B at prevailing wholesale prices. Despite growing interest in next-generation technologies, capacity growth has decelerated sharply, averaging just 1.2% per year between 2022 and 2024, against 9.7% annual growth in total global installed power capacity. A small presence of geothermal power in the world is only becoming progressively diluted within an expanding global power mix.

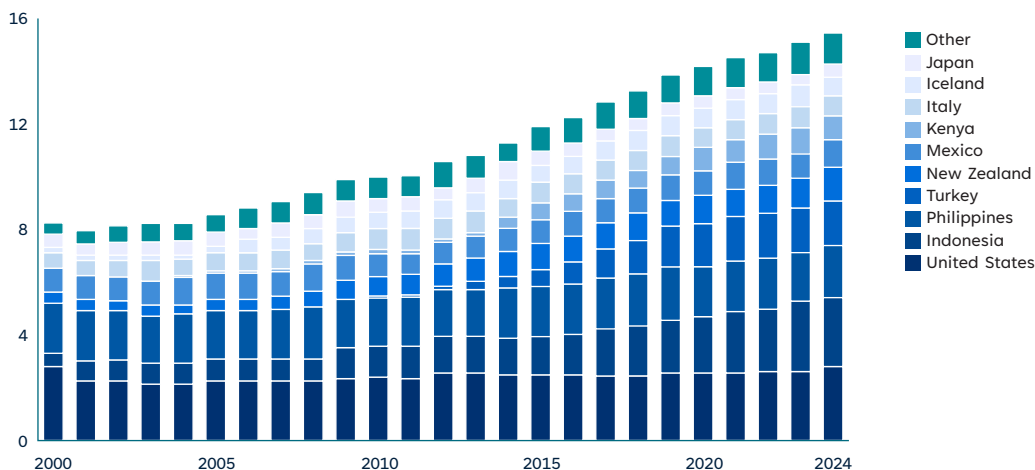
Global installed geothermal power capacity of approximately 17 GW is derived entirely from conventional hydrothermal systems and has changed little since 2018. Output of 99 TWh in 2024 represents just 0.3% of global electricity supply, less than 5% of

solar generation. Capacity growth averaged approximately 4% annually through the 2010s before slowing materially to 1.2% between 2022 and 2024, a period in which total global power capacity expanded at nearly 10% per year.

Exhibit 9

Global geothermal capacity growth has largely plateaued since 2018. The U.S. and Indonesia together account for ~30% of total global geothermal output, with Europe largely absent

Global geothermal capacity by country
Capacity in GW



Source: IRENA (2025)

Geothermal power benefits from exceptionally high-capacity factors of 70–90%, producing four to five times more energy per unit of installed capacity than a comparable solar PV plant. This firm,

dispatchable output profile is a defining commercial characteristic but has not been sufficient to drive capacity growth at scale given the high upfront capital requirement and geographic constraints of conventional

hydrothermal resources.

Despite its long operating history, geothermal remains a small industrial activity in drilling terms. As of 2024, a total of 3,700 geothermal power production wells are in operation today around the world. (Gutierrez-Negrin, 2024). This compares to approximately 2,000,000 oil and gas wells drilled globally since 2000. Approximately 180 geothermal power production wells were drilled annually

between 2015 and 2020 (Rystad Energy, 2021), with activity exceeding 200 wells per year post-2021 and potentially approach ~500 wells in 2025 alone as project pipelines convert into drilling campaigns in the face of increasing firm clean energy demand. Recent activity is concentrated in established hydrothermal markets, particularly Indonesia, Philippines, Türkiye and New Zealand, alongside steady drilling in the United States.

Exhibit 10

Tauhara geothermal power station, New Zealand (184 MW), commissioned in 2024 and supplying ~3.5% of New Zealand's electricity



Source: Contact Energy

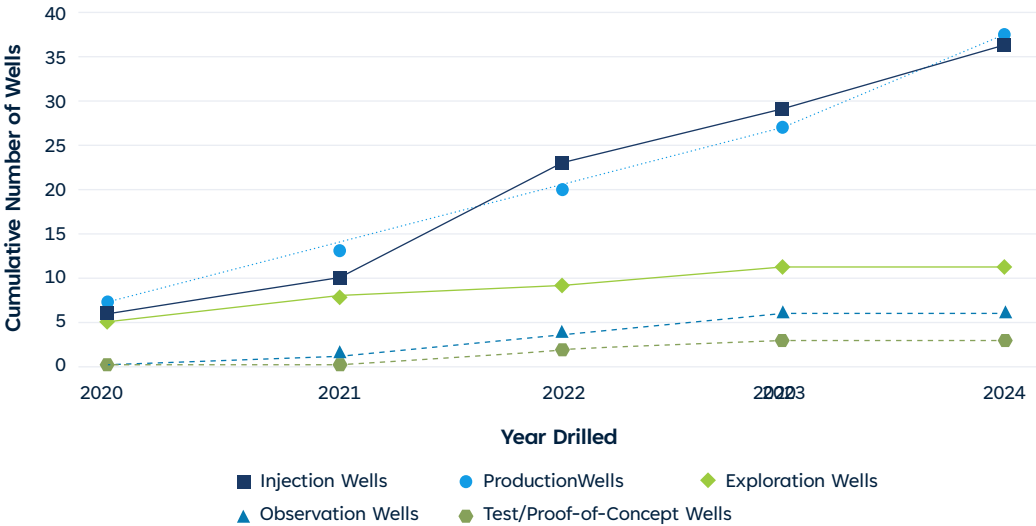
In the United States, 87 geothermal wells for power generation were drilled or spudded (initiated) between early 2020 and September 2024, averaging 21 per year (NREL, 2025). Wells were split broadly evenly between production and injection categories, consistent with capacity additions at established hydrothermal sites rather than

greenfield exploration, which has remained modest throughout the period. Activity is led by established operators such as Ormat Technologies, alongside a small number of next-generation developers, most notably Fervo Energy, whose Cape Station EGS project in Utah accounts for a material share of recent well count growth.

Exhibit 11

Cumulative US geothermal wells drilled or spudded by type, 2020 to September 2024. Total of 87 wells across all categories equates to 21 per year. Production and injection wells account for the majority

Geothermal wells drilled in the US, by year



Source: NREL (2025)

An ambitious new hydrothermal developer engaging in a novel approach is Controlled Thermal Resources (CTR), which was founded in 2012 in California and is developing the Hell’s Kitchen project in the Salton Sea geothermal region. Unlike next-generation geothermal companies focused on EGS or closed-loop systems, CTR’s geothermal resource base is fundamentally conventional hydrothermal geothermal, relying on naturally hot, permeable brine reservoirs that have supported geothermal power generation in the Salton Sea for decades. CTR’s innovation lies not in reservoir engineering, but in integrating geothermal electricity production with direct lithium extraction (DLE) from geothermal brines. The company’s closed-

loop process produces geothermal power while simultaneously extracting battery-grade lithium chemicals before reinjecting the brine underground, positioning the project as both a renewable energy asset and a strategic domestic critical minerals supplier. This hybrid model has attracted significant interest from automakers including General Motors and Stellantis, reflecting growing concern around resilient EV supply chains and U.S. lithium independence. In 2026 CTR announced plans to go public via a SPAC merger at an implied enterprise valuation of approximately \$4.7B. For the full planned ~500 MW development, the total well inventory could plausibly reach on the order of 50–100+ total wells over time, including replacement and make-up wells.

4. Potential size of global geothermal market by 2035 and 2050

TNI projects global geothermal power capacity will reach 80 GW by 2035 and 220 GW by 2050, driven by Next-Generation Geothermal power technologies that expand the viable resource base well beyond conventional hydrothermal reservoirs. All figures refer exclusively to electricity generation capacity. Delivering this build-out requires cumulative capital investment of approximately \$350B by 2035 and \$1.1T by 2050, implying annual deployment of roughly \$35B per year through 2035, accelerating thereafter. Applying an 80% modelled capacity factor (broadly mid-range of the 70–90% empirical geothermal benchmark) and PPA prices of \$65–85/MWh, this translates to an annual global revenue pool of \$35–45B by 2035 and \$100–130B by 2050, with geothermal’s share of global electricity generation rising from approximately 0.3% today to 1.2% by 2035 and 2.7% by 2050. On an emissions basis, TNI estimates this deployment avoids approximately 300 Mt CO₂ per year by 2035, rising to 700–900 Mt CO₂ per year by 2050 as geothermal displaces the marginal fossil fuel generation mix, equivalent to around 1.5% of current global greenhouse gas emissions measured in CO₂e.

Exhibit 12

Summary of TNI base-case projections (electricity generation only):

Year	Global Geothermal Power Capacity (GW)	Cumulative CAPEX (\$B)	Revenue Potential (\$B p.a.)	Avg. Annual Growth Rate
2035	80	350	35–45	~14–15 % p.a. (2024–35)
2050	220	1,100	100–130	~7–8 % p.a. (2035–50)

Source: TNI analysis

Notes:

- (1) TNI base-case projection. Capacity and growth rates are taken directly from an internal TNI synthesis of IEA and DOE Geothermal Shot reports alongside LCOE modelling. Investment and revenue figures are derived using TNI’s projected Next-Generation Geothermal capital costs (\$5–6 M/MWe) and LCOE trajectories.
- (2) Cumulative Investment Calculation: Assumes addition of ~63 GW new capacity by 2035 (to reach 80 GW from today’s 16.9 GW) and ~203 GW by 2050 (to reach 220 GW) at \$5–6 M/MW.
- (3) Approx. Revenue Potential Calculation: Annual generation is derived by applying a modelled 80% capacity factor to total installed capacity, this generation is then multiplied by an assumed average PPA price of \$65–85/MWh, yielding \$35–45B annually by 2035 and \$100–130B annually by 2050.

While conventional hydrothermal systems define today's market, the next phase of growth is expected to come from a set of technologies that remove the historic constraint of naturally occurring hydrothermal reservoirs. These include Enhanced Geothermal Systems (EGS), Advanced Closed-Loop (ACL), Geopressured Geothermal Systems (GGS) and Super-Hot Rock (SHR). Each seeks to access subsurface heat independent of permeable, water-bearing formations, materially expanding the geographic footprint of viable development. Drawing on drilling, completion and subsurface engineering techniques pioneered in the shale gas industry, Next-Generation Geothermal is envisioned to create an entirely new industry that will dwarf its hydrothermal reservoir-constrained predecessor.

The ultimate geothermal energy market size will be most obviously determined by its competitive economics vs the source of energy it seeks to substitute, which is largely natural gas for both heat and electricity. Accordingly, this paper's primary focus is on the projected leveled cost of energy (LCOE) for each technology being deployed as Next-Generation Geothermal energy. Long-term cost trajectory forecasts are tied mostly to drilling technology learning rates, site selection technology, multi-well platform sizes and the cost of capital. Chapter 7 constitutes our deep dive into the likely range of future costs of geothermal energy, which we would say will be challenging to manage, but given the baseload and low carbon nature of the energy source, we believe NGG will be competitive and our market growth forecasts below reflect that conclusion.

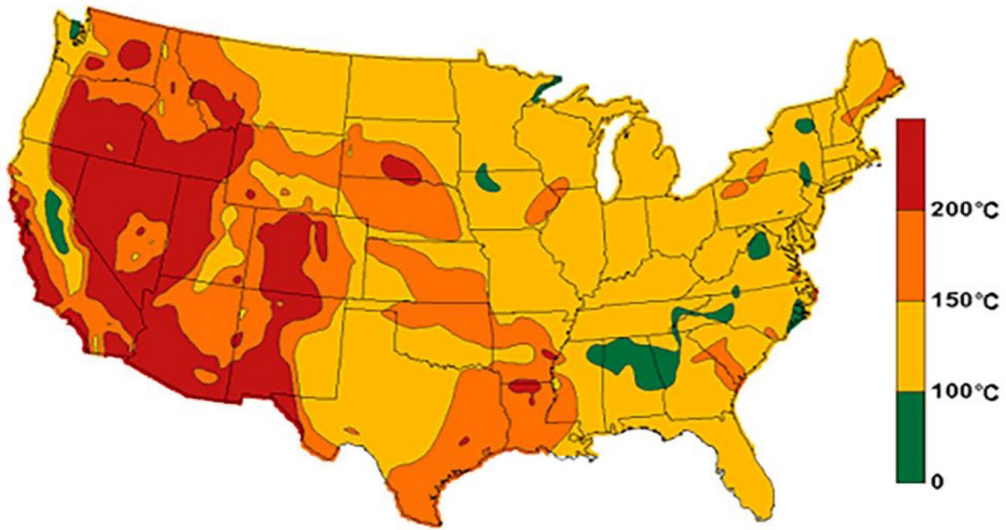
The United States is currently the primary proving ground for Next-Generation Geothermal systems, driven by its concentration of technical innovation, access to drilling expertise due to the pre-existing shale gas industry, supportive federal tax incentives, and deep capital markets capable of financing early commercial deployment. However, cheap natural gas raises the bar for geothermal relative to Europe, so both markets present significant growth opportunities with different economic and competitive dynamics.

In the US, installed geothermal capacity stands at approximately 3.9 GW today, almost entirely conventional hydrothermal. The DOE Geothermal Shot initiative projects scale-up to 40 GW by 2035 and 90 GW by 2050, contingent on sustained reductions in drilling costs, improved well productivity and continued policy support. McKinsey's 2025 analysis estimates a similar 2050 range of 85 to 110 GW, based on bottom-up modelling of resource quality, drilling efficiencies and projected demand growth.

TNI's U.S. point estimate, which reflects our LCOE forecasts, leads us to believe that the DOE Geothermal Shot projections are broadly achievable and are likely to reach 40 GW by 2035 and 90 GW by 2050, representing a growth rate of 24% p.a. from 2025-35 and 6% p.a. from 2035-50. This reflects strong but achievable Enhanced Geothermal Systems deployment under continued technology improvement. Commercial validation in the United States is likely to determine the pace and credibility of subsequent international adoption.

Exhibit 13

The United States hosts high-quality geothermal resources concentrated in the Western region



Source: DOE (2026)

Europe currently hosts approximately 3.5 GW of geothermal power capacity generating around 20 TWh annually, with Türkiye, Italy, and Iceland accounting for nearly all output. Beyond these established markets, development activity is spreading. Several other countries already produce geothermal electricity, including Croatia, France, Germany, Hungary, Austria and Portugal, while new capacity is under development in Belgium, Slovakia and Greece. Across Europe, around 50 geothermal power plants are currently moving through development, from early exploration to grid connection, with Germany leading in active projects.

The resource base is substantially larger than current deployment suggests. Bottom-up analysis by Ember (2026) identifies 43 GW of EGS capacity in EU member states developable at costs below €100/MWh today, consistent with prevailing coal and gas marginal costs in European power markets. Türkiye and Iceland are not EU member states but are included in Ember's analysis. Ember's estimates do not cite a year, but rather how much can be theoretically produced at various cost thresholds. At

geothermal's typical capacity factor, this implies potential generation of approximately 301 TWh per year, equivalent to 42% of all EU coal and gas generation in 2025. According to the Ember report, Hungary accounts for the largest share of prospective growth at approximately 28 GW, followed by Poland, Germany, and France at roughly 4 GW each.

Independent integrated assessment modelling by Dalla Longa and van der Zwaan (2020) more conservatively projects European geothermal electricity generation reaching 100–210 TWh per year by 2050, a 4–7% share of European power generation, with an associated capital investment of \$160–210B per year by 2050. IRENA is directionally consistent, projecting an eight-fold increase in European geothermal capacity by 2050 to 28 GW. Business-as-usual forecasts are far more conservative: the EIA projects EU capacity reaching only 8 GW by 2030 and plateauing thereafter, reflecting a continuation of current policy rather than any NGG power cost reduction scenario.

Europe faces both structural and regulatory

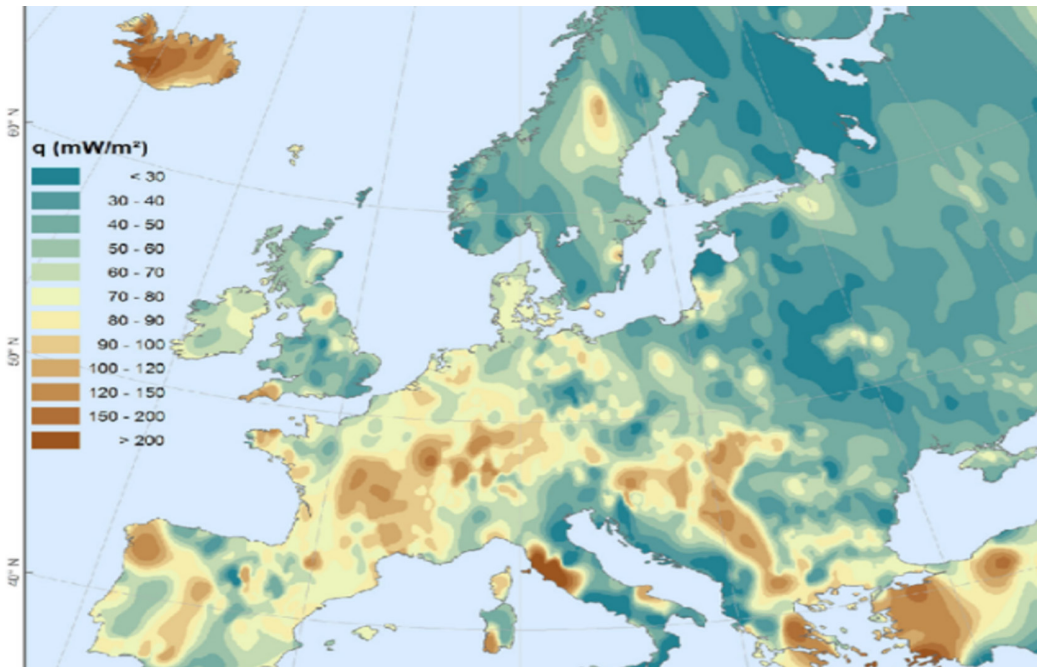
constraints. Outside of Iceland, Türkiye and Italy, European subsurface gradients are typically 20–30°C/km versus 45–60°C/km in the Western US, which materially limits the cost-competitiveness of EGS-for-power across much of the continent and means Europe is most likely to lead in geothermal-for-heat and CHP applications rather than power generation. Regulatorily, permitting timelines are lengthy, national policy frameworks are inconsistent, and shared subsurface data is limited. TNI's view of 8 GW by 2035 and 20 GW by 2050 assumes meaningful cost reductions and a gradual improvement in the policy environment, without assuming a step-change in permitting or coordinated EU-level intervention in the near term. It is the most

exposed line item in our 220 GW global 2050 base case.

Capital markets compound these constraints. Geothermal investment in Europe is dominated by government and corporate sources (~73% of total), with venture capital and private equity contributing only ~21% — versus a 36% / 61% US split (Underground Ventures & alfa8, 2026). A thinner risk-capital base limits how many independent developers can be financed through the demonstration-to-commercial transition, and where the underlying resource economics are already harder, the absence of deep venture funding compounds rather than offsets the structural disadvantage.

Exhibit 14

Europe's geothermal resource base is highly concentrated in Iceland, Türkiye and Italy, with very low gradients in the rest of Europe



Source: Chamorro (2013)

Notes:

"q" is a measure of heat flux density which is how fast heat is moving through a surface. 100mW/m² means 0.1 watts of heat energy passing through each square metre every second.

For **China and Rest of the World (ROW)**

we forecast 110 GW of electricity generation capacity by 2050 — comprising 50 GW from China, 35 GW from South Asia (principally India and Indonesia), and 25 GW from the rest of the world. This target is primarily based on the IEA assertion that China, India, and the United States together possess three-quarters of the global market potential for Next-Generation Geothermal electricity.

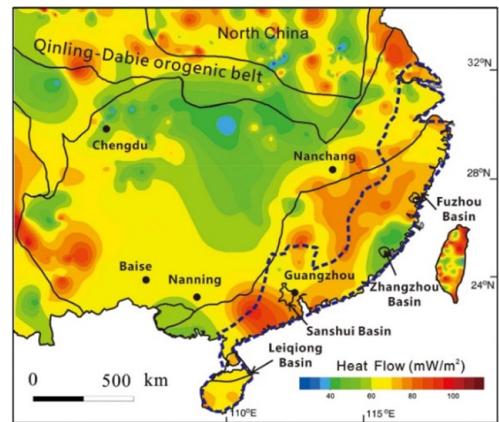
China has the single largest potential geothermal power market globally, expected to account for around 23% of global geothermal capacity by 2050. Today, China is the world leader in geothermal direct-use heating (~168 GWth of thermal capacity, two-thirds of global direct-use capacity) but has almost no geothermal electricity generation — less than 50 MW of installed power capacity, with its only significant power plant (Yangbajing, Tibet, 24 MW) having ceased operations in 2020. The distinction matters: direct-use heating operates at low temperatures (typically 40–90°C) from shallow wells and requires no power conversion equipment, whereas electricity generation requires high-temperature resources (>150°C), deeper drilling, and fundamentally different surface plant infrastructure. China's 168 GWth of heating capacity cannot be converted to electricity — these are different systems serving different purposes. However, China's extensive subsurface data from its heating programmes, combined with deep drilling capabilities developed for oil and gas, provide a foundation for future EGS power development. To maintain energy security while transitioning away from coal-fired power, the country needs to deploy nearly 700 GW of low-emissions dispatchable electricity capacity over the next 25 years. The IEA estimates that a significant share of this could be met by geothermal if EGS costs fall sufficiently — but this is contingent on commercialising EGS technology at scale, which China has not yet done.

The IEA's 2024 assessment estimates China's EGS technical resource base at approximately 50 TW — a measure of total thermal energy

stored in rock at depths up to 8 km, not a capacity forecast. For context, TNI's entire global 2050 projection of 220 GW represents roughly 2% of the ~10,000 GW MIT estimate of commercially accessible NGG resource (and a vanishing fraction of the much larger raw thermal resource). The practical question is not resource availability but engineering cost and capability. China's naturally occurring high-temperature hydrothermal resources suitable for electricity generation are heavily concentrated in southern Tibet, western Sichuan, and western Yunnan (~84% of known high-temperature surface expressions). The EGS thesis is that engineered reservoirs can access elevated heat flow across a much wider area — including the North China, Songliao, and Gonghe basins — provided drilling costs fall enough to make these deeper, moderate-gradient resources economic for power generation. TNI forecasts China reaching 10 GW by 2035 and 50 GW by 2050, reflecting the country's extensive subsurface data from heating programmes and deep drilling capabilities, offset by the fact that it is starting from essentially zero installed electricity capacity.

Exhibit 15

China's subsurface heat resource is geographically widespread, providing a large addressable base for geothermal power



Source: Zheng et al. (2021)

In the ROW, India is positioned as the third-largest global market for Next-Generation Geothermal power capacity by 2050, needing clean firm power to complement its massive solar PV growth. Southeast Asia holds substantial EGS potential, led by traditional geothermal powerhouses Indonesia and the Philippines — the IEA estimates the region’s theoretical EGS thermal resource at approximately 125 TW, or about 20% of the global total. Africa possesses not only the world’s largest untapped conventional hydrothermal potential but also approximately 115 TW (~20%) of global EGS theoretical resource. To illustrate the scale of this physical endowment, the IEA notes that tapping less than 1% of Africa’s EGS resource would generate enough electricity to meet all of the continent’s needs by 2050. As with China, these theoretical resource figures measure thermal energy in rock, not deployable capacity — the commercially viable fraction will depend on the same EGS cost reductions discussed throughout this paper. TNI forecasts South Asia reaching 12 GW by 2035 and 35 GW by 2050, and the rest of the world reaching 10 GW by 2035 and 25 GW by 2050.

A common feature of leading next-generation geothermal developers is the pursuit of multi-country strategies that diversify geological, regulatory and offtake risk across regional power markets. Ignis Energy operates across the Western US and Indonesia, while Baseload Capital has built geothermal IPP exposure across the US, Iceland, Japan and New Zealand. Eavor is developing projects in Germany, Finland and the US, with its first commercial project at Geretsried in Bavaria. However, unlike oil and gas, next-generation geothermal remains fundamentally a regional infrastructure business: electricity cannot economically be shipped far beyond local transmission systems, limiting the diversification benefits of multinational asset ownership itself. The stronger strategic rationale for international expansion may therefore lie in the transferability of technical and development expertise — siting, drilling, stimulation and reservoir engineering— which can be replicated across jurisdictions through repeat-project execution, partnerships or licensing models even if the underlying power markets remain local.

Exhibit 16

TNI Global Geothermal Capacity Forecast Summary drawing on third party expert sources (Electricity Generation Only)

Region	Current Capacity (2024)	2035 TNI Forecast (GW)	2050 TNI Forecast (GW)	Core Rationale & Sources
United States	3.9 GW	40	90	ThinkGeoEnergy (2025); DOE Liftoff Report (2024); McKinsey (2025)
Europe / UK	3.5 GW	8	20	ThinkGeoEnergy (2025); Ember (2026); EGEN (2024); most exposed line item in the 220 GW base case — see structural gradient, permitting and capital-market constraints on pp. 22–23
China	<0.1 GW	10	50	IRENA (2023); IEA (2024)
South Asia (India & Indonesia)	4.6	12	35	ThinkGeoEnergy (2025); IEA (2024)
Rest of World (ROW)	4.9	10	25	ThinkGeoEnergy (2025); IEA (2024)
Global Total	~16.9 GW	80 GW	220 GW	TNI Point Estimate

Notes:

- (1) All figures refer exclusively to electricity-generation capacity (not direct-use heat)
- (2) Regional forecasts sum exactly to the TNI global point estimate
- (3) All TNI point estimates are derived from internal synthesis of IEA, DOE, McKinsey, Ember EGEC and ThinkGeoEnergy sources, consistent with the LCOE trajectory and regional build-up in the text above.

As shown in Exhibit 17, global geothermal market size projections by experts diverge significantly due to varying input assumptions for geology, regulatory regimes, capital markets and public acceptance across markets. The IEA's Future of Geothermal Energy report published in 2025 outlines a medium-cost case reaching 190 GW of next-generation capacity by 2050 (which, combined with 80 GW of conventional capacity, totals 270 GW). In this medium-cost IEA scenario, construction costs are estimated at \$7,000/kW in 2035, declining to approximately \$5,000/kW by 2050, resulting in a levelized cost of energy (LCOE) of \$120/MWh in 2035 and \$70/MWh by 2050.

The IEA's low-cost case projects 120 GW of next-generation capacity by 2035 and over 800 GW by 2050, predicated on rapid construction cost declines driven by innovation and synergies with the oil and gas sector. Under this low-cost case, construction costs fall to roughly \$3,000/kW by 2035 and \$2,000/kW by 2050 — an 80% reduction from today's levels, driving the LCOE down to about \$50/MWh in 2035 and \$30/MWh in 2050. More conservative integrated assessment modelling from van der Zwaan & Dalla Longa (2019) projects deployment of 100–150 GW by 2050.

We arrive at a point estimate for global geothermal capacity of 80 GW by 2035 and 220 GW by 2050. Our estimates are derived from a synthesis of the expert forecasts cited above — IEA, DOE, McKinsey, Ember, and ThinkGeoEnergy — weighted by the depth and specificity of each source's underlying methodology. The 2035 estimate sits between the IEA medium and low-cost cases, reflecting our view that construction costs will decline meaningfully (consistent with the drilling learning rates laid out in Chapter 7) but that the pace of international permitting and supply chain scale-up will

lag the IEA's most optimistic assumptions. Our 2050 estimate of 220 GW is moderately below the IEA's medium-cost case (270 GW) rather than the low-cost upside (850 GW), because we assume: (i) slower permitting reform outside the US, particularly in Europe and emerging markets; (ii) supply chain bottlenecks in specialist drilling rigs and completion equipment persisting into the 2030s; and (iii) grid interconnection and transmission build-out acting as a binding constraint in several key markets. These are not execution risks in the abstract — they are specific input assumptions where our view differs from the IEA's low-cost scenario, which assumes these frictions are resolved by the mid-2030s.

The IEA and BloombergNEF project total global installed power capacity to reach ~20–22 TW by 2035 and ~29–35 TW by 2050. The IEA projects that cumulative global investments in Next-Generation Geothermal electricity capacity will range from \$350B to \$700B by 2035 and will scale to between \$1 trillion and over \$2.1 trillion by 2050, depending on the pace of cost reductions. In the U.S. market alone, the Department of Energy estimates that deploying 90 GW of Next-Generation Geothermal will drive \$225–250B in capital investment. Our 220 GW 2050 forecast implies geothermal's share of global installed electricity capacity rises from roughly 0.2% today to ~0.7% by 2050. However, Geothermal's structural advantage lies in its high-capacity factor of ~70–90%, materially above most other power sources. As a result, its share of electricity generation exceeds its share of installed capacity. Under TNI's forecast, geothermal increases from ~0.3% of today's 31,000 TWh of global electricity generation to ~1.2% of projected 45,000 TWh (IEA & Bloomberg NEF) in 2035 and ~2.7% of projected 57,000 TWh in 2050. We estimate that this growth to 80 GW by 2035 will substitute mostly for gas power

plant builds and avoid 250-350 Mt of carbon emissions in 2035, just ½ of 1% of global emissions. Our 2050 estimate of 220 GW of geothermal power would avoid 700-900 MtCO_{2e} annually, equivalent to about 1.5% of current global emissions.

In Chapter 8, we discuss the many headwinds and challenges that EGS will face, including the technical concerns over water use, heat dissipation and restimulation needs, along with the physical limitations from rig and equipment access, permitting and grid connection. We translate these into our a slower deployment scenario, in which

capital constraints persist and oil & gas major participation is delayed by 5–10 years beyond our central case. We estimate that this scenario would still yield approximately 50 GW by 2035 and 150–180 GW by 2050. This case assumes IRR convergence between geothermal and core upstream O&G takes longer than expected, infrastructure capital remains cautious until later in the technology curve, and Europe lags meaningfully due to subsurface gradient constraints discussed below. Even in this scenario, the market triples from current capacity by 2035, but with revenue pools and exit multiples materially compressed.

Exhibit 17

Experts' vs TNI forecast of global geothermal power capacity: 2035 and 2050

Source	Current capacity (2025)	Future capacity (2035)	Future capacity (2050)	Comments
Global				
IEA Future of Geothermal Energy (2025) Global market potential (Medium cost case)	15 GW	50-60 GW	270 GW	IEA Announced Pledges Scenario modelling market potential contingent on cost reductions, policy and social acceptance, medium-cost assumes slower learning and higher residual drilling costs
IEA Future of Geothermal Energy (2025) Global market potential (Low-cost case)	15 GW	110-120 GW	850 GW	IEA Announced Pledges Scenario modelling market potential contingent on cost reductions, policy and social acceptance, low-cost assumes rapid 80% construction cost declines via innovation and oil-gas synergies
van der Zwaan & Dalla Longa (2019) Global			100-150 GW	Uses TIAM-ECN integrated assessment model to simulate geothermal deployment under climate policy and cost-learning scenarios to 2050
TNI Point Estimate	17 GW	80 GW	220 GW	Anchored to ThinkGeoEnergy (2026) current capacity. The 2035 estimate (80 GW) sits between IEA medium and low-cost cases, assuming meaningful but capped cost declines. The 2050 estimate (220 GW) reflects sustained learning and policy support, but below the low-cost upside case due to deployment and system constraints and close to the integrated assessment of van der Zwaan & Dalla Longa.

Source	Current capacity (2025)	Future capacity (2035)	Future capacity (2050)	Comments
United States				
DOE Geothermal Shot Target (2022) U.S.	4 GW	40 GW	90 GW	Updates GeoVision technology assumptions (drilling costs, well productivity, resource depth) and models U.S. EGS deployment to 2050 using the ReEDS capacity expansion model under deep decarbonisation scenarios
DOE GeoVision Max Potential Scenario (2019) U.S.	3 GW	40 GW	120 GW	Uses ReEDS modelling comparing BAU, Technology Improvement and high gas price scenarios, incorporating simultaneous cost reductions, technology improvements and favourable market conditions.
McKinsey (2025)		40 GW	85-110 GW	Combines bottom-up LCOE modelling (resource quality, drilling, flow rates, financing sensitivities) with U.S. demand growth assumptions and competitive market analysis to estimate deployment by 2050.
TNI Point Estimate	4 GW	40 GW	90 GW	Anchored to DOE reported capacity. The 2050 estimate (90 GW) is aligned to DOE's central ambition, assuming strong but achievable long-term EGS deployment and is in-line with McKinsey's forecast.

Proof of growth momentum is provided by Exhibit 18 below. The geothermal power sector is at an early but identifiable commercialisation inflection point. Drilling and reservoir engineering improvements are converting from laboratory and pilot-scale progress into contracted commercial scale projects: as Exhibit 18 shows, long-term PPAs between NGG power developers and creditworthy counterparties, including utilities and hyperscalers, have accelerated materially since 2023, supported by federal tax incentives and corporate clean power procurement mandates. On the demand side, AI-driven data centre load growth

and broader electrification are intensifying the premium placed on firm, dispatchable, carbon-free generation, a profile that intermittent renewables cannot replicate without storage. The convergence of falling supply-side costs and structurally rising demand for reliability creates the conditions for sustained capacity growth. At a capacity factor of 80% and PPA prices of \$65–85/MWh, TNI's forecast of 80 GW by 2035 and 220 GW by 2050 implies an annual global revenue pool growing from approximately \$35–45B in 2035 to \$100–130B by 2050, a market of comparable scale to today's entire global offshore wind sector.

Exhibit 18

Long-term PPAs signal Next-Generation Geothermal is reaching an inflection point

Company	Partner	Partnership phase	Power delivery (MW)	Press date	Partnership details
Fervo Energy	Google	Geothermal Framework Agreement (non-binding)	3,000	March 2026	The largest single buyer commitment in the geothermal sector to date. Structured as a multi-gigawatt roadmap for hyperscale clean firm power buildout, building on Google's earlier 115 MW CTT deal. While non-binding, it sets a template for how hyperscalers can underwrite multi-GW geothermal commitments.
XGS Energy	Meta	LOI	150	June 2025	Meta will support XGS's development of 150 MW Next-Generation Geothermal production in New Mexico
Fervo Energy	Shell Energy	PPA	31	April 2025	15-year PPA, with Shell as the first named offtaker for Cape Station Phase I — deliveries beginning 2026. Followed Shell's exit from Dutch geothermal heat development (February 2025), repositioning Shell from direct developer to long-term offtaker. The contracted volume sits within the broader Cape Phase I expansion from 400 MW to 500 MW.
Sage Geosystems	Meta Platforms, Inc.	LOI	150	August 2024	Sage's proprietary Geopressured Geothermal System will be used to power data centres
Fervo Energy	Southern California Edison	PPA	320	June 2024	15-year PPA — the world's largest geothermal PPA at signing. Fervo's Cape Station project is forecasted to meet the energy demand of approximately 350,000 homes in Southern California. SCE's 320 MW concentration represents roughly half of Fervo's 658 MW total contracted backlog, creating customer-concentration risk that Fervo discloses in its S-1.
Fervo Energy	NV Energy, Google	CTT approved	115	June 2024, May 2025	Google established a clean transition tariff (CTT) deal with a Nevada utility company, which worked with Fervo to activate EGS capacities
Fervo Energy	Clean Power Alliance	PPA	48	2024	15-year PPA, structured as an initial 30 MW base contract with an 18 MW expansion. Adds Clean Power Alliance — a Southern California community choice aggregator — to Fervo's California offtake stack alongside SCE.
Eavor	Sonoma Clean Power	LOI	200	March 2023	Through the GeoZone partnership, Sonoma Clean Power privately contracted energy from Eavor

Source: McKinsey; Company Press Releases

5. Which Next-Generation Geothermal technologies will drive market growth?

Next-Generation Geothermal encompasses four primary technologies: Enhanced Geothermal Systems (EGS), Geopressured Geothermal Systems (GGS), Advanced Closed-Loop (ACL), and Super-Hot Rock (SHR). Each is designed to overcome the geological constraints that have historically limited geothermal to a small fraction of global energy supply. EGS creates artificial reservoirs by hydraulically stimulating hot, impermeable rock, enabling scalable geothermal development wherever sufficient heat exists. GGS leverages naturally high-pressure, fluid-filled sedimentary formations, offering both power generation and long-duration energy storage but requiring a rare combination of pressure, temperature, and permeability. ACL systems circulate fluid through sealed underground loops, eliminating water loss and seismicity risks but delivering lower power density due to reliance on conductive heat transfer. SHR targets supercritical resources (>374°C) with the potential for dramatically higher output per well. Whether breakthrough drilling is required depends largely on depth: high-gradient volcanic sites — The Geysers, Larderello, Iceland, Imperial Valley, and Newberry Volcano (where Mazama Energy recorded 331°C with conventional drilling in 2025) — can reach near-supercritical temperatures within ~5 km using existing equipment. The harder constraint is the Brittle-Ductile Transition zone: below it, hydraulic fracturing becomes ineffective, and developers will likely need advanced closed-loop architectures rather than EGS-style stimulation.

EGS is emerging as the most credible pathway to scale. It combines access to higher-temperature resources with engineering repeatability, drawing directly on proven oil and gas techniques such as horizontal drilling and hydraulic stimulation. This enables learning-curve cost reductions and increasing output per well, positioning EGS as the most likely route to utility-scale, firm, low-carbon power in the near to medium term. While developers will ultimately select technologies based on site-specific geology, EGS uniquely expands the addressable resource base and provides a practical bridge from today's conventional geothermal systems to a more scalable future. Other approaches will play important but more targeted roles—GGS in specific sedimentary basins or storage applications, ACL in jurisdictions sensitive to seismicity or water use, and SHR as a longer-term, high-upside frontier—but EGS sets the benchmark for whether Next-Generation Geothermal

can become a material contributor to global energy systems.

Over the long term, Next-Generation Geothermal developers will most likely adopt an “all technologies” portfolio-based, horses-for-courses approach — building capabilities across multiple NGG technologies and deploying the most suitable solution for each specific geological setting — though in the near and medium term most developers will remain specialised in a single core technology.

Investors should not view Super-Hot Rock (SHR) as competing for the same capital pool as other Next-Generation Geothermal technologies, as it sits at a fundamentally earlier stage of development with a distinctly different risk–return profile. While EGS, GGS and ACL are progressing through demonstration toward commercial deployment, SHR

remains at a prototype stage (TRL ~4–5) and depends on the successful maturation of entirely new ultra-high-temperature drilling systems and materials. At the same time, SHR offers the highest theoretical upside in the sector: by accessing supercritical resources at depths typically >5 km and temperatures above 374°C, SHR could deliver 5–10× more energy per well than EGS, materially increasing power density and long-term economics. As such, SHR should be understood less as a near-term competitor to EGS and more as a longer-dated, high-risk, high-reward frontier technology—one that sits on a different part of the development curve and is appropriately funded by investors seeking asymmetric returns rather than near-term, scalable deployment. That

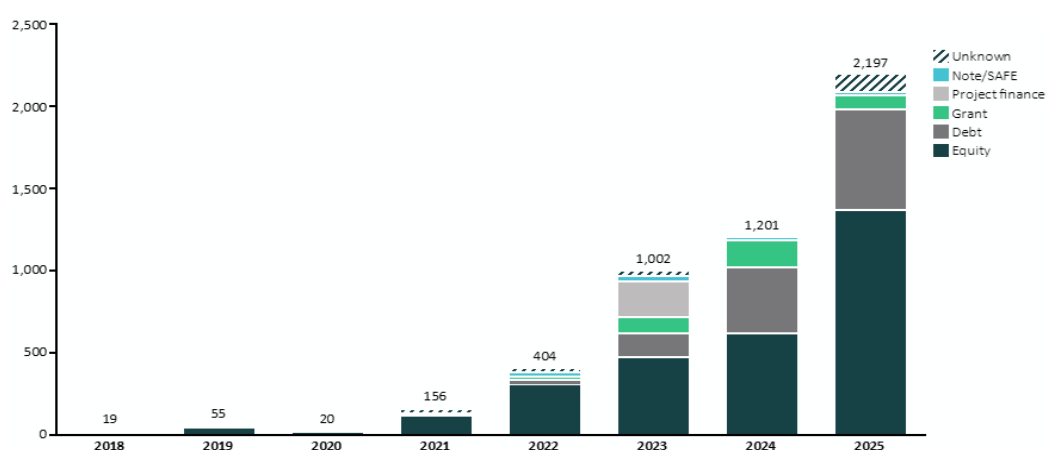
said, the boundary between EGS and SHR is narrowing faster than TRL classifications suggest: Fervo has reached 290°C in commercial wells (April 2026 S-1) and Mazama 331°C in its EGS pilot at Newberry Volcano, both within ~40–80°C of the supercritical threshold of 374°C (see Exhibit 27a in Section 5).

Between 2019 and 2025, approximately \$4.9B of cumulative venture capital and private equity funding flowed into geothermal startups, supporting the commercialisation of next-generation technologies beyond conventional hydrothermal systems. This capital has concentrated around four principal geothermal drilling technologies listed above.

Exhibit 19

Next-Generation Geothermal financing grew rapidly at 97% p.a. from 2018–2025

Next-generation geothermal financing
Millions of USD



Source: IEA analysis based on Cleantech Group (2026), Crunchbase (2026), Underground Ventures (2025).

In this chapter we provide a comparison and assessment of the four most promising Next-Generation Geothermal drilling technologies. As a baseline for comparison, we start with a description of how traditional hydrothermal drilling has been executed over the many past decades.

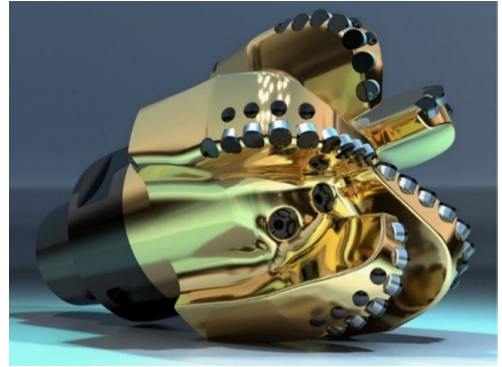
Traditional Hydrothermal Drilling

Traditional geothermal drilling works by drilling deep wells—often 1–3 miles into the earth—into naturally occurring reservoirs of hot water or steam trapped in porous rock. Exploration begins with geological and seismic surveys to identify promising heat sources, after which drilling rigs similar to those used in oil and gas are used to bore production wells.

Traditional geothermal drilling uses rotary drilling technology, essentially the same core method developed in the oil and gas industry, where a drill bit rotates at the end of a drill string to penetrate rock while drilling fluid (mud) circulates to cool the bit and bring cuttings to the surface. Depending on the geology, operators use roller-cone bits (for softer formations) or polycrystalline diamond compact (PDC) bits (for harder rock), along with steel casing and cementing to stabilise the well. However, geothermal wells are typically drilled in much harder, hotter, and more fractured rock than oil and gas, which places extreme stress on equipment and limits the effectiveness of standard oilfield tools.

Exhibit 20

A standard PDC bit used for O&G and geothermal well drilling



Source: Baker Hughes Talon™ Strike 2 PDC drill bit

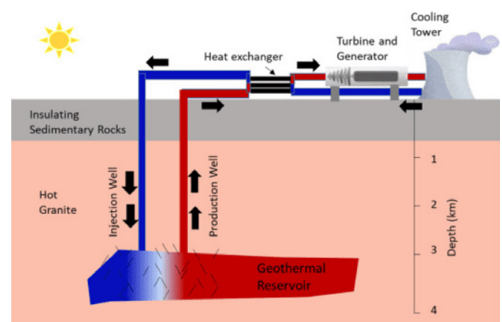
Once a reservoir is reached, high-pressure steam or hot water flows to the surface through the production well and is used to spin turbines that generate electricity. The cooled water is then typically reinjected back underground through separate injection wells to sustain reservoir pressure and create a closed-loop system. This approach relies heavily on finding naturally permeable, water-filled hot rock formations, which is why geothermal development has historically been limited to geologically favourable regions like volcanic or tectonically active areas. Naturally existing permeable hydrothermal reservoirs are confined to <3% of the Earth's surface.

In contrast to oil and gas drilling, geothermal wells have much higher temperatures (often >200–300°C), which can degrade electronics, drilling fluids, and downhole tools designed for cooler oilfield environments. Instead of targeting hydrocarbons in porous sedimentary basins, geothermal drilling often involves crystalline (igneous) basement rock with lower natural permeability, requiring techniques to manage lost circulation (where fluids escape into fractures).

Geothermal wells also tend to be larger in diameter and more vertically oriented, as they are designed to move large volumes of water or steam rather than extract fluids under pressure. Overall, while the surface equipment and basic drilling approach are similar, geothermal drilling is generally more technically challenging, slower, and more expensive per well due to the hotter and harder subsurface environment.

Exhibit 21

All types of geothermal wells have subsurface well infrastructure and above surface power plant infrastructure to convert the heat to electricity



Source: Bukhary (2024)

Next-Generation Geothermal

technology is defined by whatever is not traditional geothermal processes of using rotary drilling vertically to tap into an existing natural reservoir where permeability and fluid pathways already exist. There is no need to create permeability or actively manage the reservoir beyond reinjection—the subsurface system is doing the work. **Next generation technologies introduce active reservoir engineering and more complex well architectures** including often deeper wells with directional or horizontal drilling while engineering stimulation (e.g., hydraulic fracturing or shearing) to create a fracture network that enables fluid circulation—effectively manufacturing permeability. Next-Generation Geothermal tech (e.g., ACL) can architect closed-loop systems instead of relying on fluid interaction with rock. The system uses sealed wellbores (often U-shaped or multilateral) where a working fluid circulates entirely within pipes, extracting heat conductively. This involves more complex well geometries, advanced materials and thermal design, which avoid permeability and fluid-loss issues altogether.

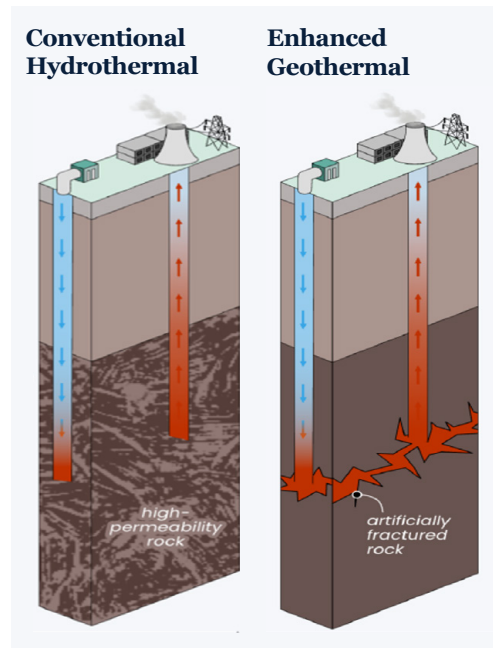
Enhanced Geothermal Systems (EGS)

EGS create permeability in hot, dry rock where none naturally exists. Developers drill wells 2–7 km into formations at temperatures of 150–300°C and use hydraulic stimulation, adapted from the shale industry, to generate connected fracture networks at depth. An injection well and a production well are drilled and linked through these engineered fractures, allowing water to circulate through the hot formation in a closed loop.

Water is injected into hot, low-permeability rock through the injection well, where fractures are engineered to create a subsurface heat exchange reservoir. The water circulates through these fractures, absorbs heat, and is recovered through the production well. At the surface, the thermal energy is used—often via a binary cycle system—to generate electricity by driving a turbine. The cooled water is then reinjected, creating a continuous closed-loop system.

Exhibit 22

Conventional hydrothermal exploits permeable sedimentary rock that acts as an underground reservoir which transfers hot liquid from injection well to production well. EGS works in deeper, hotter and harder igneous rock that has to be fractured to create pathways for hot water to travel from injection well to production well



Source: Bukhary (2024)

How is hydraulic fracturing in shale gas production different from fracturing for geothermal energy? The objectives are different, but the technology is very similar. Hydraulic fracturing in EGS is designed to create a circulating heat exchanger, whereas in shale gas it is designed to release and produce hydrocarbons. But the core equipment is largely the same. The main difference is in how the equipment is deployed. EGS does not require fundamentally new fracking hardware—it largely repurposes oil & gas technology. Both shale fracking and EGS use conventional oilfield hydraulic fracturing equipment including high-pressure pumps (frac spreads), fluid blending units, perforation tools, surface piping and wellhead pressure

control. Shale gas fracking uses large volumes of sand and chemical additives to hold fractures open (proppant). EGS uses no proppant as it creates a permanent flow. EGS operates in hotter and harder rock environments putting more stress on those same tools. In EGS, the emphasis in guiding drilling direction is on geometric placement and reservoir connectivity, rather than long horizontal reach, which is the goal of shale fracking.

EGS is emerging as the most credible Next-Generation Geothermal pathway because it combines engineering repeatability with access to higher-temperature resources and a visible cost-reduction trajectory. The technology relies on standardised drilling and stimulation processes, enabling learning-curve effects similar to shale. By targeting high-grade heat at moderate depths, EGS improves conversion efficiency and increases output per well. As drilling speeds improve and reservoir designs are optimised, well costs are expected to decline, supporting a pathway toward utility-scale clean, firm power.

The most advanced commercial developer of enhanced geothermal systems (EGS) is Fervo Energy. Founded in 2017 and headquartered in Houston, Texas, Fervo has applied horizontal drilling, hydraulic fracturing, and multi-well pad techniques from oil and gas to achieve significantly higher flow rates and better reservoir performance than prior EGS projects. Fervo's commercial pilot, Project Red in Humboldt County, Nevada, has been delivering 3.5 MW of geothermal power to the grid via NV Energy since November 2023, making it the first commercial-scale EGS plant in operation anywhere in the world.

Fervo Energy has now also drilled 28 horizontal wells at Cape Station, Utah, with a 29% 'learning rate', two-thirds cost deflation vs Project Red and flowback of 100 kg/s, suggesting 10–12 MW per well. Fervo also accessed 290°C temperatures from a 3,400 m deep well at Project Blanford in Utah. These locations have 3-4x higher-than-average geothermal gradients. An examination of Fervo's patent filings reveals a strong focus on using fibre-optics and big data to ensure uniform completions.

In December 2025, Fervo closed a \$462M Series E round, bringing total funding to about \$1.5B before its May 2026 IPO added \$1.9B in new capital. It is now advancing its flagship Cape Station project in Utah, where Phase I (100 MW) is on track to deliver first power to the grid in late 2026 and reach ~100 MW of operating capacity by early 2027, with Phase II (a further 400 MW) targeted for 2028 and permits in place to scale to 2 GW.

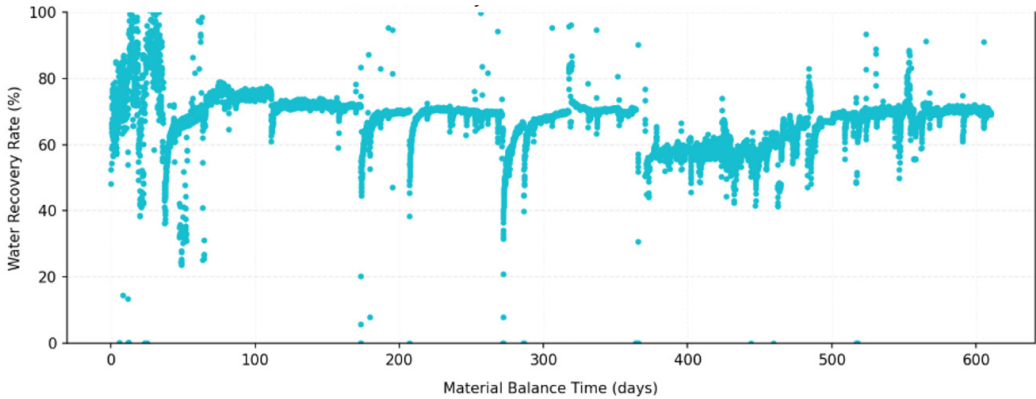
The success of Fervo is far from certain. As evaluated in the cost chapter below, we do see a credible path from current LCOEs of \$90/MWh and higher, to something close to \$55/MWh by 2035. However, the three major risks and costs of water loss, heat dissipation and well restimulation remain uncertain.

What has been the experience of Fervo with water loss? As water circulates through the fracture network, not all of it returns to the production well immediately. A portion migrates into surrounding fractures and pore space, where it is temporarily stored within the reservoir. Early production data, after over 600 days of operation, from Fervo's Project Red shows recapture rates of approximately 70% under steady-state conditions — consistent with expectations for a doublet system geometry.

Exhibit 22a

Fervo's Project Red shows water recapture rates of approximately 70%

Water Recovery Rate vs Material Balance Time



According to an April 2026 Fervo published report on its operational data: “This is more accurately understood as reservoir pressurization and saturation rather than permanent water loss. Fluid that does not immediately return remains within the same hydrogeologic formation, supporting pressure maintenance and long-term productivity. As circulation continues and the reservoir becomes more pressurized, recapture rates are expected to improve. The recapture rate also improves substantially as well designs evolve. Modern EGS configurations — featuring optimized well spacing, multi-well patterns, and improved fracture connectivity — reduce the distance fluid must travel to return to the production well, directly improving recapture efficiency. These designs are expected to achieve recapture rates exceeding 99%, resulting in negligible cost and operational impact over the long term.”

Most geothermal experts do not think water loss is a fatal flaw for EGS, but many do consider it one of the core technical and economic risks that determines whether a project succeeds commercially. Water loss is manageable at good sites with good engineering — but bad fracture behaviour can absolutely kill an EGS project. Clearly, water loss is a risk that remains to be fully understood or contained for EGS.

How will heat dissipation affect the success of any given EGS well? A May 2026 reservoir model published by Thunder Said Energy (TSE) makes clear that most experts’ EGS LCOE estimates assume a well design that can deliver its rated output sustainably across a 30-year asset life. TSE’s modelling shows that an EGS doublet only achieves “truly sustainable” output when laterals are long (~10 km) and the injector-producer spacing is wide enough to sweep large reservoir areas. TSE uses 15 km spacing and a 150 km² swept area in its illustrative case. At that geometry, a well doublet drilled at \$400/ft clears ~\$70/MWh (7c/kWh) at a 10% IRR; at \$200/ft it clears ~\$50/MWh (5c/kWh).

By contrast, TSE estimates that Fervo’s current Cape Station wells run at 1.5 km laterals and ~100 to 150 metre injector-producer spacing, which implies the swept reservoir area is roughly 80% below the sustainable level and that ~80% of today’s per-well heat output is thermal drawdown rather than sustained upward flow. The reservoir will recharge — TSE’s model shows the near-wellbore rock recovering to ~290°C within 1,000 hours of shut-in — but only on a timescale that may not align with continuous baseload operation.

TSE's illustrative geometry implies a doublet drilling cost of ~\$18M at \$400/ft, roughly double Fervo's current Cape Station doublet cost of ~\$9.6M (two wells at ~\$4.8M each). At today's drilling rates this architecture clears ~\$70/MWh at a 10% IRR. Reaching our \$55/MWh 2035 point estimate requires the same drilling-cost halving (toward ~\$200/ft), broadly in line with the productivity gains we expect to see at the well level.

How often will EGS wells need to be re-drilled, re-stimulated or supplemented with make-up wells?

Fervo's two-year operating record at Project Red is an important proof point, but it does not yet answer the key long-term question for investors underwriting 20–25 year project finance. Unlike conventional hydrothermal systems, EGS relies on engineered fracture networks whose long-run degradation profile has not yet been demonstrated empirically over decades of operation. Thermal drawdown, short-circuiting of flow paths, and mechanical well degradation are all understood risks, but their combined impact over 15–20 years remains uncertain.

The critical economic implication is that EGS projects should likely assume periodic make-up drilling and possible re-stimulation as part of the normal cost structure rather than treating wells as one-time capex. Fervo's reduction in drilling costs materially improves this equation: if replacement or supplementary wells can be drilled cheaply, the long-term LCOE impact may be manageable. However, no one yet knows with confidence how frequently such re-drilling will be required or what the ultimate lifecycle economics of large-scale EGS systems will look like.

The success, or failure, of Fervo will in many ways dictate the investment momentum of the global next generation geothermal industry. While Fervo is the most advanced, it is not alone in pursuing EGS — though the broader ecosystem remains thinly capitalised relative to the scale of the opportunity. The sector needs roughly \$35B per year of NGG capex to hit our 2035 build-out projection, but only ~\$5B has gone in over the last five years from new entrants. Exhibit 23 profiles the major companies currently active in the space.

Exhibit 23

EGS ecosystem — developers, oil and gas entrants, and oilfield services providers (2026 Q1)

Pure-Play EGS / Next-Generation Developers

Company	HQ	EGS Activity	Funding / Scale
Fervo Energy	Houston, TX	The most advanced EGS developer globally. Uses horizontal drilling and hydraulic stimulation adapted from shale to create engineered reservoirs. Cape Station Phase I (100 MW, commercial ops targeted late 2026) and Phase II (400 MW, 2028), with permits to expand to 2 GW. As of December 2025, the asset base comprised 3 MW operating (Project Red), 500 MW under construction (Cape), 550 MW Ready to Build, 2.6 GW in Advanced Development and over 38 GW in Early Development across 10 GeoClusters in ~595,900 acres of geothermal leases — acquired at an average of ~\$4/acre, against recent BLM auction prices of \$344–\$410/acre. Total binding offtake of 658 MW representing ~\$7.2B of contracted revenue, anchored by Southern California Edison's 320 MW PPA (June 2024, the world's largest geothermal PPA) and a 3 GW non-binding Geothermal Framework Agreement with Google signed 19 March 2026. ~\$1.5B total raised across Series C–E plus \$421M Cape Station Phase I project finance (March 2026).	\$1.9B raised in May 2026 IPO, with a valuation of \$7.6B. \$1.5B was raised prior to IPO including a Series E \$462M (Dec 2025, led by B Capital).
Google purchasing 115 MW.	110–120 GW	850 GW	IEA Announced Pledges Scenario modelling market potential contingent on cost reductions, policy and social acceptance, low-cost assumes rapid 80% construction cost declines via innovation and oil-gas synergies
Ignis Energy	Houston, TX	"Fit-for-resource" developer using machine learning for site selection across conventional, EGS, and ACL depending on reservoir characteristics. Not EGS-only but includes EGS in its toolkit. Backed by Nabors Industries (drilling contractor).	~\$13.6M Series A (final close June 2025). Led by alfa8, with Nabors Industries commitment.
AlterG	Salt Lake City, UT	Self-described "fast follower" to Fervo. Building a platform combining O&G majors, traditional geothermal developers, and EGS as core technology. Pursuing hyperscaler PPA.	Raising ~\$140M Series A (status unconfirmed as of Q1 2026).

Oil & Gas Majors and Incumbent Geothermal Operators

Company	HQ	EGS Activity	Funding / Scale
Chevron	San Ramon, CA	Direct EGS development via GeoZone pilot near The Geysers, Sonoma County (DOE-selected). Targeting 20 MW demonstration before scaling to 200 MW. 5–8 year development timeline. Also invested in Foro Energy (laser drilling).	Part of broader energy transition capex.
Calpine (now Constellation Energy)	Houston, TX	Largest US geothermal operator (The Geysers, ~725 MW across 13 plants). Operates DOE-funded EGS demonstration well in northwest Geysers (with LBNL). Acquired by Constellation Energy in Jan 2026.	\$16.4B acquisition by Constellation Energy (announced Jan 2025).
Ormat Technologies	Reno, NV	Largest listed pure-play geothermal company globally (~1.2 GW operated). Partnered with SLB (Oct 2025) to co-develop and commercialise EGS, including pilot at existing Ormat facility. Positioned to integrate EGS into existing conventional portfolio.	NYSE-listed. SLB partnership for EGS co-development.

Source: Company filings, DOE, PitchBook, press releases.

Notes:

SLB (via Ormat partnership), Baker Hughes (ORC power plant supplier to Fervo Cape Station Phase II), and Halliburton (downhole tools and cement systems deployed at Fervo Cape Station) are all positioning for geothermal but are covered in detail in Section 12 rather than duplicated here. This section focuses on start-up EGS developers and O&G companies with EGS developments.

Today, EGS costs remain above ~\$90/MWh, but our modelling indicates a pathway toward ~\$55/MWh by 2035 as scale, drilling performance and cost of capital improve. It is the most technically mature next-generation approach, has demonstrated commercial-scale wells, secured long-term PPAs and accessed project finance. Crucially, EGS represents the “base case” for scalable geothermal expansion: it builds directly on conventional drilling, stimulation and oil & gas engineering practices. If EGS cannot close the gap toward ~\$60/MWh and compete with conventional geothermal and other firm clean resources, it is unlikely that more technically complex or less mature approaches, such as ACL or SHR, will achieve cost competitiveness in the same timeframe. For this reason, EGS provides the most realistic benchmark for evaluating whether Next-Generation Geothermal can become a material contributor to future

power markets.

Geopressed Geothermal Systems (GGS)

GGS target deep sedimentary formations that contain both elevated temperatures and naturally high formation pressures. These systems typically operate at depths of 3–6 km and temperatures of approximately 100–250°C. The defining characteristic of GGS is the use of inherent geopressure to assist fluid circulation. This natural pressure can reduce the need for surface pumping, lowering parasitic load and simplifying operations.

Subsurface pressure is primarily the result of a combination of depth, fluid conditions, and how easily fluids can move through the rock. Pressure increases with depth due to the weight of overlying rock and fluids. In a well-connected, permeable system, this

produces normal (hydrostatic) pressure, where fluids can move and equilibrate freely. However, high-pressure zones develop when fluids become trapped and cannot escape—typically due to low-permeability barriers (e.g., shales, seals), rapid sediment burial, or processes like hydrocarbon generation or thermal expansion of fluids. In these cases, pressure builds because fluids are effectively “squeezed” without a pathway to dissipate.

At 3k m depth, hydrostatic pressure (pressure 3km below the ocean’s surface) is ~300 bar (~0.1 bar/m gradient). A geopressed system that would be successful for GGS requires pressure of over 500 bar (or 0.17 bar/m), or 1.5 to 2.5x higher than hydrostatic pressure.

GGS are not easy to find in an economic sense—not because overpressure itself is rare, but because the full combination of required conditions is uncommon. Over-pressured formations exist in many sedimentary basins worldwide, but for a viable GGS you need three things simultaneously: (1) high pressure, (2) sufficiently high temperature,

and (3) high permeability with large, connected fluid volumes to deliver strong flow rates. In practice, many basins have one or two of these, but far fewer have all three at scale, which is why GGS has seen limited commercial deployment despite decades of study. Operators may stimulate the formation to enhance permeability, but the system design relies primarily on leveraging existing pressure rather than creating entirely artificial reservoirs.

These systems are typically found in deep, rapidly buried sedimentary basins, where thick layers of sand and shale trap fluids and prevent pressure from dissipating. Classic examples include the U.S. Gulf Coast basin (Texas and Louisiana), which has been the main focus of historical GGS projects, as well as parts of the North Sea, South China Sea, and other large deltaic basins worldwide. The key geological setting is one where porous sand layers (reservoirs) are sealed by low-permeability shales, creating trapped, high-pressure fluids that are also heated by depth.

Exhibit 24

Sage Geosystems’ geopressed geothermal system (GGS) demonstrates scalable baseload power and energy storage capability



Source: Sage Geosystems Press Release

A distinguishing feature of GGS is its flexibility in configuration. The system can operate either as a continuous baseload generator or as long-duration energy storage. However, current commercial development is primarily focused on the energy storage application, where GGS functions as a subsurface long-duration energy storage (LDES) system. In this configuration, excess electricity, often from solar generation, is used to inject fluid into the formation and store energy as pressurised water within expanded fractures. When electricity is required, the pressurised fluid is released to drive a turbine and generate power. Storage durations can range from several hours to multiple days, positioning GGS as a potential alternative to pumped hydro or large-scale battery systems for long-duration applications. When paired with solar generation, the system can provide dispatchable power and enable 24/7 clean electricity supply. An important distinction is that the geographic applicability differs between GGS's two modes: the energy storage application has broader site flexibility because it depends more on pressure containment than on high reservoir temperatures, whereas the power generation application still requires the full triple coincidence of pressure, temperature, and permeability, a meaningfully narrower set of sites.

Sage Geosystems has demonstrated this concept through a single-well “huff-and-puff” configuration. In this approach, fluid is injected under pressure to expand fractures and store energy within the formation. The pressurised hot fluid is later released through the same well to drive a turbine and generate electricity. While the underlying geothermal

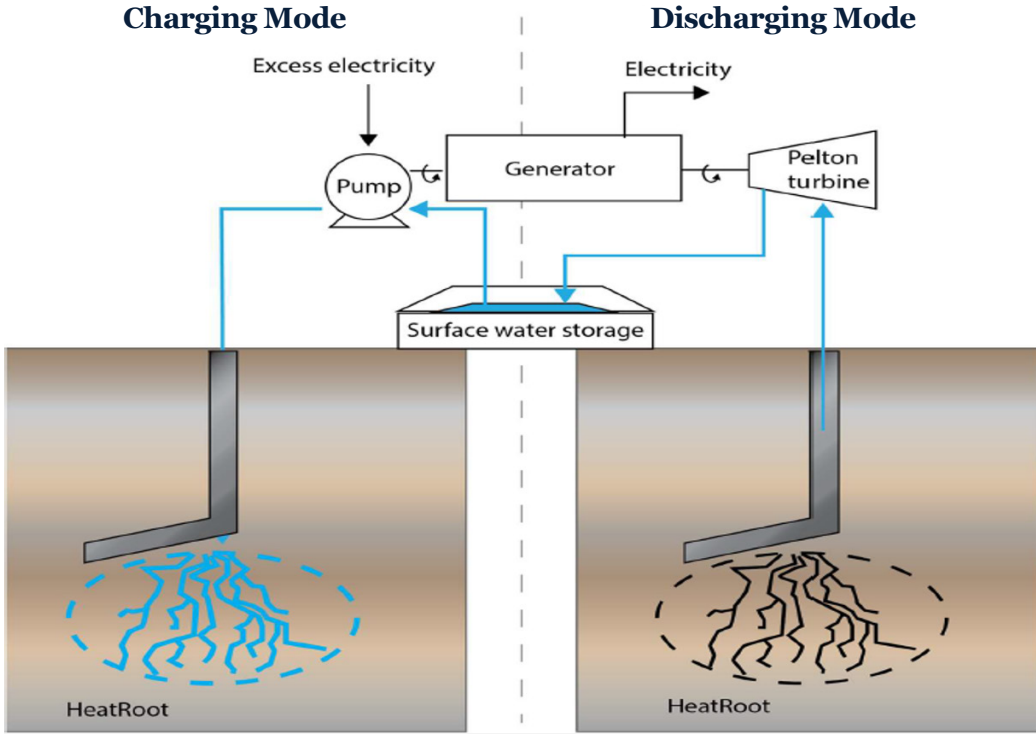
resource contributes heat to the system, the primary value proposition today is grid-scale energy storage that can firm intermittent renewable generation, particularly solar.

Sage Geosystems, founded in 2020 and headquartered in Houston, Texas, is currently the leading commercial developer of geopressured geothermal systems, which the company refers to as Pressure Geothermal. Sage commissioned a 3 MW facility in Christine, Texas in 2025. The project demonstrated hybrid power generation and long-duration energy storage capability, delivering dispatchable power to the ERCOT grid for 4–6 hours. In January 2026, Sage closed an oversubscribed \$97M Series B funding round co-led by Ormat Technologies and Carbon Direct Capital. The capital will fund deployment of Sage's first commercial Pressure Geothermal power generation facility at an existing Ormat plant in the western United States, targeting commissioning in late 2026 to early 2027.

As shown in Exhibit 25, the Sage huff-and-puff system operates with two independent single-well systems, which are each connected to their own stimulated fracture zone. The left well operates in charge mode. Fluid is injected at high pressure to expand fractures and store energy in the form of reservoir pressure and heat. The well on the right operates in discharge mode. Pressurised hot fluid flows back to surface and goes through a high-pressure heat exchanger (HPHX) that drives a turbine to generate electricity. The cycles are staggered so one well charges while the other discharges, enabling more continuous power output than a standalone single “huff-and-puff” well.

Exhibit 25

Geopressedured Geothermal Systems – Sage’s “Huff and Puff” Pair HeatRoot GGS



Source: Sage Geosystems

Sage management aim to be competitive with EGS LCOE estimates today ranging from \$75 to \$115/MWh. Sage’s system for GGS offers the following economic benefits:

- **Lower Pumping Costs:** Unlike standard EGS that requires high-volume, high-pressure pumping for circulation, Sage’s gravity-assisted fracturing uses heavier fluids and Earth’s natural lithostatic pressure to do the “work” of fracturing. Furthermore, by maintaining high pressure throughout the entire system (the “hourglass” effect), Sage greatly reduces the pumping energy required for reinjection. The 70–75% round-trip efficiency reported for the SMECI facility, if independently verified, would place Sage’s storage system at the upper end of mechanical storage technologies and comparable to lithium-ion batteries, a strong result, though no independent

third-party validation of this figure has been published to date.

- **Minimal Water Loss:** While traditional EGS often faces “moderate” water dependence due to adsorption into fractured rock or uncontrolled migration, Sage targets “tight” geologies with very low permeability. This confines fluids to the induced network, with water losses estimated to remain under 2%.
- **Drilling Efficiency:** Drilling and completions have historically accounted for 30–57% of total geothermal costs. Sage’s ability to fracture downward from the well bottomhole allows it to reach higher temperatures without the cost of drilling to those full depths. Sage claims this downward propagation can extend up to 2 km below the wellbore using its HeatRoot gravity-assisted fracturing

technique with high-density fluids (barite, hematite). However, independent sources have confirmed fracture extensions of only “several hundred feet” below the wellbore to date. The 2 km figure appears to represent a theoretical maximum rather than a demonstrated result and should be treated accordingly.

- **Shared Infrastructure:** In the next phase of development, Sage plans to retrofit underutilised Ormat facilities. This allows Sage to utilise existing above-surface power plant equipment (Organic Rankine Cycle plants), established processes, and personnel. Sage claims 80% shared technology between its power generation and energy storage systems, and a drill-and-complete time of approximately one month per well, with a 12-month cycle from capital raise to project completion.
- **LDES and Realized Revenue.** Sage’s pressurised approach provides strong operational flexibility, allowing it to transition from baseload power to dispatchable energy, sold at higher prices.

These economic benefits may go a long way toward matching EGS economics. Sage’s long-term target LCOE is \$0.065/kWh (\$65/MWh) for power generation and \$2.25M/MW capex for energy storage. If achieved, this would be competitive with onshore wind and below nuclear (\$0.11/kWh) and offshore wind (\$0.13/kWh), according to NREL ATB 2024 estimates cited in Sage’s materials. The pathway from a 3 MW demonstration to the scale implied by these unit economics remains unproven.

However, due to the rarity of economically viable sites, delivering pressure, heat and the right permeability, GGS should be viewed primarily as a niche deployment technology rather than a scalable standalone power solution. First-of-a-kind estimates suggest current LCOE in the range of ~\$100–200/MWh, with potential reductions toward ~\$50–80/MWh by 2035 in favourable configurations, particularly where existing oil and gas wells or hybrid

storage applications can be leveraged. The economics are strongest when repurposing sunk infrastructure or pairing with solar as a long-duration storage substitute. However, its headroom is structurally constrained by well location, reservoir temperature and pre-existing well geometry. Unlike EGS, GGS does not unlock large new geographies at scale and therefore is unlikely to drive system-wide geothermal cost convergence independently. Its value is meaningful in specific contexts, but its scalability is inherently bounded. Sage’s HeatRoot approach is a gravity-assisted, vertical fracturing designed to create a network of fractures oriented outward and downward from the fracture point or well. Unlike more conventional horizontal fracturing approaches that operate at shallower depths and rely on the pressure of the injected fluid to create a series of upward propagating fractures, Sage’s HeatRoot system uses heavier, denser fracking fluids and Earth’s natural lithostatic pressure, which is the pressure created by the collective weight of the rocks overhead, to drive the process.

The primary headwinds for GGS are the significant geological constraints. A suitable site must possess pressure containment capabilities and must avoid the presence of faults to minimise induced seismicity risks. There is still a significant amount of uncertainty regarding subsurface characteristics at different sites, which will ultimately dictate the scope of geological suitability for the technology.

Advanced Closed-Loop (ACL) – also referred to as Advanced Geothermal Systems

ACL systems work based on heat conduction. ACL systems circulate a working fluid through sealed pipes installed deep underground. The system does not rely on natural permeability and does not fracture the formation. Heat transfers from the surrounding rock into the working fluid purely through conduction. The fluid remains confined within the pipe network and is recirculated in a closed loop at surface.

This design eliminates formation water loss and results in near-zero induced seismicity. However, because ACL depends solely on conductive heat transfer rather than convective flow through a permeable reservoir, power density is structurally lower. Output per well is typically 2–5 MW. Thermal drawdown or dissipation must also be managed by spacing well pairs and balanced flow geometry. Both are required to prevent localised cooling of the surrounding rock, which would reduce efficiency over time.

Eavor, a Canadian company headquartered in Calgary, is the leading ACL developer. Its Geretsried project in Bavaria, Germany consists of two ~4.5 km vertical wells connected by twenty-four 3.5 km lateral wells per loop, forming a large subsurface heat exchange network (the Eavor-Loop™). The project delivered its first electricity to the grid in December 2025, initially producing ~0.5 MW and targeting ~8.2 MWe and 64 MWth in Phase 1 combined heat and power. Earlier, the Eavor-Lite pilot in Alberta, Canada validated the company's core circulation design, in which fluid moves through the loop without pumping, driven by temperature and pressure differences alone, with model accuracy within ~2% and stable multi-year operation.

XGS Energy is developing a related closed-loop system using Thermal Reach Enhancement to improve heat transfer in a water-independent design. As of September 2025, XGS achieved over 3,000 hours of continuous operation at the Coso Geothermal Field, validating >70°C temperature differentials and model accuracy within ~2%. The company has announced a phased 150 MW partnership with Meta Platforms in New Mexico and continues to build out its commercial pipeline.

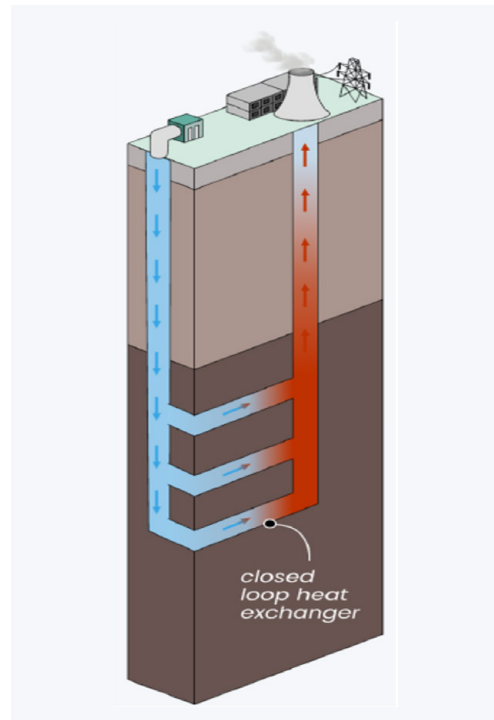
ACL platforms therefore demonstrate technical credibility, but large-scale commercial deployment remains earlier stage relative to leading Enhanced Geothermal Systems developers. Its principal constraint is lower output intensity relative to fracture-based systems, which may limit

its competitiveness for large-scale utility applications unless drilling and heat-transfer efficiencies improve materially.

ACL benefits from minimal seismic risk and has regulatory advantages in certain jurisdictions, particularly parts of Europe. However, the economics are challenging. To compensate for lower heat-transfer efficiency, developers must drill very deep wells with long laterals to increase surface area, materially increasing capital intensity. The need for deeper drilling to achieve adequate heat exchange makes cost competitiveness more difficult relative to EGS, particularly in high-cost drilling environments. As a result, ACL is likely to remain more geographically selective and may scale more slowly than fracture-based systems.

Exhibit 26

Advanced Closed-Loop (ACL)



Source: Ember (2025)

Super-Hot Rock Geothermal (SHR)

SHR technology targets ultra-high temperature resources above 374°C, where water enters a supercritical state and carries materially higher energy density than conventional geothermal fluids. These conditions can be reached at depths as shallow as 2–3 km in high-gradient volcanic settings (Larderello, Krafla, Newberry), but require depths of 5 km or more in lower-gradient continental basins. At such temperatures, conventional mechanical drilling equipment suffers rapid bit wear and casing degradation, though as the data below shows, every super-hot well drilled to date has used conventional methods. Advanced drilling technologies aim to extend bit life and reduce well cost rather than reach temperatures that conventional drilling cannot.

Emerging SHR drilling approaches include plasma drilling and millimetre-wave drilling, the latter using high-frequency electromagnetic energy to vaporise rock without physical contact. By eliminating drill bit wear and reducing mechanical stress, these methods aim to make ultra-deep, ultra-hot resources technically and economically accessible. Under supercritical conditions, each well could theoretically produce 5–10x the energy output of a conventional geothermal well, materially increasing power density per site, and lowering the cost/MWh.

SHR offers the highest theoretical upside within Next-Generation Geothermal due to its materially greater power density per well. However, fully supercritical SHR remains at an early technical stage and depends on the successful commercialisation of advanced ultra-high-temperature drilling technologies. As a result, supercritical SHR is the least mature pathway and carries the highest technical and execution risk for investors — although, as the data below shows, leading EGS developers are already operating at temperatures that were until recently considered SHR territory. With a Technology Readiness Level of approximately 4–5, it remains at the prototype stage.

Critically, the relationship between temperature and well economics is continuous rather than a step at 374°C, but it does steepen materially as temperatures rise. Output per well grows broadly linearly with bottom-hole temperature across the conventional and EGS range, from ~5–7 MWe at hydrothermal temperatures (200–250°C) to ~10 MWe at the commercial EGS frontier today (Fervo at 288°C, Mazama at 331°C). Above ~350°C, the curve turns sharply upward as fluids transition toward supercritical behaviour. Water becomes denser, carries more energy per unit mass, and flows more freely, pushing output per well toward 20–30 MWe at fully supercritical conditions (>374°C). Crossing 374°C is therefore not an economic cliff that has to be cleared in one jump. Every incremental 20–30°C of temperature improvement raises energy yield per well and reduces wells-per-MW, with the steepest gains reserved for projects that approach the supercritical band. Projects that extend EGS into the 290–350°C “near-supercritical” range still capture a meaningful share of the SHR economic prize, with the full prize reserved for those that cross into supercritical operation.

Commercial deployment depends not on incremental optimisation, but on the maturation of an entire ecosystem of enabling technologies — ultra-high-temperature drilling tools, advanced materials, downhole electronics and measurement, high-temperature casing, surface power systems and well control equipment capable of operating reliably above 374°C. While supercritical resources could ultimately deliver materially higher power density per well and significantly lower long-term LCOE, SHR is still materially distant from commercial deployment. It is best understood as the long-term destination of geothermal innovation rather than a near- or medium-term driver of market growth. From an investment perspective, SHR offers asymmetric upside but carries substantial technical, execution and timing risk relative to EGS.

Quaise Energy and Mazama Energy are the leading SHR start-ups, both targeting the Newberry Volcano in Oregon, where unusually high thermal gradients enable access to temperatures exceeding 400°C at depths below 5 km. Mazama recorded a 331°C bottomhole temperature in 2025 — the hottest EGS pilot to date — and, with backing from U.S. Department of Energy funding and Khosla Ventures, plans to scale to a 15 MW pilot in 2026, positioning SHR as a high-potential but early-stage pathway within Next-Generation Geothermal.

Quaise is using this same site to test its millimetre-wave drilling technology, designed to vaporise rock and access super-deep geothermal heat sources. According to Quaise’s CEO Carlos Araque, drawing on his latest project timeline and DOE documentation, the Newberry well demonstration is expected to achieve sustained flow rates before the end of 2026 from this subcritical site which is 4-5km deep, with an expected temperature of 200°C, producing 25–30 MW equivalent. This test represents one of the first real-world validations of superdeep geothermal drilling that could, if successful, expand geothermal deployment to nearly any region globally. This project is the first step toward a 2027–2028 pilot for supercritical (>400°C) high-

enthalpy geothermal electricity generation. When it does come to much deeper drilling, Carlos Araque highlights that consistency is more important than metres drilled/hour given the cost of unproductive time, starting and stopping drilling, at these depths. He anecdotally mentioned that a Chinese drilling experiment took a year to drill down 10 km, and another year to drill the 11th km.

To frame how close the industry is to commercial Super-Hot Rock production, it is worth surveying super-hot well experience across three dimensions: where leading NGG developers are operating today, the broader universe of historical super-hot geothermal wells drilled over the past four decades, and the closest oil & gas analogues. Two thresholds matter and they differ by domain. In geothermal, the relevant threshold is 374°C, the critical temperature of pure water above which fluids enter a supercritical phase carrying materially higher energy density per unit mass. In oil & gas, the conventional definition is HPHT at $\geq 150^\circ\text{C}$ bottomhole temperature with $\geq 10,000$ psi pressure, with “ultra-HPHT” at $\geq 205^\circ\text{C}$. The two categories are separated by roughly 175°C — precisely the band where standard downhole electronics fail and where the picks-and-shovels investment opportunity discussed earlier in this paper sits.

Exhibit 27a

Bottomhole temperatures reached by leading Next-Generation Geothermal developers and reference projects

Company / Project	Temperature reached	Location	Date	Well type	Implication for SHR
Mazama Energy	331°C	Newberry Volcano, Oregon	2025	EGS pilot	Hottest EGS pilot on record; within ~43°C of supercritical threshold
Fervo Energy	290°C projected; 185–218°C commercial	Cape Station, Utah	Observation well June 2025; disclosed April 2026 S-1	Deep vertical observation well 4.8 km; commercial production wells operating at 185–218°C	Demonstrates EGS appraisal viability into the 250–290°C band; commercial production still 85°C below supercritical
Quaise Energy	Target 200°C (2026); target >400°C (2027–28)	Newberry Volcano, Oregon	2026–28 planned	Millimetre-wave drilling demo, then supercritical pilot	Direct path to supercritical if mm-wave drilling proves out
Pertamina, Star Energy, Supreme Energy	250–300°C routinely	Wayang Windu, Salak, Darajat, Kamojang (Indonesia)	Commercial since 1980s–90s	Commercial hydrothermal	Industry already handles SHR-adjacent temperatures using adapted off-the-shelf tools
Iceland Deep Drilling Project-1	452°C wellhead	Krafla, Iceland	2009	Research; terminated on intersecting magma at 2.1 km	Confirms supercritical fluids exist at drillable depth in volcanic settings
Iceland Deep Drilling Project -2	426–427°C	Reykjanes, Iceland	2017	Research well to 4.66 km	Successful supercritical well completion at depth

Source: Company disclosures, DOE documentation, IDDP project reports, TNI analysis

Beyond these reference projects, a wider universe of geothermal wells has reached super-hot conditions ($\geq 375^\circ\text{C}$) over the past four decades — predominantly within existing producing fields where operators sought to characterise the deep heat source rather than develop the resource commercially. In every case, super-hot temperatures were reached using conventional mechanical drilling: three-cone bits, PDC bits with mud cooling, occasionally diamond coring. The practical limiting factor has consistently been bit life and casing/cement integrity rather

than drilling physics. Prati State 32 at The Geysers exhausted its final bit after only ~30 m at 400°C ; IDDP-1 flowed superheated steam at 452°C wellhead for 16 months before casing failures forced abandonment. The binding engineering constraint at depth is not temperature but the Brittle–Ductile Transition zone — visible in Kakkonda WD-1a at 380°C / 3,100 m — below which hydraulic stimulation becomes ineffective, and developers will likely need advanced closed-loop architectures rather than EGS-style engineered reservoirs.

Exhibit 27b**Historical super-hot geothermal wells ($\geq 375^{\circ}\text{C}$, excluding NGG developers)**

Well / Project	Operator	Location	Year	Depth (km)	Max temp ($^{\circ}\text{C}$)	Notes
Venelle-2 (DESCRAMBLE)	Enel Green Power / EU H2020	Larderello, Italy	2017–18	2.9	507–517	Hottest geothermal well on record; no exploitable reservoir confirmed
Kakkonda WD-1a	NEDO	Kakkonda, Japan	1994–95	3.73	500–510	Deepest geothermal well in Japan; brittle-ductile transition observed at 380°C / 3,100 m
Los Humeros (multiple)	CFE / GEMex	Puebla, Mexico	1988–2008	up to ~3.0	up to 423	Six wells drilled to characterise deep heat source at producing field
San Vito-1	AGIP	Campi Flegrei, Italy	1980	n/a	419	Early super-hot exploration in volcanic caldera
Prati State 32	Calpine	The Geysers, USA	2010s	2.7	~400	Final drill bit lasted only ~30 m, illustrating tool degradation at SHR temperatures
Menengai (3 wells)	GDC	Menengai, Kenya	2011+	various	~400	Three wells reached SHR conditions; some encountered shallow magma
Nisyros-1	PPC Greece	Nisyros, Greece	1982	n/a	400	Volcanic-arc super-hot exploration well; not developed commercially
IID-14	Imperial Irrigation District	Salton Sea, USA	1990	n/a	390	Reached SHR conditions below the productive zone exploited commercially today
San Pompeo-2	Enel	Larderello, Italy	early 1980s	n/a	>375	First well to confirm supercritical-relevant temperatures beneath Larderello

Source: Company disclosures, DOE documentation, IDDP project reports, TNI analysis

By contrast, the closest oil & gas analogues operate at temperatures roughly 175°C below the geothermal SHR threshold. The Haynesville Shale is the hottest commercially producing O&G play and the most relevant

temperature reference; the Sakhalin-1 and Kola wells are included as scale references — they are the deepest holes ever drilled but their bottomhole temperatures are well below SHR.

Exhibit 27c

Oil & gas reference points — HPHT and ultra-deep wells

Well / Project	Operator	Location	Year	Depth (km)	Max temp (°C)	Notes
Haynesville Shale (representative)	Various (Comstock, Aethon, Expand Energy)	Texas / Louisiana, USA	ongoing	3.0–4.3 TVD	150–195	Hottest shale gas play in commercial production; closest O&G analogue to NGG temperature conditions
Z-44 Chayvo (Sakhalin-1)	ExxonMobil / Rosneft	Chayvo field, Sakhalin Island, Russia	2012	12.38 MD	<100	Held world record for measured depth on completion; sedimentary-basin oil well, well below SHR temperature
O-14 / Orlan platform (Sakhalin-1)	ExxonMobil / Rosneft	Chayvo field, Sakhalin Island, Russia	2015 / 2017	13.5–15.0 MD	<100	Subsequent extended-reach drilling records; same caveat
Kola Superdeep Borehole	USSR / Kola Science Centre	Kola Peninsula, Russia	1989	12.26 TVD	180	Deepest borehole ever drilled. Bottomhole temperature only 180°C — depth does not equal super-hot when the local gradient is low

Source: Company disclosures, DOE documentation, IDDP project reports, TNI analysis

Taken together, these data points suggest that the EGS–SHR boundary is narrowing faster than TRL classifications suggest. The leading indicator is whether Fervo (or any successor) extends commercial production above 300°C in the next 24 months — a threshold that would compress the narrative gap between EGS and SHR materially. We continue to allocate SHR to the futuristic vertical for now.

Commercial deployment of supercritical-temperature electricity generation still depends on unproven drilling, materials and surface systems. We flag this convergence as a factor to watch. The more likely near-term trajectory is progressive EGS temperature extension into the 290–350°C range, rather than a discrete leap to fully supercritical operation.

Exhibit 28

Contrasting Mazama vs Quaise SHR Technology

Feature	Mazama	Quaise
Method	Hybrid Mechanical for handling hot rock	Millimetre-wave energy
Origin	Oil & gas drilling evolution	Fusion technology (gyrotrons)
Depth potential	Moderate (5–10 km typical)	Very deep (15–20 km+)
Temperature tolerance	Limited by materials	Extremely high
Maturity	Closer to commercialisation	Early-stage / experimental
Risk level	Lower	Higher

Source: TNI Analysis

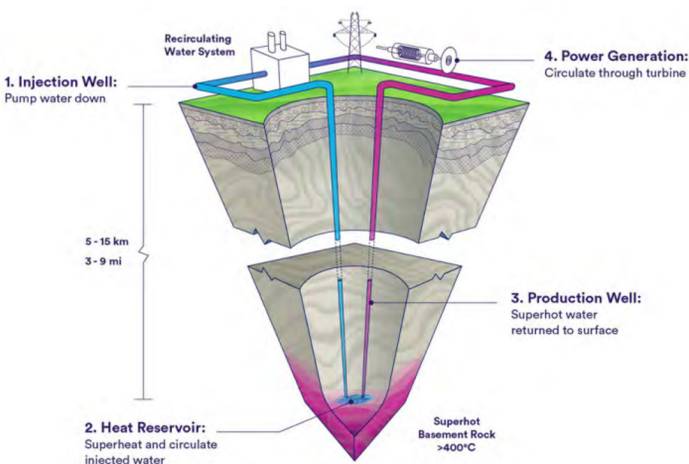
The exhibit below illustrates SHR well architecture: injection and production wells extending 5–15 km into basement rock exceeding 400°C, where water reaches supercritical conditions before returning to the surface for power generation. This is the configuration Mazama Energy is working toward at Newberry Volcano. It is structurally similar to EGS but requires wells roughly twice as deep and drilling technology capable of withstanding temperatures far beyond the limits of current commercial equipment.

These four technologies constitute Next-Generation Geothermal technologies. Qualitatively, EGS appears to have the greatest potential and momentum. Ormat's endorsement of Sage and GGS suggests there is potentially a viable technology there and the long-term breakthrough really sits with SHR. Exhibit 30 summarises the qualitative aspects of each technology and gives you a sneak preview of our cost (LCOE) analysis conclusions, which again favour EGS. The next chapter lays out the LCOE analysis.

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Exhibit 29

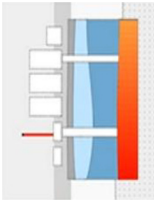
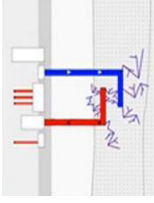
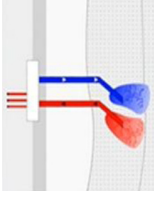
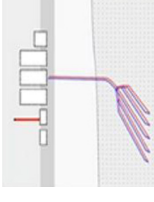
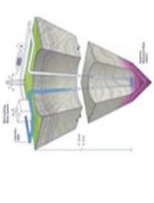
Super-Hot Rock (SHR)



Source: CATF (2026)

Exhibit 30

EGS appears to win out over all Next-Generation Geothermal technologies

Aspect	Conventional (Hydrothermal Reservoir Dependent)	Enhanced Geothermal Systems (EGS)	Geopressured Geothermal System (GGS)	Advanced Closed-Loop (ACL)	Super-Hot Rock
Technology	Taps naturally hot, pressurised, and permeable reservoirs to generate heat and power.	Engineered flow paths between wells, allowing fluid circulation without natural permeability.	"Huff-and-Puff" method injects fluid into fractures, heats in place, then recovers it.	Advanced Closed-Loop system circulates a working fluid to extract heat without reservoir interaction.	Taps ultra-high temperatures, typically at greater depths, for exponentially greater power.
Availability	Limited Dependent on heat, permeable, and fluid (~3% of earth's surface)	Dependent on subsurface heat; but expanded beyond conventional	Dependent on subsurface heat but expanded	Dependent on subsurface heat but expanded	Supercritical (374°C) Anywhere Accesses Universal Heat from Earth's core
Temp	300°C or less	374-600+°C			
Depth	1-3.5km	2-7km	2-5km	1-5km	5km+
Current LCOE	\$70/MWh	>\$90/MWh	>\$100-200/MWh (FOAK est.)	>\$150-250/MWh (FOAK est.)	>\$300/MWh (FOAK est.)
Output / well	5-7 MWe	5-10 MWe	5-10 MWe	2-5 MWe	20-30 MWe (NOAK)
TR Technology Maturity Level	9 (Mature)	7 (Demonstration)	Baseload: 4-5 (Prototype) Storage 7 (Demonstration)	5-6 (Large Scale Prototype)	4-5 (Prototype)
Risks	- Exploration risk Resource depletion	- Induced seismicity from fracturing - Management of artificial fractures	- Low well cooling - Thermal management of artificial fractures and reservoir	- High drilling cost to achieve surface area - Low rock conductivity limits energy output	- Costs and feasibility of drilling in extreme depths and temperatures
Leading Developers	Ormat, Enel Green Power, Calpine	Fervo Energy	Sage Geosystems	Eavor, XGS Energy, GreenFire Energy	Mazama Energy Quaise
Image					

Are there significant advancements in O&G drilling technology that could help to more effectively exploit the geothermal opportunity?

Today, oil and gas companies overwhelmingly (95%+) rely on mechanical rotary drilling, the same fundamental approach that has powered the industry for decades but now executed with highly sophisticated equipment and digital control. Operators use advanced drill bits (especially PDC—polycrystalline diamond compact), steerable systems, and downhole motors to cut through rock while circulating drilling fluid to manage pressure and remove cuttings. While a small share of wells incorporate percussion (hammer) drilling in especially hard formations, and a handful of pilot projects test water jets, plasma pulses, or electromagnetic (laser/millimetre-wave) methods, these alternatives collectively represent only a tiny fraction of activity. In practice, they are not yet replacements but experimental or hybrid enhancements. Looking ahead, plasma/electric pulse systems may begin to take modest share as assist technologies in hard rock, while laser or millimetre-wave drilling—as pursued by Quaise Energy—has the most transformative potential long term, particularly for ultra-deep geothermal wells. However, for the foreseeable future, mechanical drilling will remain dominant due to its reliability, cost efficiency, and global infrastructure.

At the same time, mechanical drilling itself continues to improve in meaningful ways rather than standing still. Advances in drill bit materials—notably more durable and thermally stable diamond composites—are extending bit life and performance in abrasive formations. Downhole motors and rotary steerable systems have become more precise, enabling faster and more accurate directional drilling with fewer interruptions. Improvements in high-temperature electronics and materials are pushing operational limits deeper and hotter, which is especially important for geothermal crossover applications. Additionally, smarter drilling fluids, real-time sensing, and automation are reducing wear, improving rate of penetration, and minimising downtime. Taken together, these incremental innovations are steadily expanding the envelope of what mechanical drilling can achieve, making it a moving target for any alternative technology attempting to displace it.

Somewhat surprisingly, the technologies cited as of potential value in future for oil & gas appear to be primarily those being explored for geothermal drilling including plasma drilling, largely being developed by GA Drilling who has been in business since 1994 and millimetre-wave drilling, solely being developed by Quaise, who has been in business since 2018, when it spun out from MIT Plasma Science and Fusion Center.

Exhibit 31**Drill Bit Technology Developments – those for Geothermal are the same as for O&G**

Feature	Mechanical Drilling	Plasma Drilling	Millimetre-Wave Drilling	ERS (Electrical Reservoir Stimulation)
Basic Method	Physical rotation + drill bit cuts rock	Plasma arc or electrical discharge heats rock	Focused electromagnetic energy (laser or mm-wave) vaporises rock	High-voltage pulsed electrical energy creates fractures in rock
How Rock Breaks	Crushing, scraping, grinding	Thermal shock, melting, fracturing	Direct vaporisation / spallation	Electrical breakdown and tensile fracturing; self-propelled fracture networks
Tool Contact	Full contact	Minimal / none	None	Minimal (electrode contact in borehole)
Temperature Range	Limited by materials (~200–350°C typical)	~5,000–20,000°C	Can exceed rock vaporisation temps (~2,000–5,000°C+)	Operates in ambient to >400°C reservoirs (lab to >330°C tested)
Depth Potential	Moderate (5–10 km typical)	High (theoretical 10–20 km)	Very high (15–20+ km target)	High (5–20+ km target)
Wear & Tear	High (bit replacement frequent)	Low (no bit)	Very low (no bit)	Very low (no bit; electrodes long-life)
Energy Use	Moderate	Very high	Extremely high	High (pulsed; energy efficient per volume fractured)
Speed in Hard Rock	Slowest in very hard rock	Potentially faster than mechanical	Potentially fastest	Fast fracture creation, then circulation
Maturity Level	Fully commercial	Early-stage / pilot - TRL 4–6	Experimental / cutting-edge-TRL 3–4	Early commercial / pilot - TRL 6
Main Challenge	Tool wear + heat limits	Controlling plasma + energy delivery	Power delivery + efficiency at depth	Energy delivery, scaling fracture networks, reservoir characterisation
Users	All O&G and all Geothermal	GA Drilling, O&G R&D	Quaise	Eden Geopower, Geothermal (EGS), Mining, Hydrogen

Source: TNi analysis

Yet another rock penetration technology being developed for oil & gas and geothermal drilling applications is electrical reservoir stimulation or ERS. ERS is an emerging non-hydraulic rock penetration and reservoir enhancement technology that uses high-voltage pulsed electrical energy to create dense, self-propped fracture networks in hard subsurface formations. Unlike conventional hydraulic fracturing, ERS does not require water, chemical additives, or proppants, and is designed to minimize induced seismicity while significantly increasing rock permeability and heat-transfer efficiency. ERS is currently best described as TRL 6 (Technology Readiness Level 6) for geothermal applications. The technology has demonstrated laboratory-validated permeability improvements of up to 1,000% in hard rock formations and has shown commercial relevance through a 130% oil production uplift in a Petroleum Development Oman field pilot.

As an MIT spinout founded in 2017, Eden GeoPower is pioneering the commercialization of ERS across geothermal energy, oil and gas restimulation, mining, and geologic hydrogen applications. Eden's strategic advantage lies in its ability to reduce well stimulation costs by roughly 80% relative to hydraulic fracturing. Through partnerships with organizations such as Mazama Energy, Utah FORGE, and ARPA-E, Eden is advancing a staged commercialization pathway toward super-hot rock geothermal systems, with planned demonstrations progressing from 225°C reservoirs at Utah FORGE to 330°C projects at Newberry and ultimately to >375°C systems in the Salton Sea region by 2029. Eden is profiled in the appendix.

6. What LCOE do next-generation technologies need to reach to be competitive with natural gas produced electricity?

In most developed power markets, natural gas effectively sets the marginal price of baseload electricity, making it the relevant benchmark against which geothermal must compete. Because gas-fired generation costs are dominated by fuel, this benchmark is not static; the implied clearing price of electricity moves directly with gas prices. Competitiveness for geothermal is therefore not defined by undercutting gas at a single point in time, but by achieving an LCOE that holds across the range of gas price outcomes observed over a cycle. In practice, this implies a required LCOE of approximately \$60–70/MWh in the US and \$120–130/MWh in Europe, reflecting the structurally higher and more volatile gas price environment in Europe.

Approximately 60% of CCGT LCOE is driven by fuel costs, and wholesale electricity prices track gas prices closely in both markets. In the US, each \$1/MMBtu move in Henry Hub translates to approximately \$6–7/MWh in wholesale electricity. In Europe the pass-through is larger, reflecting a higher share of gas in the generation mix. This dynamic has been stark in practice: annual average European wholesale electricity ranged from

\$34/MWh in 2020 to over \$240/MWh at the peak of the 2022 supply crisis — a more than seven-fold swing within three years. Exhibit 32 plots each year’s average wholesale electricity price (y-axis) against the natural gas commodity traded price (x-axis) to show both the direct link between the two and how much variability the changing gas price has which in turn creates variability in electricity prices.

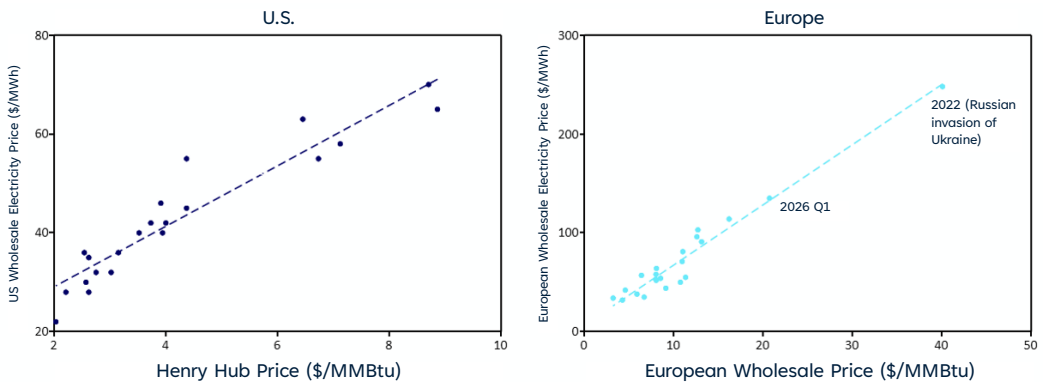
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Exhibit 32

Wholesale electricity prices (y-axis) are closely linked to natural gas prices (x-axis)

Natural gas price vs. wholesale electricity price, 2005–2026 Q1

USD/MMBtu; USD/MWh



Source: EIA; IMF Primary Commodity Prices via FRED; EEX; ENTSO-E Transparency Platform; ECB/Federal Reserve H.10.

Notes:

- (1) All figures are annual averages in nominal terms, pre-subsidy, pre-carbon cost, and exclude transmission, distribution, and retail margins.
- (2) US wholesale electricity is a composite of major hub prices (principally PJM West and ERCOT North); regional prices vary materially.
- (3) European wholesale electricity uses German EEX baseload as a proxy for 2005–2014, switching to a pan-European ENTSO-E average from 2015.
- (4) Trend lines fitted by ordinary least squares regression. (5) 2026e is a partial-year estimate.

Henry Hub has ranged from \$2/MMBtu to \$9/MMBtu over the past two decades, a more than four-fold swing. European gas prices have been structurally higher throughout, peaking at an annual average of approximately \$40/MMBtu in 2022 following post-Ukraine war supply disruptions vs under \$4/MMBtu just two years earlier, during Covid. Supply risk

remains structurally embedded: the partial closure of the Strait of Hormuz in early 2026, a route accounting for approximately 20% of global LNG trade, has already driven price increases in Europe. European TTF gas, which averaged \$11/MMBtu in January to February 2026, rose to a monthly average of \$18/MMBtu in March 2026.

Exhibit 33

Gas prices are highly volatile and exposed to geopolitical shocks

Annual average natural gas prices, US (Henry Hub) and Europe (EU border), 2000–2026 Q1
USD/MMBtu



Source: EIA (AHHNGSP), IMF (PNGASEUUSDA) via FRED

Notes:

- (1) Annual average spot prices. 2026 values reflect year-to-date average as of April 2026.
- (2) European 2026 figure reflects elevated gas prices following the Strait of Hormuz disruption (March 2026).

Exhibits 34 and 35 set out the LCOE of new-build gas CCGT across major forecast sources. US estimates cluster around \$60–70/MWh, with our point estimate at \$70/MWh

through 2035. European estimates are materially higher and more dispersed, driven by structurally elevated fuel costs and carbon exposure; our point estimate is \$130/MWh.

Exhibit 34

U.S. Gas CCGT forecasts point to a ~\$60–70/MWh competitiveness benchmark, prices no different than current prices

Source	Current LCOE 2025 (\$/MWh)	Future LCOE (\$/MWh)	Year	Key Notes
U.S. BNEF (2026)	66	65	2035	
U.S. EIA (2025)	65-67	—	2030 COD	New plants entering service in 2030
U.S. Lazard (2025)	48-109	—	-	Illustrative range; high case assumes elevated CAPEX for post-2028 COD
U.S. IEA WEO (2024)	80	130	2030	Includes retrofits and policy assumptions; not a pure cost forecast
TNI Point Estimate	70	70	2035	Mid-point of Lazard; slightly above BNEF and IEA

Exhibit 35

European Gas CCGT forecasts point to a ~\$120–130/MWh competitiveness benchmark, prices little different than current prices

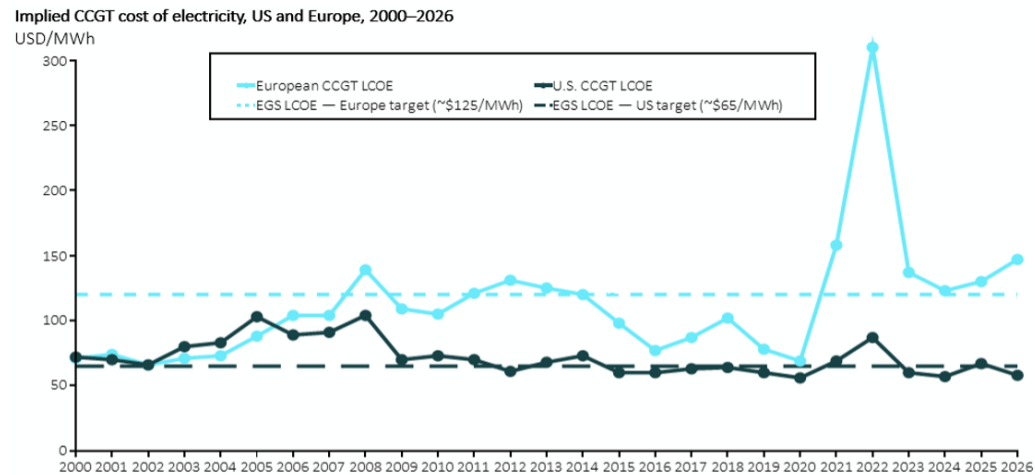
Source	Geography	Current LCOE 2025 (\$/MWh)	Future LCOE (\$/MWh)	Year	Key Notes
BNEF (2026)	Germany	158	158	2035	
Fraunhofer ISE (2024)	Germany	104-184	123-212	2035	Includes heat credits
IEA WEO (2024)	EU	175	185	2030	Includes retrofits and policy assumptions
UK Gov DESNZ (2025)	UK	135	—	—	Excludes carbon tax; assumes 30% capacity factor
TNI Point Estimate	Europe	130	130	2035	Lower end of wide-ranging estimates, based on analysis of historic MMBtu pricing

Translating these gas commodity prices directly into CCGT LCOEs, Exhibit 36 shows that the US implied cost of gas-fired electricity ranged from approximately \$39/MWh to \$87/MWh over the period — straddling the EGS target of ~\$65/MWh in both directions depending on the year. European CCGT LCOE

was structurally higher throughout and, in 2022, briefly exceeded \$290/MWh. Critically, the EGS Europe target of ~\$125/MWh has been exceeded by gas-fired generation for the majority of years since 2010, underlining the scale of the addressable market if EGS can reach that cost level consistently.

Exhibit 36

Indicative CCGT LCOE derived from gas prices, US and Europe, 2000–2025



Source: EIA (Henry Hub); BP Statistical Review / ICE TTF (EU border); Lazard LCOE+ (June 2025).

Notes:

(1) All figures are wholesale electricity costs, pre-subsidy, and exclude transmission, distribution, and retail margins.

(2) Implied cost of new-build gas-fired electricity, calculated as the regional gas benchmark (Henry Hub for the US; EU border/TTF for Europe), plus estimated non-fuel operating costs (US: ~\$20/MWh; Europe: ~\$25/MWh), plus ~\$17/MWh levelised capital cost for new-build CCGT (Lazard LCOE+ June 2025).

(3) EGS target lines reflect full LCOE including capital costs and are directly comparable.

(4) 2026 European value reflects elevated gas prices following the Strait of Hormuz disruption (March 2026).

Geothermal, by contrast, is capital-intensive but fuel-free. Once built, it offers stable and predictable generation with long-term contracted pricing and minimal marginal cost risk. This price certainty carries strategic value for utilities, grid operators and corporate off-takers, particularly data centres and industrial customers seeking 24/7 clean power with limited exposure to fuel volatility.

Market behaviour already reflects this dynamic. In the United States, EGS developers have secured long-term PPAs in the \$90–100/MWh range, despite gas appearing cheaper on a short-run LCOE basis. Google has signed an offtake agreement with Fervo at its pilot EGS facility in Humboldt County, Nevada for \$107/MWh. Buyers appear willing to pay a premium for firm, carbon-free generation with long-term price stability and decarbonisation alignment.

7. Is EGS on a path to a competitive LCOE and what will drive its cost reduction?

EGS and Next-Generation Geothermal can achieve cost competitiveness through three primary and quantifiable drivers. First, increasing plant size from early 50 MW projects to 200 MW utility-scale developments reduces LCOE by ~\$14/MWh through spreading of fixed development, EPC and operating costs. Second, continued improvements in drilling performance, including higher site success rates, gains in drilling speed, and access to higher-temperature resources, all contributing to a further ~\$10/MWh reduction. Third, as projects demonstrate repeatable performance and transition to levered project finance structures, the weighted average cost of capital (WACC) declines from ~9% to ~6%, reducing LCOE by an additional ~\$11/MWh. Together, these mechanisms drive the modelled reduction in EGS costs from ~\$90/MWh today to ~\$55/MWh by 2035, but the trajectory is highly geography-dependent. The \$55/MWh outcome is achievable in regions with thermal gradients of 2–4× the global average — most notably the Western United States — and is most credible there. In Europe, where gradients are typically 20–30°C/km, achieving competitive electricity LCOE through EGS is materially more challenging and may not be achievable at scale on this time horizon. We therefore expect Europe to lead in geothermal-for-heat and CHP applications and to lag the US by 5–10 years in unsubsidised EGS-for-power economics — and possibly never reach parity in many sub-regions.

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A note on cost, LCOE, wholesale and retail prices: LCOE (levelized cost of energy) figures are used throughout this report to talk about the cost of geothermal electricity generation. LCOE is the all-in average cost to produce one megawatt-hour (MWh) of electricity over the lifetime of the plant. We will often compare our estimates of LCOE or cost to wholesale electricity prices to draw conclusions about competitiveness of geothermal generated electricity against that from natural gas. PPA are generally agreed in terms of wholesale offtake prices. For example, hyperscaler PPA prices were set at \$107/MWh between

Fervo and Google in Nevada. LCOE costs have no margin embedded, while obviously a wholesale price does. You will see and hear about much higher electricity prices in the US and elsewhere and these are not relevant to our LCOE vs wholesale electricity price comparison. US retail electricity prices for industrial customers average ~\$70-90/MWh per EIA 2025/26 data — approximately 30–50% higher than wholesale reference levels due to transmission, distribution and retail margin. US residential retail prices are higher still, averaging over \$170/MWh.

Exhibit 37

Ultimately, US geothermal must compete with the US wholesale power prices of \$40 – 50/MWh with a premium for firm clean energy

Price	Typical US Range (2025–2026)	Meaning
Wholesale power market price	\$40–50/MWh	Bulk electricity traded in ISO/RTO markets
Large industrial retail tariff	\$70–90/MWh	What big factories/data centres often actually pay
Commercial retail tariff	\$120–150/MWh	What offices/commercial buildings typically pay
Residential retail tariff	\$170–190/ MWh	What the average residential customer pays

Source: EIA Feb 2025 and Feb 2026

Across published forecasts, there is broad consensus that EGS costs decline materially over the next decade, with most estimates converging toward the \$50–70/MWh range by the mid-2030s. Current (2025) LCOE estimates span roughly \$75–100/MWh in mainstream techno-economic models such as NREL ATB and U.S. DOE analysis. Forward projections typically cluster around ~\$45–60/MWh by 2035 in the U.S., driven by faster drilling rates, higher well success rates, improved stimulation and flow performance, movement to larger utility-scale plants, and learning effects as projects transition from FOAK to NOAK. More optimistic cases incorporating tax credits and favourable financing assumptions fall toward the lower end of this range (mid-\$40s to low-\$50s), while conservative scenarios remain closer to \$70–80/MWh. Our TNI point estimate of ~\$90/MWh today declining to ~\$55/MWh by 2035 sits within the mainstream of institutional forecasts, anchored near the midpoint of current NREL ranges and slightly above the most aggressive DOE and McKinsey targets to reflect execution and scaling risk.

Our current cost estimate for EGS of \$90/MWh and our forecast of \$55/MWh are not

solely based on this range of expert forecasts (Exhibit 38), but rather our detailed, bottom-up analysis of current EGS costs and how those costs should be expected to change, largely with more experience in the full set of exploration to development phases over the next 10 years. Most components of the geothermal value chain are identical across traditional and next-generation systems. The surface power plant, grid interconnection, engineering, procurement and construction (EPC), and operational costs are largely unchanged regardless of the subsurface technology used.

The primary difference lies in the wellfield, which represents the main technical and economic distinction between hydrothermal and Next-Generation Geothermal systems. Next-generation technologies such as Enhanced Geothermal Systems (EGS) require deeper wells, longer horizontal laterals, and reservoir stimulation, increasing both drilling complexity and cost. By contrast, hydrothermal projects rely on naturally permeable reservoirs and therefore require shallower wells, dug in cooler environments with little or no stimulation.

Exhibit 38 Expert EGS forecasts imply material cost decline toward \$55/MWh by 2035

Source	Current LCOE (2025)	Future LCOE	Future LCOE year	Comments
NREL Annual Technology Baseline (ATB) (2024)	\$76-104	\$50-87	2040	R&D financial assumptions exclude tax credits and policy incentives; Deep EGS/Flash modelled; forecasts extend to 2050. Decline driven by reaching higher temperatures, advancements in drilling efficiency, improvements in drilling success rate with drilling rate of penetration (ROP) doubling, improvements in reservoir stimulation enhancing flow rates, increased plant capacity as operators move to larger utility-scale plants and learning curve effects in moving from FOAK to NOAK.
NREL Annual Technology Baseline (ATB) (2024) with tax credits/policy support	\$62-84	\$36-81	2040	Market financial assumptions include tax credits and policy incentives; Deep EGS/flash modelled; forecasts extend to 2050. Decline driven by reaching higher temperatures, advancements in drilling efficiency, improvements in drilling success rate with drilling rate of penetration (ROP) doubling, improvements in reservoir stimulation enhancing flow rates, increased plant capacity as operators move to larger utility-scale plants and learning curve effects in moving from FOAK to NOAK.
IEA (The Future of Geothermal Jan 2025)	\$240	\$50-120	2035	Forecast assumes drilling drives 60-80% of capex; cost reductions from oil and gas synergies, learning-by-doing and scale lower costs from ~\$14,000/kW FOAK to ~\$2,000-5,000/kW by 2050.
U.S. DOE (2024)	\$96-102	\$45	2035 (Target)	Improvements driven by faster drilling rates, increased exploration efficiency, increased flow rates, improved well stimulation and larger utility-scale plant sizes. Innovations since the 2035 target was set imply EGS is on track to meet that target.
McKinsey (2025) US	\$75	\$45	2035	Cost reductions driven by: reduced drilling and hydraulic fracturing cost, improved well productivity, optimised exploration spend through better mapping and characterisation of geological resources, and scaled supply chains for power plant equipment resulting in lower surface capital expenditures.
McKinsey (2025) US: with tax credits/policy support	\$60	\$40	2035	Cost reductions driven by: reduced drilling and hydraulic fracturing cost, improved well productivity, optimised exploration spend through better mapping and characterisation of geological resources, and scaled supply chains for power plant equipment resulting in lower surface capital expenditures.
Project InnerSpace & Future Ventures (2025)	\$88	\$50	2035	Modelled on a 1GW facility for data centres; capital recovery for developers of 9% and includes ITC benefit.
Pezzino et al. (Stanford) (2026)	\$150 (FOAK)	\$100 (NOAK)	NOAK	Gradient-weighted across the US leading to LCOE overestimate; estimate assumes reservoir temperatures of 200-299°C.
TNI Point Estimate	\$90	\$55	2035	Our current cost estimate sits in the middle of NREL ATB range. Forecast is set at the lower end of the NREL ATB range. While improvements in drilling ROP, well success rates, and flow rates could support more optimistic outcomes, costs are assumed slightly above the U.S. DOE target to reflect scaling and execution risks through 2035.

The expert forecasts summarised above cluster in a ~\$45–90/MWh range for EGS in 2035 in the US. However, practitioner views expressed — including Ormat CEO Doron Blachar publicly describing NGG as a ~\$200/MWh product today — sit materially higher than the consensus forecast view, reflecting scepticism that drilling productivity gains and plant scaling will deliver at the pace implied by the NREL ATB and McKinsey cost curves. We present the expert consensus as our base case but flag that the realised cost trajectory may be slower, particularly in the first-of-a-kind projects through the late 2020s. A downside sensitivity of \$100–\$120/MWh by 2035 would position EGS poorly against \$40–50/MWh wholesale electricity prices, assuming they hold steady in real terms between now and 2035.

Exhibit 39 presents our estimate of the current cost structure for a 50 MW enhanced geothermal system (EGS) project, based on a synthesis of NREL, Stanford and industry research, calibrated to observed cost indications from developers such as Fervo Energy and our own diligence on next-generation geothermal (NGG) companies. Our analysis arrives at an LCOE of approximately \$90/MWh, compared to around \$70/MWh for conventional hydrothermal geothermal, implying a ~\$20/MWh premium at today's stage of deployment. This premium is driven by more complex wellfield development and a higher cost of capital, as EGS remains a relatively new and not yet fully de-risked technology.

Exhibit 39

Illustrative cost breakdown of a 50 MW EGS geothermal plant; subsurface and EPC costs drive the majority of geothermal LCOE

Cost	Total (M)	LCOE (\$/MWh)	Components	Key LCOE drivers
A. Initial CAPEX	\$207M	\$72/MWh		
Development, Engineering, Site Control	\$5M	\$2	Resource assessment & feasibility studies; Permitting & environmental studies; Reservoir modelling & engineering design; Land acquisition or lease payments; Legal, consulting & development overhead	Exploration risk
Wellfield	\$60M	\$21	Production & injection well drilling; Well casing, cementing & completion; Wellfield piping & gathering systems; Pumps & wellhead equipment; Drilling mobilisation & testing	Well depth; Well temperature; Flow rate; Lateral length; Rock hardness
Interconnection	\$23M	\$8	Transmission line construction; Substation equipment & transformers; Grid connection fees & upgrades; Switchyard & protection systems	Distance to transmission line; Grid upgrade requirements
Power and other surface plant and EPC	\$112M	\$38	Turbine-generator & power block equipment; Heat exchangers & cooling systems; Balance-of-plant systems; Mechanical & electrical installation; EPC contractor costs, labour & construction management	Turbine-generator cost; EPC contractor margin

Cost	Total (M)	LCOE (\$/MWh)	Components	Key LCOE drivers
Other (insurance, contingency)	\$7M	\$3	Insurance during construction; Contingency not allocated to specific categories	Economies of scale
B. ITC Tax Credit (30% × 75% eligible CAPEX)	(\$42M)	(\$11)	IRC §48/48E investment tax credit at 90% resale value	Policy dependent; scheduled phase-down post-2032
C. Annual OPEX	\$7M/yr	\$29		
Wellfield O&M, plant maintenance, insurance, water, labour	\$8M	\$29	Wellfield operations & maintenance; Plant maintenance & spare parts; Insurance & administrative costs; Water supply & treatment; Labour & site management	Well productivity (flow rate, temperature); Reservoir decline rate; Workover frequency
LCOE		\$90/MWh		

Notes:

- (1) 50 MWe plant, 8 production wells at ~6.6 MW each, 87% capacity factor, 30-year operating life, 1.5% annual generation decline.
- (2) WACC of 9.0% (construction phase: 65% debt at 8%, 35% equity at 14%).
- (3) LCOE uses NPV-based Lazard methodology; \$/MWh figures for CAPEX, OPEX and ITC = NPV of each cost category ÷ NPV of lifetime generation.
- (4) CAPEX sub-category \$/MWh figures are allocated pro-rata based on each sub-category's share of total initial CAPEX (\$207M) applied against the aggregate CAPEX LCOE contribution of \$72/MWh.
- (5) CAPEX is initial construction only; excludes renovation CAPEX.
- (6) ITC assumes 30% credit on 75% eligible CAPEX at 90% transferability.
- (7) Opex estimates are derived from TNI due diligence exercises on specific geothermal companies.

The cost of an EGS project is concentrated in two categories. Wellfield and Procurement & EPC together contribute ~\$59/MWh and therefore drive overall economics:

- Wellfield (\$21/MWh; 29% of CAPEX): drilling, casing, stimulation and completion of production and injection wells. Costs are driven by depth, temperature, flow rates and rock conditions.
- Power, other surface plant & EPC (\$38/MWh; 54% of CAPEX): turbine-generator, power block and plant construction. Costs are structurally similar to hydrothermal but remain elevated at smaller scale.

Proof of 30-year operating life assumption used in LCOE calculations.

The 30-year operating life assumption used in the LCOE calculations is supported by extensive empirical evidence from both hydrothermal geothermal systems and emerging EGS developments. Modern hydrothermal wells commonly operate for 30 years or more, with some European systems

exceeding 35 years under effective reinjection and pressure management, while major fields such as The Geysers have sustained production since the 1960s through ongoing well replacement and reservoir management. This demonstrates that geothermal behaves less like a depleting extractive resource and more like a managed thermal system whose longevity depends on operational practices. For EGS, the authoritative MIT study *The Future of Geothermal Energy* concludes that engineered reservoirs can similarly sustain commercial output for 30+ years if circulation pathways, fracture design, and thermal management are properly maintained. While EGS lifetimes are more dependent on engineering control than natural reservoir properties, the current scientific consensus is that both hydrothermal and EGS systems are capable of 30–50+ year operating lives when actively managed as long-term thermal reservoirs.

Other components are secondary. Development and interconnection add costs of ~\$10/MWh. The U.S. investment

tax credit reduces LCOE by ~\$11/MWh, and OPEX contributes ~\$29/MWh on an NPV basis over the asset life.

OPEX contributes approximately ~\$29/MWh on a lifecycle NPV basis and is a material component of total system cost. It includes wellfield operations and monitoring, workovers and pump replacement, surface plant maintenance, water management, labour, insurance, and recurring payments such as land leases and royalties. These costs scale broadly with the size of the wellfield and plant, and are not expected to decline materially over time, as they are driven primarily by labour, parts, and ongoing field operations. While performance still matters, with declining wells requiring more frequent interventions (e.g. restimulation and workovers), OPEX offers limited scope for structural cost reduction relative to CAPEX.

Together, these components result in an LCOE of approximately \$90/MWh today. The key question is how this cost declines over time. Our analysis identifies three primary drivers of cost reduction:

- A. Plant Size (~\$14/MWh by 2035): Economies of multi-well platform scale: Commercial projects expand from ~50 MW demonstration plants (8 wells) to ~200 MW utility-scale facilities (~25–30 wells), allowing fixed infrastructure costs (grid interconnection, surface facilities, development overhead) to be spread across materially larger generation capacity.
- B. Improved drilling performance and site de-risking (~\$10/MWh by 2035): EGS uses substantially the same drilling and hydraulic stimulation equipment as shale gas, and is expected to follow

a similar learning curve — shale well costs fell dramatically within a decade of commercialisation as operators standardised designs, increased drilling speeds and amortised early dry hole costs across expanding programmes. We model cost reductions from three sources: higher well success rates (74% to 83%) - driven by both industry maturation, as operators replicate proven well designs across additional wells on a de-risked site, and by AI-driven subsurface characterisation (e.g., Zanskar, Ignis Energy) reducing dry-hole risk on the first wells - reducing capital lost to dry wells; rising bottom-hole temperatures (toward ~320°C) improving output per well; and rate of penetration gains (520 to 1,200 ft/day) reducing rig days.

- C. Lower cost of capital (~\$11/MWh by 2035): As subsurface and execution risks decline, projects transition from equity-heavy development structures toward greater use of non-recourse project finance. This shift increases leverage and reduces both the cost of debt and cost of equity, driving a reduction in WACC from approximately 9% to 6%, materially lowering levelised cost of energy.

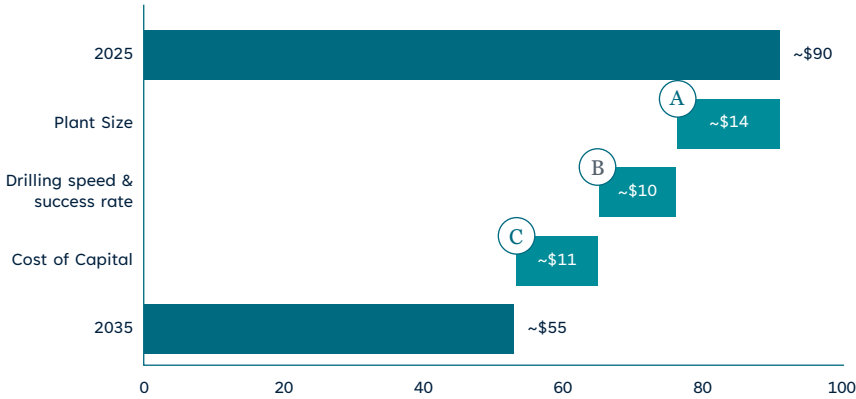
Together, these three mechanisms drive the projected ~\$35/MWh reduction in EGS costs from ~\$90/MWh today to ~\$55/MWh by 2035.

There are three major risks for EGS developers achieving this cost reduction trajectory: water loss, heat dissipation and reservoir restimulation. We discuss these in more detail in the technology chapter above. Any investment in a NGG developer must underwrite for these risks.

Exhibit 40

Scale, drilling gains and reduced WACC drive EGS LCOE from ~\$90 to ~\$55/MWh by 2035

Forecast reduction in EGS LCOE
USD / MWh



Source: TNI analysis

Notes:

(1) Plant size (~\$14/MWh): Scaling from 50 MW (8 wells) to 200 MW (~25–30 wells) dilutes fixed EPC, interconnection and development costs across larger generation capacity.

(2) Drilling speed & success rate (~\$10/MWh): Higher well success rates (74% to 83%), rising bottom-hole temperatures (toward ~320°C) and ROP gains (520 to 1,200 ft/day) reduce wellfield capital intensity per productive well.

(3) Cost of capital (~\$11/MWh): WACC declines from ~9% (construction-phase, equity-heavy) to ~6% (mature, levered project finance) as subsurface risk is retired and projects become bankable.

(4) The EGS cost model is based on bottom-up well-by-well economics: drilling cost built from depth, RoP, non-productive time, rig rates, stimulation cost and dry hole probability. Well performance assumptions anchored to latest Fervo Energy disclosures where available; triangulated with peer-reviewed literature where Fervo data is not yet public. U.S. federal ITC and constant annual production decline assumed across all scenarios. Outputs shown as project-level LCOE (\$/MWh).

7a. Plant size

A geothermal “plant” is a multi-well pad: multiple production and injection well pairs drilled from a shared surface location into a common subsurface reservoir at 2–7 km depth. Each well pair consists of an injection well and a production well linked through engineered fracture networks. Cold water is pumped down the injection well, circulates through the hot fractured rock, and returns via the production well. Multiple well pairs are spaced sufficiently apart, typically several hundred metres between laterals, to avoid thermal interference between fracture

networks, while remaining close enough to share a single power plant and grid connection.

Plant scale has a material impact on unit economics. A 50 MW EGS plant currently requires approximately 8 production wells. A 200 MW plant requires 25–30 wells drilled from the same pad. Holding subsurface performance, drilling productivity and financing assumptions constant, CAPEX per MW falls from ~\$2,930/kW at 50 MW to ~\$2,400/kW at 200 MW, an 18% reduction, while OPEX per MW falls from ~\$140/kW to ~\$110/kW.

Exhibit 41

Scaling from 50 MW to 200 MW reduces modelled LCOE by ~\$14/MWh, driven by EPC and wellfield efficiencies

Cost Category	50 MW	200 MW
Total CAPEX (\$M)	150	485
Development & Engineering (\$M)	5	5
Interconnection (\$M)	25	85
Procurement & EPC (\$M)	110	380
Other (\$M)	10	15
CAPEX per MW (\$/kW)	2,930	2400
Annual OPEX (\$M/yr)	7	21
OPEX (\$/kW)	140	110

Source: TNI analysis

Notes:

(1) This table includes only costs that scale with, or are directly impacted by, plant size.

Procurement and EPC drives the largest saving, falling from \$2,225/kW to \$1,890/kW as larger plants allow more efficient turbine and balance-of-plant sizing, lower construction overhead per unit of capacity, and stronger supplier leverage. Development and site costs are largely fixed — permitting, engineering and project management do not scale proportionally with output — and dilute significantly at 200 MW. Interconnection follows the same pattern, with fixed substation and connection costs spread across four times the capacity. OPEX falls from \$140/kW to \$110/kW, a 21% reduction, as staffing, monitoring and maintenance do not increase linearly with plant size.

Translating these unit cost reductions into levelised terms, the shift from a 50 MW to a 200 MW plant contributes approximately \$14/MWh of the projected \$35/MWh reduction in EGS LCOE from ~\$90/MWh today to ~\$55/MWh by 2035. It is the single largest component of the cost reduction pathway, and one that does not depend on any improvement in drilling technology or subsurface performance.

7b. Drilling speed & success rates

Drilling has historically accounted for approximately 30–57% of total installed capital cost for a geothermal plant (Akindipe & Witter, 2025), so improvements in drilling efficiency and well success rates have a direct and material impact on LCOE.

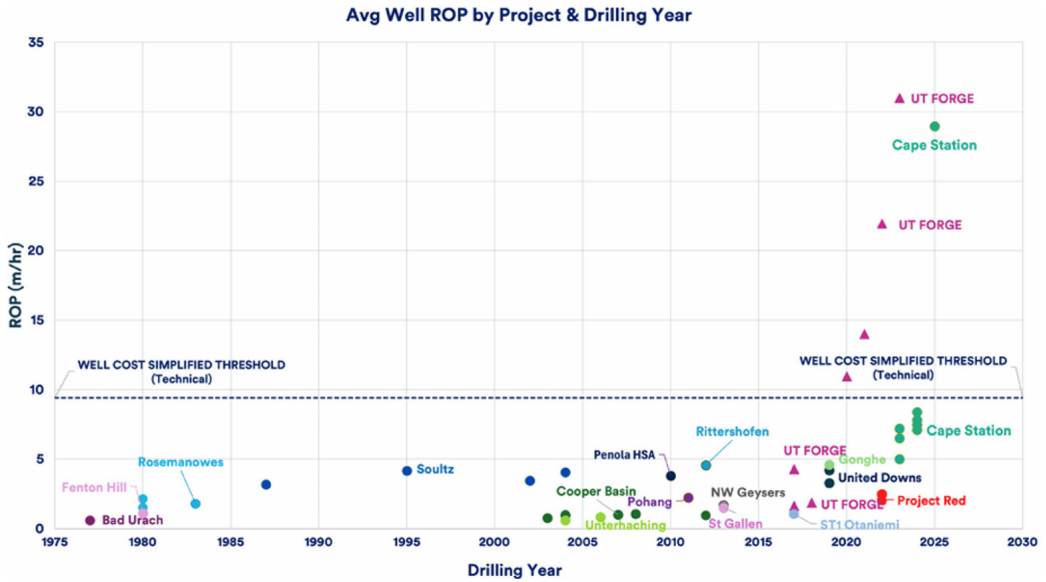
Since 2022, multiple commercial and demonstration projects have recorded material drilling performance gains in hard crystalline rock. At Cape Station (Utah), drilling time fell from 68 days on Fervo's first horizontal EGS well (Project Red, Nevada, 2022) to 21 days on the fastest Cape Station well (2024) — a 70% reduction — while well costs fell from \$9.4M to \$4.8M across the first four horizontal wells, a 49% reduction. The implied learning rate of 35% per doubling exceeds both the 13% shale industry rate at a comparable stage and the 18–30% range proposed for mature EGS programmes (Latimer & Meier, 2017). This is corroborated by the DOE's Frontier Observatory for Research in Geothermal Energy (FORGE) project in Milford, Utah where successive wells drilled to comparable depths have required materially fewer rig-hours with each campaign (DOE Pathways to

Commercial Liftoff, 2024). The chart below illustrates this progress across the global EGS fleet. Prior to 2020 virtually all projects cluster at 2–5 metres/hour drilling rates, while Cape

Station and FORGE, drilled in 2023–2024, both record rates of penetration of 28–31 metres per hour.

Exhibit 42

Average geothermal rate of penetration (ROP) over time; EGS drilling efficiency Has Quadrupled Since 2010 (with peaks at 10x)



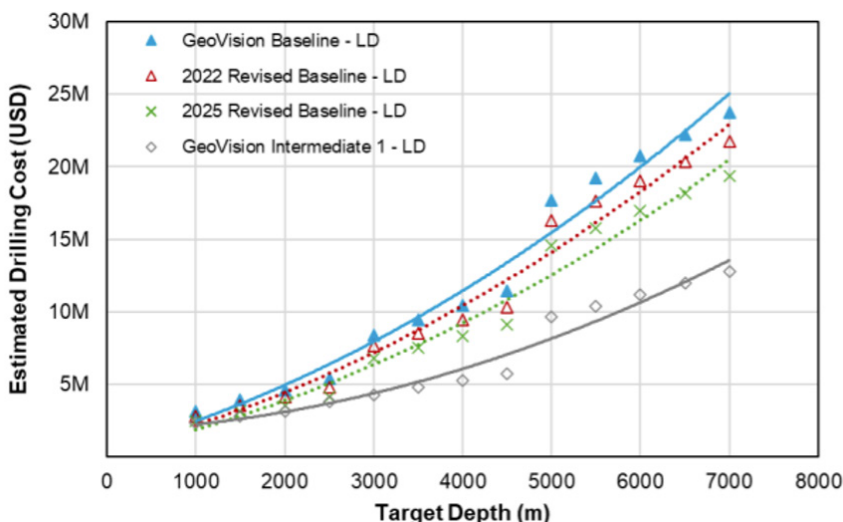
Source: CATF (2025)

The exhibit below shows National Renewable Energy Laboratory (NREL)’s large diameter (LD) geothermal drilling cost curves, updated in 2025 (Akindipe & Witter). These curves represent NREL’s estimates of the cost to drill geothermal wells to a given depth, and how they have revised them since their original GeoVision paper in 2019. Incorporating recent performance data from Fervo Energy, the 2025 costs are 25% lower than the 2019 costs

at the 4km depth (blue line vs green line), reflecting realised improvements in drilling performance. The lower grey line (“GeoVision Intermediate”) is NREL’s base case forecast for 2030 drilling costs which fall from \$9M to \$5M in 2025 dollars at the 4km depth. This demonstrates the progress Fervo has already made in moving down the learning curve and reducing drilling costs.

Exhibit 43

NREL geothermal drilling cost curves; 2025 revision shows material drilling cost reductions have already been achieved by Fervo



Source: Akindipe & Witter (2025)

Notes:

- (1) Compares GeoVision baseline (2019) with 2022 and 2025 revisions.
- (2) Derived from actual reported well cost data aggregated by NREL across the US geothermal industry.
- (3) LD: Large-diameter (9.625–12.25-inch) vertical open-hole drilling cost curves.

Rate of penetration (ROP)

Current EGS drilling performance is approximately 520 ft/day, based on recent field data from Cape Station (El-Sadi et al., 2024). We model this increasing to 1,200 ft/day by 2035, which corresponds to the lower bound of current shale oil and gas drilling speeds. The U.S. Department of Energy estimates active drilling rates of 120–200 ft/hour. Applying a typical 40% rig utilisation rate (i.e. the share of total time spent actively drilling) implies a total elapsed time equivalent of 1,200–1,900 ft/day (measured as well depth divided by total days on site, including casing runs, bit trips, and other non-productive time). We conservatively anchor to the lower end of this range to reflect the additional complexity of drilling high-temperature crystalline rock for EGS relative to sedimentary shale formations.

The U.S. Department of Energy Lutoff Report (2024) estimates that EGS drilling costs fall

by 10–25% for every doubling of cumulative wells drilled. Even a 10% learning rate implies that, with modest growth in cumulative well count, EGS drilling performance can realistically converge towards this 1,200 ft/day lower-bound shale benchmark by 2035. This 1,200 ft/day assumption feeds directly into our \$10/MWh conclusion below which also incorporates the increased well temperature and well drilling success rates.

Well drilling success rate

Well drilling success rates are higher in EGS than in conventional hydrothermal, but the economic impact of this difference is modest. Conventional hydrothermal wells have succeeded 54% of the time in the past on a new development platform, rising to ~90% when drilling wells at an existing site with established successful wells (IFC, 2013). Failed wells add approximately \$2–3/MWh to LCOE for a typical 25 MW hydrothermal project.

EGS removes the need to discover a naturally occurring reservoir, eliminating the largest source of exploration risk. Once a site is established, stimulation and subsurface learnings transfer directly to subsequent wells on the same site, supporting success rates of 85–90% on established platforms, similar to conventional geothermal sites. In addition, larger project scale means those costs are diluted across a greater number of productive wells. As a result, the contribution of well failure to EGS LCOE is below \$1/MWh and will decline further.

Well temperature economic impact

We model an increase in average well temperature from approximately 290°C to 320°C, reflecting the progression toward deeper and hotter resources as subsurface understanding improves. Higher temperatures increase energy yield per well, reducing the number of wells required per unit of generation and compounding the cost reductions driven by improved drilling performance.

Both anchor points are drawn from actual operating data. The 290°C baseline matches Fervo Energy’s Project Blanford appraisal well in Utah (February 2026), the hottest commercial EGS well drilled to date, and sits within the 250–300°C range used in NREL ATB, USGS and DOE Enhanced Geothermal Shot scenarios for next-generation EGS. The 320°C endpoint is referenced against Mazama Energy’s Newberry Volcano pilot, which recorded a peak bottom-hole temperature of 331°C in 2025, with prior site characterisation showing 320°C at only 3,000 m depth. Reaching a 320°C fleet average by 2035 requires the median commercial well, drilled outside Newberry-class settings, to deliver sustained production temperatures close to today’s pilot peaks.

Combined LCOE impact

The combined effect of higher well success rates (74% to 83%), improved ROP (520 to 1,200 ft/day) and higher average bottom-hole temperatures (290°C to 320°C)

reduces wellfield capital intensity materially, contributing approximately \$10/MWh of LCOE reduction by 2035.

Real-world performance is running ahead of these modelled assumptions. A 30-day flow test at Cape Station in 2024 achieved a record 107 kg/s flow rate at temperatures above 220°C, implying more than 10 MW of gross generation capacity per well — a level that NREL had not projected reaching until 2035. Notably, this output was achieved at a reservoir temperature below our 290°C modelled baseline, suggesting that the productivity gains compounded with the temperature uplift modelled above could deliver materially more than \$10/MWh of LCOE reduction over time. In February 2026 Fervo announced a further breakthrough at its Project Blanford appraisal well in Millard County, Utah, recording a reservoir temperature of 290°C at 3.4km. Crucially, Blanford’s reservoir comprises sandstones and carbonates rather than the harder igneous rocks typical of EGS sites — making it materially easier and cheaper to drill and fracture and signalling that the EGS-addressable resource base may extend well beyond the hard-rock plays that have anchored the industry’s forecasts to date.

There are risks to these productivity gains including water loss costs, well re-stimulation and heat dissipation. We discuss all of these in the chapter on technology. Thunder Said Energy’s (TSE) May 2026 reservoir model argues that part of Fervo’s Cape Station’s record 107 kg/s flow rates and >10 MW-per-well output reflects an under-spaced EGS architecture, in which roughly 80% of the heat extracted is being mined from the rock rather than drawn from sustainable subsurface upwelling. If that is right, sustained 30-year flow rates will require some combination of three responses, and the cost implications of the three differ materially. Wider inter-well spacing on future developments is the most benign — it is largely cost-neutral at the well level but requires materially more acreage per MW than Fervo’s current pad layout assumes, which is feasible on BLM land in the Western United States but constraining elsewhere.

Longer laterals are a material capex addition: TSE's modelling implies a 10km-lateral doublet runs roughly \$18M at \$400/ft, against ~\$4.8M for a current Cape Station well. A faster make-up drilling cadence is the most damaging to LCOE, because our model treats wells as essentially one-time capex. Re-drilling every 5–10 years rather than every 25–30 years could add \$10–20/MWh that is not in the \$55/MWh point estimate today. We will continue to test the hypothesis against actual Cape Station decline curves as longer-dated production data becomes available.

7c. Cost of capital

Cost of capital is a key driver of geothermal LCOE due to the capital-intensive, front-loaded nature of projects. As shown in Exhibit 44, the effective cost of capital declines across a project's lifecycle — from as high as 16% during exploration (100% equity financed) to ~9% at the construction phase (65% debt, 35% equity) and ~6% for mature operating assets (75% debt, 25% equity). Our LCOE of ~\$90/MWh is calculated using the construction-phase WACC of ~9%. Recalculating at the mature WACC of ~6% reduces LCOE by ~\$11/MWh by 2035.

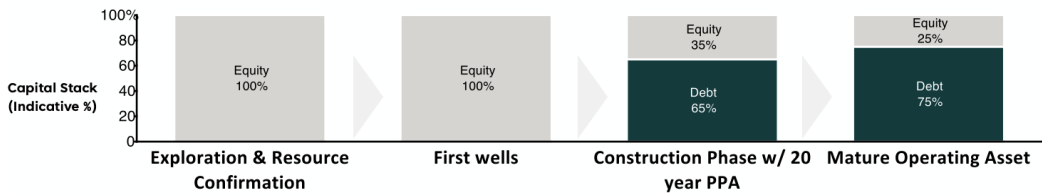
This reflects the transition from equity-funded development to leveraged project finance as risk declines. Early-stage exploration is financed with close to 100% equity due to subsurface uncertainty and lack of contracted revenues. Following successful drilling, resource validation and execution of long-term offtake agreements, projects become bankable, enabling the introduction of non-recourse debt.

Exhibit 44 illustrates this de-risking trajectory using the conventional hydrothermal capital frontier, which is the only segment of geothermal with a long enough financing track record to observe the full progression from exploration equity to infrastructure debt. The pattern is directly applicable to EGS. The driver of declining cost of capital is not the reservoir type but the shift from unproven subsurface risk to contracted, operating cash flows. Once an EGS project has validated its reservoir, signed a long-term PPA, and entered stable generation, lenders and equity investors price the asset on the same project finance basis as a conventional hydrothermal plant. Fervo Energy's \$421M non-recourse construction financing for Cape Station in March 2026, structured with senior secured debt alongside tax equity, demonstrates that this convergence is already underway.

Exhibit 44

As NGG de-risks, falling cost of capital will be a significant contributor to lower LCOEs

Traditional Geothermal Capital Frontier



	Exploration & Resource Confirmation	First wells	Construction Phase w/ 20 year PPA	Mature Operating Asset
Cost of equity	16%	15%	14%	12%
Cost of debt	-	-	8%	5%
WACC	16%	15%	9%	6%

Illustrative investors:

Equity	Breakthrough Energy Ventures; Clean Energy Ventures; Congruent Ventures; DCVC; DOE (Grants); Gigascale Capital; Khosla Ventures; Lowercarbon Capital	All Aboard Fund; Copenhagen Infra Partners; BlackRock; Baseload Capital; Just Climate; Spring Lane Capital;	Brookfield Infrastructure; CDPQ; Copenhagen Infrastructure Partners; Macquarie Asset Management; OTPP; Stonepeak Infrastructure
Debt	-	-	Allianz; Aviva Investors; EIB; IFC; KfW; MUFG; RBC; Société Générale; US DFC

Source: NREL (2025); Hatton et al. (2025); Beckers & Young (2017); Thunder Said Energy (2026)

Note: (1) Assumes 21% corporate tax rate

As assets enter stable operation, refinancing into infrastructure-style capital structures further reduces WACC through higher leverage and lower required returns. The combined effect is both a lower cost of capital and a greater proportion of lower-cost debt.

Further detail on financing structures and capital formation is provided in Chapter 11.

EGS Cost Reduction Forecast Summary

EGS is on a credible path to cost competitiveness. Our forecast of ~\$55/MWh by 2035 represents a central case within a wider range of outcomes, which we expect to fall between \$50–70/MWh, reflecting variation in subsurface performance, resource quality and execution. In the U.S., this range remains broadly competitive with natural gas across most market conditions, even if the central case is not fully achieved. Platform size and cost of capital are already beginning to travel in the predicted downward direction. Developers such as Fervo Energy are progressing from early ~50 MW demonstration projects to larger, multi-well platforms, enabling scale-driven reductions in fixed EPC and development costs. At the same time, access to non-recourse project financing

is emerging as projects demonstrate initial performance and secure contracted revenues, supporting a gradual decline in cost of capital from construction-phase levels toward infrastructure benchmarks.

The remaining and most consequential variable is drilling speed and success rates. While early data points are encouraging, the extent to which operators can consistently deliver higher well productivity, faster drilling rates and predictable reservoir outcomes across multiple sites will determine whether EGS achieves the lower end of the cost range. This is ultimately a learning curve problem: the faster the industry can move from site-specific success to repeatable, standardised development, the faster both capital intensity and perceived risk decline. In practice, the trajectory from ~\$90/MWh to ~\$55/MWh is less dependent on any single breakthrough than on the cumulative effect of incremental improvements in drilling, reservoir engineering and execution. If these learning effects materialise as expected, EGS should converge with, and in favourable cases undercut, competing sources of firm power. If they do not, costs are likely to stabilise toward the upper end of the \$50–70/MWh range.

8. What challenges will constrain growth of Next-Generation Geothermal?

Geology still defines where Next-Generation Geothermal can work. Drilling capacity (rig availability) determines how fast it can scale. Interconnection governs when it can earn revenue. The headline geothermal energy resource is large, but the deployable opportunity is shaped by the intersection of these three constraints, all of which are location or geology dependent.

In practice, the \$90-to-\$55/MWh LCOE trajectory is most likely to be achieved first in the western United States by the early-to-mid 2030s, where gradients exceed 45°C/km, oilfield drilling rigs can be redeployed, and some transmission capacity already exists to reach load centres. Europe and other international markets are likely to lag by 5–10 years due to the absence of a domestic drilling rig fleet and longer permitting cycles. Our central-case projection of 80 GW by 2035 reflects this reality — 80 GW is a large number in absolute terms but a tiny fraction of the theoretical base, underscoring how much of the opportunity remains blocked by drilling cost and electricity grid build-out.

Of that 80 GW global target, approximately 40 GW is in the United States — the primary near-term market. Achieving 40 GW of US geothermal capacity by 2035 requires drilling an average of ~360 wells per year at 10 MWe per well, roughly a 4x increase in US geothermal drilling activity within a decade. For context, this is well within the scale of precedent set by US shale gas, which expanded from fewer than 1,000 horizontal wells per year in 2005 to over 10,000 by 2012 as the economics proved out.

Earlier in this paper, we projected that global Next-Generation Geothermal power capacity could reach 80 GW by 2035 and 220 GW by 2050, implying cumulative capital investment of approximately \$350B and \$1.1T respectively. Our LCOE modelling indicates a pathway from ~\$90/MWh to ~\$55/MWh by 2035 for EGS projects, where favourable geology, existing drilling infrastructure and grid access converge.

However, achieving this cost trajectory and deployment scale is contingent on overcoming three structural constraints — geology, drilling capacity, and grid interconnection. Geography

underpins each of these. Heat is not uniformly distributed; high-spec drilling infrastructure is not always where the best NGG drilling sites are; and the best geothermal basins are often distant from high electricity demand load centres and transmission capacity. As a result, while the theoretical resource base is vast, the economically and logistically deployable opportunity set is materially narrower.

Geology

Geology is the primary, non-negotiable constraint. Geothermal potential is often cited in global terawatt terms, but commercial viability depends on thermal gradient (rate of temperature change with depth), depth, and rock properties. High-temperature gradients are concentrated in specific tectonic settings, while much of the world's continental crust exhibits lower gradients that require deeper and more expensive drilling.

Globally, high-quality resources cluster along tectonic plate boundaries and volcanic systems, including the Pacific Ring of Fire, the East African Rift, Iceland, and parts of Central America and western North America. Stable

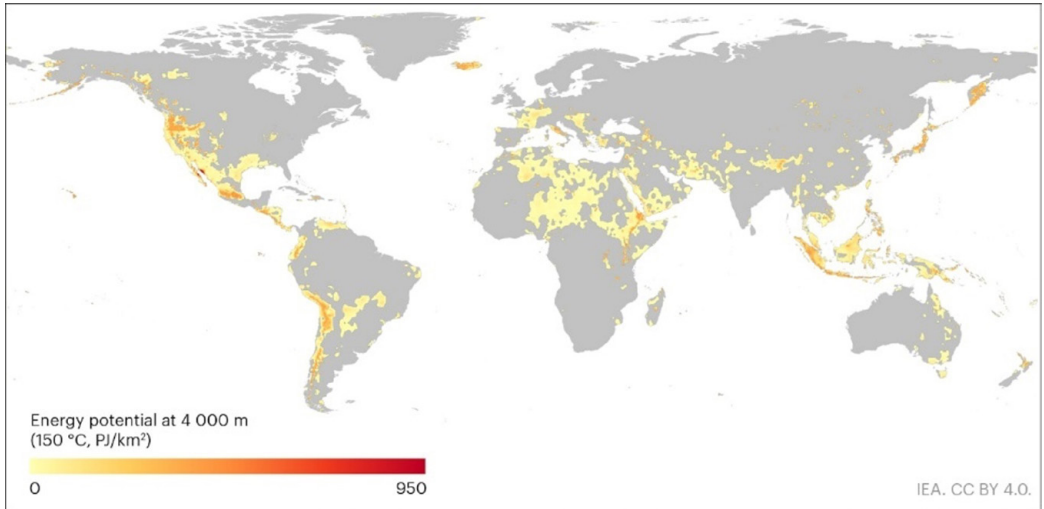
continental interiors across much of Europe, Africa, and Asia typically exhibit lower heat flow and therefore lower gradients. While heat exists everywhere at sufficient depth, economically accessible heat does not.

Exhibit 45 shows the global distribution of geothermal energy potential at 4,000 metres depth for temperatures above 150°C, measured in petajoules per square kilometre

(PJ/km²). The yellow-to-red shading indicates increasing energy density. Crucially, this map reflects conventional hydrothermal potential — areas where naturally occurring high temperatures are accessible at moderate depth. The concentration along tectonic boundaries is clear: the western Americas, East Africa, Iceland, Indonesia, and the Philippines dominate. Most continental interiors show negligible potential at this threshold.

Exhibit 45

High-gradient geothermal resources cluster in countries with existing installed capacity



Source: IEA (2024)

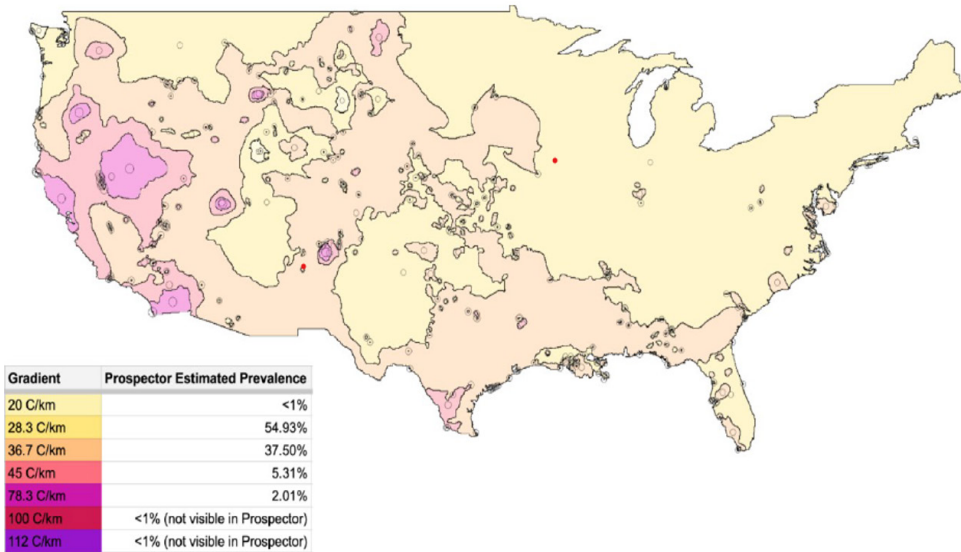
For EGS, the relevant question is not where natural hydrothermal reservoirs exist, but where thermal gradients are high enough to reach commercially viable temperatures (~200°C+) without prohibitive drilling costs. Based on NREL Geothermal Prospector data as shown in Exhibit 46 below, approximately 5% of the contiguous U.S. land area (~400,000 km²) exhibits gradients of ≥45°C/km — sufficient to reach 200°C at roughly 4.4 km depth, within the range of current EGS drilling capability. A further ~2% (~160,000 km²) has gradients of ≥78°C/km, representing the highest-quality EGS resource. These areas are concentrated in the western states: the Great Basin (Nevada, Utah), Snake River Plain (Idaho), the Cascades (Oregon), and parts of California. For context, 400,000

km² is roughly the size of California. Much of the eastern U.S. exhibits gradients closer to 20–30°C/km, implying wells exceeding 5.5 km to reach 200°C. Because drilling costs rise non-linearly with depth, these gradient differences translate directly into divergent project economics. EGS therefore expands the viable footprint well beyond conventional geothermal, but the economically attractive resource remains geographically concentrated.

In practical terms, our \$55/MWh LCOE target by 2035 is achievable in regions with gradients above ~45°C/km; in lower-gradient regions (30–40°C/km), LCOEs are likely to remain above \$70–80/MWh through to the 2030s absent a step-change in drilling technology.

Exhibit 46

Elevated geothermal gradients in the U.S. are concentrated in western basins



Source: NREL (2018)

Achieving TNI's U.S. forecast of 40 GW by 2035 requires adding ~36 GW of new capacity over ten years. At 10 MWe per well (our 2035 target productivity), this 36 GW implies roughly 3,600 new production wells, or ~360 production wells per year. At current well productivity of 6.5 MWe, the requirement would be 550 production wells per year. In contrast, the U.S. drilled ~35 production wells in 2024, and there are only ~3,700 geothermal production wells operating globally today. Reaching 360 wells per year therefore requires a roughly 4x increase in U.S. geothermal drilling activity within a decade — ambitious, but not without precedent. U.S. shale gas drilling scaled from fewer than 1,000 horizontal wells per year in 2005 to over 10,000 by 2012 as the economics proved out.

Drilling rigs

EGS companies like Fervo Energy are using standard oil & gas drilling rigs, often repurposed directly from oil & gas jobs, but slightly modified for higher temperatures and different fluids. The labour force is also largely from the oil and gas industry. However, in geologically attractive geothermal basins,

deployment is constrained by access to suitable drilling capacity. Deep, large-diameter EGS wells require a narrow subset of high-specification land rigs capable of handling long 4 to 7 kilometre laterals, large hole sizes, high hook loads, and sustained high-temperature circulation.

Out of roughly 540 active U.S. land rigs, nearly all are currently deployed in oil and gas basins. EIA estimates that there are approximately 400-500 rigs “stacked” or not being utilised. But, geothermal competes for the same top-tier units used in ultra-long shale gas programmes. This creates direct competition with gas operators. With the recent expansion of North American gas drilling, the same high-spec rigs required for EGS will be absorbed into shale programmes, where operators can justify premium day rates and multi-well contracts supported by immediate commodity revenue. Early-stage geothermal developers are less able to lock in long-term contracts at scale and are therefore exposed to oil and gas cycle dynamics. In practice, geothermal is a price-taker for the most capable segment of the land rig fleet.

Despite President Trump’s push for more drilling and given the increases in prices caused by the war in Iran, one might expect a surge in oil and gas drilling. However, for the next 5 years, EIA’s current official outlook is relatively flat. In its longer-range 2025 outlook, EIA says crude output rises from the current 13 mb/d to about 14.0 mb/d in 2027 and 2028 and then begins to decline after 2030 in most cases. For gas, EIA says dry gas production rises from 38.4 Tcf in 2024 to roughly 42.6–44.3 Tcf in the early 2030s, with production then staying relatively flat in most cases. This forecast reflects an assumption that producers are not counting on high oil and gas prices to remain high long enough to deploy new rigs in the field.

Geography reinforces the constraint. Most high-spec rigs are concentrated in Texas and Louisiana, while near-term EGS development is centred in the western United States. Mobilising a rig to a remote geothermal basin can cost on the order of \$2M and only becomes economic under sustained multi-well drilling campaigns. Contractors are reluctant to move rigs for single projects, while developers require predictable geothermal resources to justify rig mobilisation.

To quantify the rig requirement: at approximately 25 days per EGS well (including mobilisation, drilling, completion and stimulation) and ~300 operating days per rig per year, each dedicated rig can drill ~12 wells annually. Delivering 360 wells per year therefore requires roughly 30 dedicated geothermal rigs — approximately 3% of the U.S. land rig fleet including idle rigs. This is a material reallocation but not an impossible one, particularly if oil and gas activity moderates or purpose-built geothermal rigs enter service. At current productivity (~6.5 MWe/well, implying ~550 wells per year), the requirement rises to ~40-50 rigs.

In the United States, rig access is possible and only represents a cyclical and coordination problem because a large oilfield fleet exists that can, in principle, be reallocated. In countries without a meaningful oil and gas industry, the constraint is more structural. There may be no domestic fleet of suitable rigs, limited high-temperature service capability, and no established directional drilling workforce. In such markets, rigs and services must be imported, materially increasing lead times and cost. Until drilling programmes scale to dozens of rigs operating continuously and supply chains deepen, drilling capacity will remain a material throttle on EGS deployment.

Exhibit 47

A typical oil land rig usable by EGS geothermal drilling



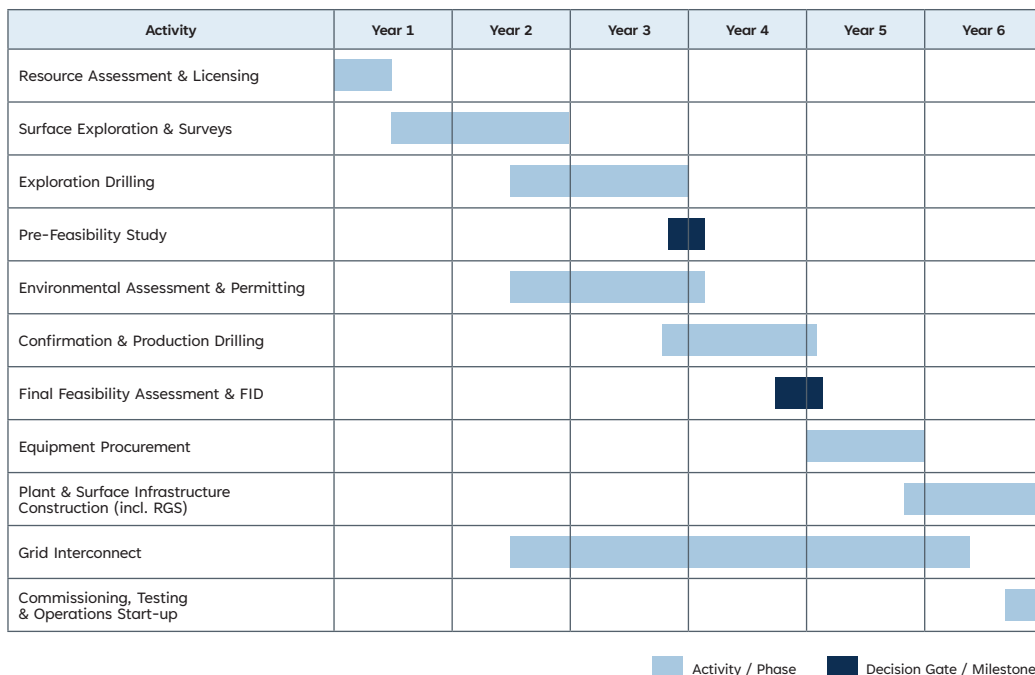
Grid Interconnection

Finally, even where geology and drilling align, grid interconnection has become the dominant pacing constraint on timing to revenue. A project may complete drilling and surface construction yet face multi-year delays before delivering electricity to the grid.

In the United States, average interconnection timelines have expanded from roughly three years in the mid-2010s to five to seven years today. In many cases, as you can see in Exhibit 48, queue time exceeds the combined duration of drilling and plant construction. This reflects a structural imbalance between the volume of proposed generation and the capacity of grid operators to process studies and allocate upgrades, with backlogs driven primarily by solar, wind, and storage.

Exhibit 48

Grid interconnection efforts need to start nearly at the beginning of any geothermal energy project to see grid connections by the end of year 6



Source: DOE GeoVision (2019); DOE Pathways to Commercial Liftoff (2024); IEA (2024)

For geothermal developers, the constraint is structural rather than technology-specific. Smaller 10 to 50 MW projects can struggle to absorb fixed network reinforcement (e.g., transmission line) costs, particularly where upgrades are allocated on a stand-alone basis. Geography again matters: high-gradient geothermal basins are often distant from major load centres, increasing the likelihood that transmission upgrades are necessary. Although regulatory reforms aim to shorten

queue times, implementation remains uneven and transmission build-out continues to lag generation ambition. Of the three obstacles described here, interconnect is expected to be the largest gating factor on EGS scaling in the US. Grid enhancement technologies such as solid-state transformers, dynamic line ratings and superconducting power lines may help free up transmission capacity, but policy changes that reduce regulatory interference would have the most beneficial impact.

9. What first-mover advantage in NGG can be gained from siting technology that leads to securing the best geothermal land leases?

Siting/subsurface characterisation skills and early lease control are emerging as primary sources of durable competitive advantage in Next-Generation Geothermal power. The Bureau of Land Management (BLM) administers geothermal leasing across 245 million acres of public land in the western United States, the vast majority of which remains unleased. As NGG commercial viability is validated, this acreage is already being repriced: average BLM lease prices rose 282% in 2025 to \$127/acre, and for the first time every parcel offered was sold. Developers who combine superior subsurface characterisation with disciplined acreage acquisition today can secure a cost and productivity advantage that is difficult for later entrants to replicate. The window to execute that strategy at low cost is narrowing rapidly.

Geothermal rights in the United States exist as a legally distinct category of subsurface interest, separate from oil and gas rights, hard mineral rights, and surface rights. The legal framework varies materially by jurisdiction. California defines geothermal resources as the natural heat of the earth and all associated energy, explicitly excluding hydrocarbons. Utah defines a geothermal resource by temperature threshold, requiring a separate lease for water or steam above 120°C. Texas enacted legislation declaring geothermal heat a property of the surface estate, meaning that where surface and mineral rights have been severed, the surface owner holds the geothermal right. This fragmentation of state law creates material title complexity for developers operating across multiple jurisdictions and means that thorough title search is a prerequisite before any acreage acquisition programme.

On federal lands, the framework is more standardised. Geothermal projects are leased under the Geothermal Steam Act of 1970, which functions similarly to the Mineral Leasing Act: lands amenable to geothermal projects are leased to the highest qualified bidder. The BLM issues competitive geothermal leases for an initial ten-year primary term, allowing the lessee to explore

and develop the geothermal resource, with extension available if the lessee establishes production or demonstrates diligent exploration. A critical structural point is that an oil and gas lease on federal land does not convey geothermal rights. The two are governed by separate statutory frameworks and require separate leases. This means that O&G operators holding large positions in geologically prospective western basins do not automatically hold the geothermal rights to the same acreage, a structural opportunity that NGG developers can exploit directly.

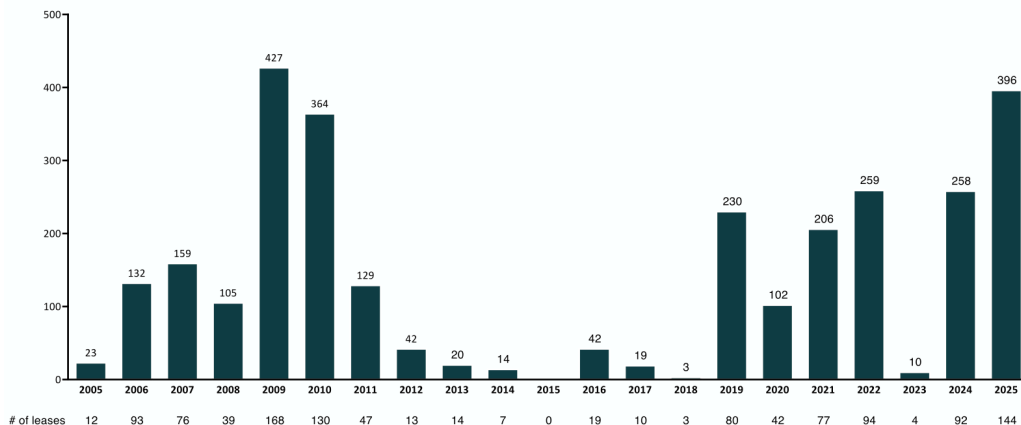
The total acreage currently under active geothermal lease is a small fraction of the prospective total. As Exhibit 49 shows, BLM geothermal lease activity collapsed between 2015 and 2018, reaching zero new acres in 2015, before recovering strongly from 2019 onward and reaching approximately 396,000 acres in 2025 alone. The post-2019 recovery reflects the same forces driving NGG investment more broadly: EGS technology validation, data centre demand for firm power, and supportive federal policy. In December 2025, the BLM published new guidance directing annual competitive geothermal lease sales across all states with pending lease nominations, further accelerating the pace of acreage availability.

Exhibit 49

US BLM geothermal lease activity has grown significantly since 2019, with 396,000 acres leased in 2025. A spike in 2009–10 driven by government (ARRA) incentives was followed by a decade of near-zero activity before the current NGG-driven wave.

U.S. BLM geothermal leases by effective date

Thousands of acres leased



Source: McKinsey; US Department of Interior BLM

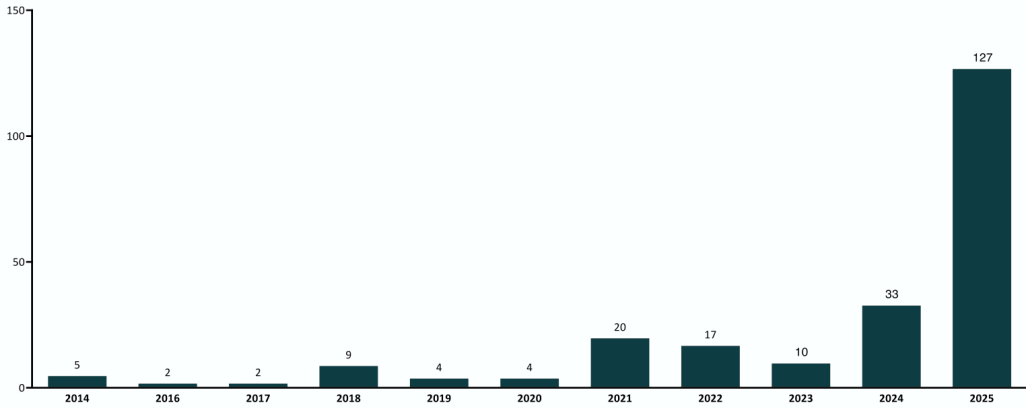
Conventional hydrothermal sites, the operating assets of Ormat, Calpine, and other incumbents, are largely locked up within established fields such as the Great Basin, Salton Sea, and The Geysers. However, these represent a geographically constrained subset of the total prospective resource. The more significant competitive dynamic concerns EGS-prospective acreage in basins with high thermal gradients but no visible signs of geologic activity at the surface -- so-called blind systems -- where incumbents have historically had no reason to hold leases because the resource was uneconomic to develop under pre-NGG technology assumptions. This is precisely the acreage that next-generation developers are now racing to secure.

The lease pricing data makes clear that the repricing of this acreage is already underway. As Exhibit 50 shows, average BLM geothermal lease prices were negligible for most of the period between 2014 and 2020, rarely exceeding \$10/acre on average, with bid spreads between lowest and highest offers remaining tight. The inflection came in 2021, when the Nevada auction saw a highest bid of approximately \$100/acre, the first time any auction had crossed three figures, coinciding with the initial wave of NGG venture capital and early EGS demonstration results. From there the trajectory has been consistent and steep, with average prices reaching \$33/acre in 2024 and \$127/acre in 2025, a 282% year-on-year increase, according to BloombergNEF and BLM data.

Exhibit 50

Average price per acre paid at BLM geothermal auctions, 2014–2025 rose from \$33/acre in 2024 to \$127/acre in 2025, the highest on record

Average price paid per acre at BLM auctions
USD



Source: BloombergNEF; US Bureau of Land Management

Note: Data for 2025 is January–September.

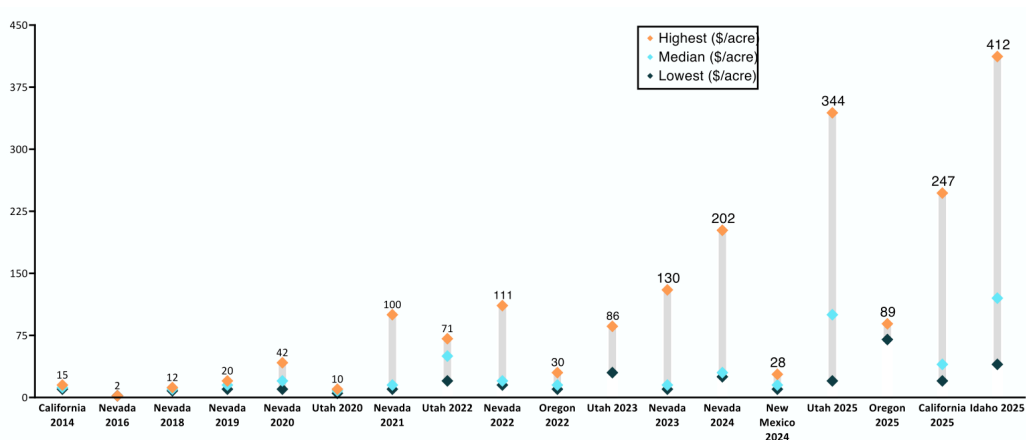
The per-auction bid spread data, shown in Exhibit 51, demonstrates that the gap between lowest and highest bids widened dramatically across all states. Idaho’s inaugural geothermal lease sale reached a high of \$412/acre against a low of approximately \$40/acre. Utah reached \$344/acre against a low near zero. California saw a high of \$247/acre, placed by Chinati Minerals, a subsidiary of Fervo Energy, marking the formal entry of NGG developers as active competitors in the land market alongside incumbents. Ormat, for

its part, paid \$202/acre in Nevada in 2024, its highest recorded bid, suggesting that even the incumbent most familiar with the quality of available parcels is repricing its own willingness to pay significantly. This bid dispersion reflects a market beginning to differentiate between high-quality and speculative acreage rather than treating all parcels as commodities, precisely the dynamic that preceded acreage inflation in the shale gas industry.

Exhibit 51

Per-acre winning bids (lowest, median, highest) at federal BLM geothermal auctions by state and year, 2014–2025. Bid spreads have widened dramatically in 2025, with Idaho reaching \$412/acre and Utah \$344/acre

Per acre winning bids at BLM auctions
USD



Source: BloombergNEF; US Bureau of Land Management

Note: Excludes Nevada 2017 due to lack of data. Only includes auctions where two or more parcels were sold. Auctions with only two parcels exclude the median.

The emergence of AI-native geothermal exploration platforms is materially changing the economics and speed of resource identification and directly informs which acreage is worth bidding on. Zanskar Geothermal uses artificial intelligence tools trained on vast geophysical and geological datasets — including gravitational and magnetic fields, rock types, fault lines, and drilling data — to estimate the location of geothermal resources before drilling, significantly reducing the risk and cost of exploration. In December 2025 it announced the discovery of the first confirmed blind geothermal system in over thirty years at its Big Blind site in Nevada, identified entirely through AI-based prospecting. Its Pumpernickel discovery in September 2025 further validated the approach, encountering reservoir temperatures of approximately 137°C at 760 metres depth at a site with no prior confirmed resource. Zanskar claims to have already reduced discovery costs per megawatt by an order of magnitude compared to inflation-adjusted costs incurred during geothermal’s last major greenfield exploration period.

The key question is whether AI-based siting creates a durable competitive moat or a transient first-mover advantage. In practice, it is primarily the latter. The underlying inputs, including gravity and magnetic surveys, USGS temperature gradient maps, and legacy well data, are largely public. As a result, differentiation does not come from data ownership but from interpretation, model quality, and execution speed.

More importantly, the informational advantage decays quickly. Once a discovery is disclosed through permitting or drilling results, adjacent acreage is immediately de-risked, attracting competing bids and compressing returns. This dynamic mirrors other subsurface industries: early insights are valuable, but they rapidly diffuse. The durable advantage therefore lies not in the algorithm itself, but in converting insight into control. Developers that translate superior siting into secured leases, and then into proven well performance, lock in an advantage that cannot be competed away. The algorithm is a screening tool; the acreage is a scarce, defensible asset.

The US shale gas revolution demonstrated that the greatest value was often created before drilling began—through early, informed land acquisition. A small group of companies used superior geologic insight and a willingness to act under uncertainty to lease large acreage positions cheaply, long before shale was widely considered economic. Firms like Chesapeake Energy, Range Resources, and EOG Resources moved quickly to secure core acreage that later proved highly productive, generating outsized returns. By contrast, Mitchell Energy—which pioneered the technical breakthrough in the Barnett Shale—was less aggressive in scaling land acquisition, and much of the downstream value was ultimately captured by faster-moving competitors. The lesson is that subsurface understanding combined with speed in leasing created a durable competitive advantage, often more important than the drilling technology itself.

For geothermal developers—especially EGS developers—the parallel is direct. The most attractive opportunities may lie in “blind” systems with no surface expression, where strong geothermal potential exists but has historically been overlooked by traditional geothermal players. As EGS siting and characterisation technology improves, these areas could become the geothermal

equivalent of early shale basins. Developers who can identify favourable subsurface conditions ahead of the market—and secure rights early—may gain access to the highest-quality resources at low cost. In this sense, geothermal’s future leaders are likely to be those who treat it as a land and geology game first, and a drilling execution problem second, echoing the playbook that defined the shale era.

Today, a well-capitalised developer can still assemble a multi-basin lease position for \$20M. This is modest relative to the \$200M required to develop a single 50 MW project, effectively creating a low-cost option on future resource development. However, this asymmetry is unlikely to persist. As siting improves and drilling success rates increase, lease prices will re-rate toward the underlying value of the resource.

This creates an attractive investment guideline: look for the first wave of developers who acquire high-quality acreage at low cost and prove it technically. These companies are effectively building portfolios of de-risked sites ahead of infrastructure capital. This approach is already being pursued by Ignis Energy, with a focus on early land capture and validation rather than immediate build-out.

10. Where in the geothermal value chain will the most value be captured?

As venture capital investors, we have always struggled to see Next-Generation Geothermal as a proto-typical venture backed business. Why haven't oil & gas incumbents like Shell and Chevron or traditional integrated geothermal companies like Ormat and Calpine taken the lead in developing this new industry? If the costs, capabilities, competitors and customers are the same or similar between O&G/traditional geothermal and NGG, then they are in the same business (so my strategy consultant training had taught me). For reasons described below, the timing has not been right, yet, for the incumbents to enter, although most have toes in the water through relationships with early entrants. Oil field services companies like Halliburton and SLB are not in this business today, other than through some supply arrangements to Fervo, but could be the "Picks & Shovels" to NGG just as they are for oil & gas. The shale gas parallels to NGG are instructive to the extent that, only once the technology was proven, the shale gas business became less fragmented and achieved a relevant scale, did the oil majors dive in, usually acquiring the largest independent early entrants. We expect a similar evolution to take place with Next-Generation Geothermal. Just as with the shale revolution, the greatest value will be captured in pre-emptive land lease acquisition, exploration, drilling and power production in an integrated model.

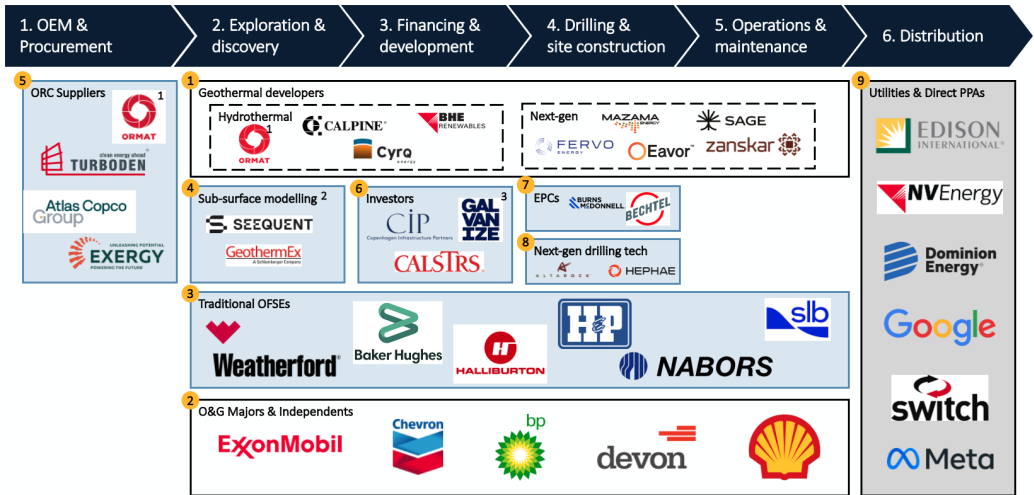
10a. What is the traditional geothermal value chain and how will the Next-Generation Geothermal value chain differ?

The high-level value chain for traditional and Next-Generation Geothermal does not differ significantly. Discovery and drilling are where it differs most, and McKinsey usefully breaks out the major hydrothermal developers Calpine, Ormat and Cyrq from the next

generation developers, Fervo, Eavor, Sage and Zanskar, in Exhibit 52 below. This exhibit illustrates the Next-Generation Geothermal value chain, aligning the major participants underneath each stage of their own involvement. All of these companies could conceivably become meaningful participants in the long term NGG industry, many shown below with only small roles at present in traditional or NGG.

Exhibit 52

Next-Generation Geothermal value chain



Source: McKinsey

Ormat is unique as a full stack geothermal play operating as both a project developer and supplier of materials such as ORC power plants. Many traditional OFSEs also provide geothermal sub-surface modelling services, but these focus on optimising existing O&G sites. The investors shown here are an example set who may fund project build-out once technology is derisked and proven, but before platforms are sufficiently mature to attract traditional infrastructure capital.

Stages in the value chain:

(1) OEM and Procurement (6–18 months typical elapsed time in stage of development)

Developers secure long-lead equipment including turbines, heat exchangers, drilling rigs, casing, pumps and control systems. For Next-Generation Geothermal, specialised drilling components and high-temperature materials may be required due to the increased heat, greater depth and increased length of laterals. Procurement timelines depend on manufacturing capacity and supply chain constraints, particularly for ORC turbines.

(2) Exploration & Discovery (6–24 months)

Geological surveys, seismic imaging, temperature gradient wells and subsurface modelling are conducted to confirm resource quality. This stage reduces resource risk and determines expected temperature, pressure and flow characteristics.

(3) Financing & Development (6–18 months, often overlapping)

Developers secure equity, project finance and, where applicable, grants or tax incentives. Power purchase agreements or merchant offtake strategies are negotiated. This stage converts a technically viable resource into a financeable infrastructure project.

(4) Drilling and Site Construction (12–36 months)

Wells are drilled, cased and completed. For EGS and GGS, this may include horizontal drilling and hydraulic stimulation. Multi-well pads are typically developed sequentially. Surface plant construction, including turbine installation and grid interconnection,

proceeds in parallel. Drilling is the largest component of capital expenditure and the primary driver of cost reduction over time.

(5) Operations and Maintenance (25+ year asset life)

Once operational, the plant requires continuous monitoring of temperature, flow rate and reservoir pressure. Reservoir management is critical to maintain output and prevent thermal decline. Ongoing maintenance of turbines and surface equipment ensures high-capacity factors.

(6) Distribution (3–12 months for grid integration; ongoing thereafter)

Power is delivered either via grid interconnection under a long-term PPA or into wholesale markets. Risk at this stage is driven primarily by interconnection timelines, transmission capacity and local market structure, and is typically lower than upstream resource and construction risk. Some projects may operate behind-the-meter or off-grid, particularly where large data centres seek dedicated, firm power without transmission constraints.

Key groups of participants in the Next-Generation Geothermal value chain:

(1) Hydrothermal (Traditional) Geothermal Developers:

Hydrothermal developers, such as Ormat Technologies and Calpine, build and operate projects in naturally permeable reservoirs where commercial heat and flow are already proven. Their skillset lies in site control, reservoir management experience, permitting track record and existing transmission access. Geological uncertainty is lower, capital costs are more predictable, and value is captured through disciplined execution and long-term asset ownership.

(2) Next-generation developers, including Fervo Energy, Eavor, Zanskar, Mazama Energy and Sage Geosystems,

pursue Enhanced Geothermal Systems and related techniques that create permeability where it does not naturally exist. These firms assume higher subsurface and technical risk but aim to unlock a much larger resource base. Value is created by demonstrating repeatable well performance, reducing drilling costs and converting engineered reservoirs into financeable power assets. The central distinction is therefore not simply technology, but risk profile: hydrothermal developers optimise known resources, while next-generation developers attempt to expand the addressable market itself.

(3) O&G Majors & Independents:

Examples include ExxonMobil, Chevron, BP and Devon Energy. These firms participate as investors, technical partners or potential acquirers once early feasibility is demonstrated. Their core contribution is subsurface expertise, drilling capability and balance sheet capacity developed in hydrocarbons. While unlikely to assume first-of-a-kind risk, they can accelerate deployment at scale if technology risk declines. Their importance to the sector lies in their operational scale, access to cheap capital and project management expertise. At present, however, most remain largely inactive in Next-Generation Geothermal, reflecting a continued strategic focus on core oil and gas activities due to supportive sectoral and policy tailwinds for hydrocarbons, and the perception that geothermal offers limited upside under fixed-price PPA structures.

(4) Traditional Oilfield Services

Companies (OFSEs): Examples include Weatherford, Baker Hughes and Halliburton. These companies provide rigs, directional drilling, logging, stimulation and well completion services during drilling and construction. Revenues are earned on a per-well service basis rather than through long-term power ownership. If geothermal

drilling volumes scale materially, these firms may capture meaningful value as “Picks & Shovels” providers. The durability of that value depends on whether geothermal-specific tools become proprietary and differentiated or remain commoditised adaptations of oil and gas equipment.

(5) Subsurface Modelling Specialists:

Firms such as Seequent and Geothermics reduce geological risk before significant capital is committed. They analyse seismic data, model fracture networks and simulate temperature, pressure and flow behaviour to estimate well productivity and long-term thermal performance. Although oilfield services companies also offer subsurface software, geothermal specialists focus specifically on heat extraction and reservoir longevity rather than oil or gas recovery.

(6) ORC Power Plant Suppliers:

Examples include Ormat Technologies, Turboden and Atlas Copco. The Organic Rankine Cycle turbine is the core surface component in most geothermal plants, converting heat into electricity. The ORC package is one of the largest single surface capital items, is technically specialised and can be capacity constrained. It also directly influences thermal-to-electric efficiency and therefore project economics. This paper focuses on ORC suppliers rather than the full universe of OEMs because most balance-of-plant components form a small fraction of overall CAPEX and are relatively commoditised.

(7) Later-Stage Growth and Project Investors:

These investors provide construction equity and platform capital once subsurface risk is partially reduced but before projects qualify as fully de-risked infrastructure. Their participation occurs during financing and development and often continues into operations. Returns reflect exposure to construction and ramp-up risk offset by

contracted or semi-contracted revenues. This group bridges the capital gap between venture investors and core infrastructure funds.

(8) Engineering, Procurement and Construction Contractors (“EPCs”):

Engineering, procurement and construction contractors, such as Bechtel and Burns McDonnell, design and build the surface plant, manage procurement integration and oversee grid interconnection. Their economic exposure is concentrated in the construction phase under fixed-price or cost-plus contracts. While they do not typically retain long-term ownership, execution quality at this stage directly affects capital cost, schedule risk and early operating performance.

(9) Next-Generation Drilling Technology Providers:

Examples include GA Drilling, Hephæ Energy Technology and Quaise Energy. These companies aim to reduce drilling cost per metre, increase accessible depth or enhance reservoir permeability. Because drilling represents the largest share of geothermal capital expenditure, improvements in drilling speed, durability or flow enhancement have a direct impact on levelised cost of energy. If one approach becomes dominant, intellectual property may capture durable value, particularly if service providers adopt the technology as industry standard.

(10) Utilities and Direct Power Purchase Agreement Offtakers:

Examples include Edison International, Dominion Energy, Google and Meta. These entities provide long-term revenue certainty through power purchase agreements or regulated procurement. Their involvement typically begins during financing and development and continues through distribution. Contracted offtake transforms a technically viable asset into a financeable infrastructure

project. Corporate buyers, particularly hyperscale data centre operators, are increasingly seeking firm, carbon-free power that avoids transmission bottlenecks, strengthening the strategic relevance of behind-the-meter geothermal supply.

10b. What are the lessons from the US Shale Revolution for NGG value creation?

It is not obvious that Next-Generation Geothermal developers will capture the majority of long-term value. As projects scale, capital intensity rises and cost of capital becomes decisive in determining LCOE. A useful historical analogue is the U.S. shale gas industry. Shale required new subsurface techniques, significant experimentation and large-scale capital deployment once proven. Importantly, value capture shifted over time, from early innovators, to landholders, to capital partners, and ultimately to service providers and consolidators.

The shale gas parallels to NGG are highly relevant to the likely NGG evolution to the extent that, only once the technology was proven, the business became less fragmented and achieved a relevant scale, did the oil majors dive in, usually acquiring the largest independent early entrants. We expect a similar evolution to take place with Next-Generation Geothermal. Just as with the shale revolution, the greatest value will be captured in pre-emptive land lease acquisition, exploration, drilling and power production in an integrated model. Successful early entrants may be acquired or become major independent producers just as EOG Resources and Chesapeake Energy did in shale gas.

To assess who is most likely to capture value in Next-Generation Geothermal, it is helpful to examine the US shale gas industry through the five stages of development that have occurred between 1980 and the present:

- **Stage 1** – Technology Development (c. 1980–1997):

After early hydraulic fracturing experiments dating back to the late 1940s, a small independent energy exploration company, Mitchell Energy, spent nearly two decades refining commercially viable shale fracking, culminating in a breakthrough in 1997.

- **Stage 2** – Early Commercialisation (c. 1997–2003):
Second movers secured acreage, drilled initial wells to prove productivity, and formed joint ventures with larger capital providers.
- **Stage 3** – Rapid Expansion (c. 2003–2009):
Capital markets funded aggressive drilling programmes; service providers accumulated technical advantage as drilling standardised.
- **Stage 4** – Consolidation (c. 2009-2014):
Supermajors entered at scale via acquisition once assets were de-risked and had positive cash-flow.
- **Stage 5** – Financial Rationalisation (c. 2014–present):
After a decade of debt-funded expansion, falling commodity prices triggered widespread restructurings that eliminated excess leverage and forced a shift from growth-at-any-cost to disciplined capital allocation, repricing the sector's cost of capital and restoring sustainable equity returns.

While presented sequentially for analytical clarity, these stages overlap in practice. Different basins, companies and capital providers operated at different development stages simultaneously.

Shale Revolution Stage 1 – Technology Development (1980-97)

The first stage of the U.S. shale gas industry was defined by prolonged experimentation and high technical risk. From the early 1980s to 1997, Mitchell Energy invested approximately \$250M attempting to

unlock commercial shale gas production in the Barnett Shale. Supermajors did not meaningfully participate during this period, as the opportunity was small relative to their core oil portfolios and the technical uncertainty was substantial. Value resided in accumulated subsurface knowledge and operational learning rather than scale. Mitchell Energy proved the model but did not become the long-term dominant player; instead, it reduced uncertainty for the wider ecosystem.

Next-Generation Geothermal sits in an analogous position today. Companies such as Fervo Energy and Eavor are engaged in multi-year efforts to demonstrate repeatable reservoir performance at commercial temperatures. Capital remains largely venture, strategic or grant-backed. Incumbent O&G majors and independents, despite having capabilities that could make them a natural fit for Next-Generation Geothermal, have confined themselves to minority strategic investments rather than committing

fully to the technology. For instance, Chevron and BP invested in Eavor’s \$51M Series A in February 2021, with BP following on in Eavor’s \$239M Series B in October 2023, and Devon Energy invested in Fervo Energy’s \$500M Series D.

Similarly, hydrothermal developers are organisationally geared toward maximising value from their existing asset bases and typically lack the risk appetite to pursue next-generation technologies at scale. While existing hydrothermal sites may ultimately prove attractive EGS candidates, operators are understandably reluctant to risk disrupting current power production to trial unproven systems. Instead, they are making selective strategic investments with a view to entering once the technology is validated. One exception is Ormat, which co-led Sage Geosystems’ \$97M Series B in January 2026, reflecting its position as a fully integrated operator with a significant landbank and greater strategic flexibility than pure O&G players

Exhibit 53

Involvement of conventional hydrothermal developers in Next-Generation Geothermal

Operator	Geothermal Investments	Geothermal Partnerships
Ormat Technologies	Sage Geosystems – Series B (\$97M, Jan 26)	SLB – EGS-focused agreement to co-develop and commercialise integrated geothermal assets
Calpine Corporation	None	GreenFire Energy – GreenLoop EGS demo hosted at The Geysers (via subsidiary)
Coso Operating Company	None	XGS Energy – 3,000-hour closed-loop test at Coso field
Cyraq Energy	None	Eavor – 20 MW Next-Generation Geothermal pilot projects in Northern California

Source: PitchBook

Shale Revolution Stage 2 – Early Commercialisation (c. 1997–2003):

Once Mitchell Energy proved commercial viability in 1997, the primary uncertainty shifted from technology to strategic positioning. The key insight for second

movers was that long-term value would not accrue to those who merely understood fracking, but to those who controlled large, high-quality acreage positions in productive shale basins. Companies such as Devon Energy and Anadarko Petroleum moved aggressively to accumulate land, often before

the market fully repriced the resource. Their strategy was disciplined: secure extensive leasehold, drill a limited number of wells to demonstrate productivity, and then introduce a well-capitalised partner to accelerate development while retaining operatorship and the majority of long-term upside.

Anadarko's 2010 Marcellus partnership with Mitsui & Co. illustrates this model clearly. Mitsui acquired a 32.5% interest in Anadarko's Marcellus position for \$1.4B and funded a substantial development carry, while Anadarko retained operatorship and control over a large net acreage position. Devon's 2001 acquisition of Mitchell Energy for \$3.1B marked the first major institutional endorsement of shale, signalling that the technology had moved from experimental to scalable resource play. The supermajors still largely remained on the sidelines during this phase. This stage was defined by two forms of leverage: control of scarce resource positions and intelligent capital structuring to reduce cost of capital.

For Next-Generation Geothermal, this phase will begin once reservoir repeatability and commercial LCOE are demonstrated across multiple wells and multiple geographies. At that point, premium thermal resource positions with demonstrated flow performance are likely to become the primary strategic asset. Developers that have secured attractive sites and demonstrated their technology are likely to replicate the shale model: prove productivity at limited scale and then introduce strategic or financial partners through structured JVs to accelerate deployment while retaining operatorship and meaningful upside. Investors can therefore capture significant upside by backing developers able not only to prove and de-risk their technology, but also to secure and validate a landbank capable of rapid scale-up using third-party capital at a declining cost of capital.

Shale Revolution Stage 3 – Rapid Expansion (c. 2003–2009):

Once acreage positions were established and early partnerships funded development, shale transitioned from strategic positioning to industrial scaling. Capital markets financed aggressive drilling programmes across multiple basins, and shale became a repeatable infrastructure financing activity. The locus of competitive advantage shifted: as horizontal drilling and multi-stage fracturing standardised, firms such as Schlumberger and Halliburton accumulated operational data, refined completion techniques and embedded intellectual property across thousands of wells. The technical learning curve increasingly resided within the service layer rather than solely with the acreage holders.

For Next-Generation Geothermal, this stage would correspond to multi-site build-out once drilling performance is predictable and projects are replicable across basins. As capital intensity rises, weighted average cost of capital becomes a dominant driver of competitiveness, potentially favouring larger balance sheets and infrastructure investors. Drilling standardisation could simultaneously elevate the importance of the "Picks & Shovels" layer: if specific high-temperature drilling systems or stimulation techniques become widely adopted, the firms controlling those systems may accumulate ecosystem-wide data and technical leverage.

This positioning is already visible. Several oilfield services companies have taken strategic stakes in leading geothermal developers, aligning themselves as preferred drilling partners while investing directly in next-generation drilling technologies that could become foundational to the sector. Helmerich & Payne has invested across multiple rounds in both Fervo Energy and Eavor, while Nabors has focused more squarely on the enabling technology layer through investments in Hephæ Energy Technology, Quaise Energy and GA Drilling. SLB has formalised an EGS-focused co-development agreement with Ormat.

Exhibit 54

OFSEs are positioning themselves for geothermal growth

OFSE	Geothermal Investments
Nabors Industries	GA Drilling – Later Stage VC (\$83M, Mar 26); Later Stage VC (\$15M, Apr 24); Series C (\$8M, Mar 22) Sage Geosystems – Series B (\$97M, Jan 26); Series A (\$45M, Sep 24) Ignis Energy – Series A (\$14M, Feb 25) Hephae Energy Technology – Seed (\$6M, Nov 24) Quaise Energy – Series A (\$52M, Jun 22) GeoX Energy – Corporate (\$11M, Jun 21)
SLB	Ormat ¹ (Oct 25)
Helmerich & Payne (H&P)	Eavor – Series A (\$51M, Feb 21) Eden GeoPower – Seed (\$13M, Oct 23) Fervo Energy – Series B (\$28M, Apr 21); Series C (\$138M, Aug 22); Later Stage VC (\$244M, Feb 24); Series D (\$499M, Dec 24) Geothermal Technologies – Seed (\$1M, Mar 20)
Precision Drilling	Eavor – Series A (\$51M, Feb 21)

Source: PitchBook

Note: EGS-focused agreement to co-develop and commercialise integrated geothermal assets, not an equity investment

In this phase, value capture broadens and begins to shift across the ecosystem. Developers benefit from scaling assets and building portfolios of operating projects. Capital providers gain access to infrastructure-style, contracted returns as risk declines. Service companies benefit from higher volumes and from embedding proprietary tools and data into repeat deployments. For project developers, the central competitive question is no longer who invented the technology, but who can operationalise it into a scalable infrastructure platform and secure the lowest-cost source of capital.

Shale Revolution Stage 4 – Consolidation (c. 2009-2014):

The fourth stage of the U.S. shale revolution was characterised by consolidation and capital repricing rather than technological breakthrough. By this point, shale reservoirs were de-risked, producing at scale and supported by reserve data. The asset class no longer resembled a speculative technology

play; it increasingly behaved like scalable, long-duration energy infrastructure. As a result, competitive advantage shifted from innovation to balance sheet strength and cost of capital.

From 2009 onward, large integrated oil and gas companies entered through acquisition. ExxonMobil's \$41B purchase of XTO Energy in 2010 marked the clearest signal that shale had moved from fringe to core strategy. Chevron's acquisition of Atlas Energy in 2010 and BHP Billiton's purchase of Petrohawk in 2011 reinforced the pattern. These transactions were not experiments in new drilling methods; they were acquisitions of proven resource platforms with visible development inventories.

By this stage, innovation had become incremental. Horizontal drilling and multi-stage fracturing were established techniques. The primary sources of differentiation shifted to acreage quality, operational efficiency and, critically, access to low-cost capital. Supermajors could finance development more

cheaply and deploy drilling programmes at scale, accelerating consolidation and compressing returns for smaller players. For Next-Generation Geothermal, the analogous phase would occur once EGS projects are repeatable, cash-flowing and financeable on infrastructure terms. At that point, a scaled developer with established assets could represent an attractive acquisition target for oil and gas majors. The asset base would resemble a reserves-backed, infrastructure-style platform: long-duration, subsurface-driven and aligned with core O&G capabilities. The strategic question would shift from “can this work?” to “who can own and scale it most efficiently?”

In this stage, value capture shifts decisively toward entities with balance sheet strength and low cost of capital. Early innovators may monetise through sale or dilution, while service providers continue to benefit from ongoing drilling and maintenance activity. As in shale, the ultimate long-term winners are unlikely to be determined solely by who first proved the technology, but by who controls mature asset portfolios and can finance expansion most efficiently.

Shale Revolution Stage 5 – Financial Rationalisation & Capital Discipline (c. 2014–present):

The final phase of shale’s evolution was financial rather than technological. Following the 2014 oil price collapse and subsequent downturns, the sector underwent widespread restructuring. More than 200 North American shale companies filed for bankruptcy between 2015 and 2021, eliminating excess leverage and exposing the fragility of a growth model reliant on continuous reinvestment and cheap external capital.

Investor expectations shifted from production growth to free cash flow and capital returns. Drilling intensity moderated, reinvestment rates declined and compensation structures increasingly emphasised return on capital. Cost of capital repriced upward, and discipline was externally imposed.

Only after this rationalisation did shale become structurally investable for long-duration equity capital. With leverage reduced and growth tempered, surviving operators generated sustained free cash flow and returned capital to shareholders. Value capture shifted toward low-breakeven acreage holders with strong balance sheets and access to competitively priced financing.

For Next-Generation Geothermal, this stage provides a clear caution. Rapid technological validation and supportive policy could attract significant capital inflows. However, if deployment accelerates ahead of stable unit economics and disciplined capital structuring, returns may compress, replicating shale’s mid-cycle expansion. Long-term winners are therefore unlikely to be those who grow fastest, but those who align development pace with sustainable economics and prudent leverage.

In conclusion, the shale experience underscores a central lesson: technological success and rapid scaling do not guarantee durable equity value capture. Periods of low cost of capital can incentivise over-expansion, compress returns and shift value toward consumers and service providers rather than upstream investors. Sustainable value emerged only after capital discipline was imposed.

For Next-Generation Geothermal, the determinant of long-term value capture will not be invention alone, but the interaction between resource quality, deployment discipline and cost of capital. Those who combine technical competence with balance sheet strength and rigorous capital allocation are most likely to capture enduring value.

10c. Will O&G Majors Enter at Scale, and When?

The oil and gas majors have the capabilities, the capital, and increasingly the strategic rationale to become dominant players in Next-Generation Geothermal. They have not moved aggressively yet because the economics remain pre-threshold, the sector

is too small relative to their minimum deal size, and their organisational incentive structures continue to reward hydrocarbon returns. TNI's view is that the entry trigger is three to five years away, contingent on Cape Station's operating performance through 2026–2028, and that when it occurs it will be rapid, acquisition-led, and concentrated in the two to three developers that have secured the best acreage and demonstrated the most repeatable subsurface performance.

In this section and the paper we use “oil and gas majors” referring primarily to the integrated international supermajors — ExxonMobil, Chevron, Shell, BP, TotalEnergies, Equinor, Eni and Repsol. In certain places, we use the term more loosely to also include the larger US NNGs (Devon, EOG, Diamondback and similar) and, where relevant, the diversified mining majors that have taken venture positions in geothermal (BHP, Anglo American). Where the distinction between these groups matters for the argument we make it explicit. Oilfield services firms (SLB, Halliburton, Baker Hughes) are a separate category and are discussed in their own right in Section 10b (shale parallels) and Section 12c (picks and shovels), where they are the natural acquirers of the picks-and-shovels layer rather than of developers. We focus principally on US-listed names because they have expressed the clearest interest in Next-Generation Geothermal to date and operate in the market most likely to set the global cost curve.

Approximately 80% of the capital investment in a geothermal project involves skills, equipment and workflows common to the O&G industry (IEA, 2024). The capability overlap goes beyond drilling. EGS operations — circulating fluids between paired injector and producer wells through a fractured subsurface reservoir to extract thermal energy — are structurally analogous to the water-flooding Enhanced Oil Recovery (EOR) and Steam-Assisted Gravity Drainage (SAGD) techniques that the integrated majors have refined across conventional oil basins and the Alberta oil sands for decades. Reservoir-modelling expertise and fluid-flow

management, not just drilling fleets and balance sheets, may be among the decisive factors drawing the majors into geothermal over time. The oil majors are arguably better placed to add value in the subsurface management of operating EGS assets than to run the power-plant surface layer, which reinforces the acquisition-rather-than-build entry pattern discussed below.

Despite this, three structural constraints have suppressed major engagement to date. First, O&G is currently far more profitable than geothermal. This profitability gap is not narrowing, especially in the wake of the Iran war. Recent improvements in US shale productivity and Permian extensions have, if anything, widened it through 2026. Until major upstream IRRs decline materially or geothermal IRRs rise to within striking distance, the capital-allocation choice inside a supermajor remains binary. Second, the sector is too small for meaningful capital deployment. The minimum deal size for a supermajor to move its financial needle is measured in gigawatts, and no single developer yet offers a portfolio at that scale. Third, internal incentive structures remain misaligned. Geothermal is a long-cycle infrastructure investment with seven-year development lead times and 25-year asset lives that does not fit the quarterly reporting cadence governing capital allocation at publicly-listed large integrated oil companies.

The behaviour of individual majors reflects these constraints. **ExxonMobil** has been the most explicit in its de-prioritisation of geothermal. CEO Darren Woods stated in March 2024 that the company is not “actively pursuing” geothermal, acknowledging capability alignment but citing unresolved economics. Geothermal was excluded entirely from ExxonMobil's \$17B low-carbon investment fund for 2022–2027.

BP has taken a more active position, with participation in Eavor across two funding rounds totalling approximately \$280M.

Chevron has been the most publicly ambitious, pursuing pilots across Nevada,

Japan and Indonesia and securing selection for a DOE EGS demonstration in Sonoma County (US DOE, 2024), yet its largest 2025 energy commitment was a partnership with Engine No. 1 and GE Vernova to deliver 4 GW of gas-fired power for US data centres at an estimated cost of \$8B, showing its strategic focus on O&G. Chevron invested in Baseload Capital, a geothermal equity investment

platform based in Sweden, at the platform level (via Chevron Technology Ventures) in 2021 and later deepened the relationship through a joint venture to develop geothermal projects, combining Baseload's project pipeline and geothermal expertise with Chevron's capital, subsurface capabilities, and ability to scale.

Exhibit 55

Oil & gas majors have participated in NGG by buying options; not yet a strategic priority

Company	Equity Investment	Partnerships / Projects	Strategic Positioning
Shell	-	15-year PPA with Fervo Energy (31 MW, Cape Station, Apr 2025); exited Dutch geothermal heat (Feb 2025)	Positioned as offtaker rather than developer; exited direct project exposure
Chevron	Eavor (\$51M, 2021); Baseload Capital (\$25M, 2021, debt finance)	JV with Baseload (US); pilots in Nevada (Weepah Hills), California (GeoZone, DOE), Japan (MOECO)	Pilots to projects approach; actively testing but not scaling
BP	Eavor (\$40M Series A; \$239M Series B)	Eavor Geretsried project (Germany); Texas Geothermal Alliance	Most concentrated capital commitment; focused on single technology (closed-loop)
ExxonMobil	-	-	Not actively pursuing; monitoring only; excluded geothermal from \$17B low-carbon plan
TotalEnergies	-	-	No clear geothermal strategy or activity
BHP Ventures	Eavor (\$6M, 2022); Fervo (\$28M, 2021)	-	Minority venture exposure; non-strategic
Anglo American	GA Drilling (\$83M, 2026); Eden GeoPower (~\$13M Seed, Oct 2023)	-	Focus on enabling technologies rather than project ownership
Devon Energy	Fervo (\$500M Series D, 2024)	-	Largest direct investment by a US independent; early conviction

Source: PitchBook, Company Press Releases

Baseload Capital is a geothermal-focused investment and development platform that takes equity stakes in early-stage geothermal projects, helping finance, build, and scale portfolios of heat and power assets across multiple markets. Rather than acting as a

lender, it operates like a hybrid of a developer and private equity sponsor, taking on early subsurface and project risk and then bringing in partners to scale projects. Bill Gates' Breakthrough Energy Ventures has a stake in Baseload.

Shell has undergone the most visible pivot: having withdrawn from Dutch geothermal heat development in February 2025, it repositioned as the first named off-taker for Fervo's Cape Station under a 15-year PPA (Shell / Fervo, April 2025), offloading development risk while retaining commercial exposure to the asset class.

Among US independents, Devon Energy stands out as the only operator to have committed materially to the sector to date, participating in multiple Fervo Energy funding rounds including the \$500M Series D in late 2024. Devon CEO Clay Gaspar reinforced this stance at CERAWeek 2026, describing geothermal as a potential future option within Devon's technology portfolio — language consistent with active monitoring rather than imminent scale-up, but notable for being the most explicit public endorsement to date from a major US E&P.

Prior forays into wind and solar by the European majors have largely failed to generate competitive returns. BP wrote down approximately \$1.5B in offshore wind assets and cut its renewables budget by \$5B in 2024 after admitting green ambitions were misaligned with market realities, while Shell and TotalEnergies have also scaled back renewables spending materially. This history makes significant capital commitment to any pre-commercial clean energy technology a difficult internal sell, particularly one whose LCOE has not yet been validated at scale and whose project pipeline remains too small to move a major's financial needle. Geothermal must therefore demonstrate not just technical viability but investable financial returns before it commands meaningful balance sheet allocation from the majors — a bar that has not yet been cleared.

When entry by oil majors occurs, it is unlikely to start with building projects internally. The development cycle is long, subsurface risk remains material, and majors have limited experience in power market execution. More

fundamentally, they are not organisationally set up for this type of innovation. Long development timelines, uncertain early-stage returns, and bureaucratic capital allocation processes all work against geothermal's risk profile. Early participation will more likely take the form of JVs and farm-ins, alongside offtake agreements that provide exposure without taking on full development risk. Full acquisition comes later. Once one or two developers have assembled multi-GW portfolios of producing assets with demonstrated performance, they become natural targets, not for their technology, but for their resource base and operating platform.

A second feature of this entry pattern is that the natural acquirers will not be a single global supermajor consolidating the sector, but rather different majors and utilities acquiring assets in their respective home markets. Geothermal power, unlike LNG, cannot be physically traded across borders — every megawatt produced must be consumed within the same grid — which means the long-term ownership of NGG assets will fragment along regional lines. In the US, the natural acquirers are the integrated majors with US upstream platforms (Chevron, ExxonMobil) and the larger US E&Ps (Devon, EOG); in Europe, OMV, Equinor, BP and Shell alongside national utilities; in Indonesia and the Philippines, Pertamina and the regional IPPs. This is a meaningful contrast to the shale gas analogy, where ExxonMobil's XTO acquisition reshaped the global cost curve. NGG exits are likely to look more like local utility or regional-major M&A than continental consolidation, which has implications for both deal size (smaller, more numerous transactions) and exit multiples (set by local rather than global benchmarks).

The implication for investors is to back the developers that secure the best acreage, prove it technically, and can attract the most capital to eventually emerge as credible acquisition targets for oil majors.

11. How will Next-Generation Geothermal get financed?

funded exploration to low-cost, debt-financed infrastructure, enabled by progressive subsurface derisking and financial innovation. As projects demonstrate well performance and secure contracted revenues, they become bankable and can access non-recourse project finance and, ultimately, infrastructure capital and public equity investors. The pace at which this transition occurs will determine both the scalability of the sector and the extent of LCOE reduction. The recent Fervo Energy IPO signifies a major inflection point in favour of debt, growth equity and public financing to meet the huge capital requirements of NGG. Even with the Fervo IPO, we are tens of billions short of the average annual \$30–35B of capital needs of the sector to reach the 80 GW 2035 projection.

As quantified in Chapter 2 above, we estimate that NGG will require approximately \$35B, annually, in capital expenditure to exploit the available techno-economically viable market size around the world, or a cumulative capital investment of \$350B by 2035. We would expect this to ramp up from \$5B pa in the next few years, and then to rapidly accelerate once the technology is de-risked.

Next-Generation Geothermal projects should follow a predictable financing progression as subsurface uncertainty declines. Early-stage exploration and initial drilling are typically funded with close to 100% equity, reflecting binary geological outcomes and the absence of contracted revenues. As projects move into appraisal and early development, capital structures begin to involve creative financing and strategic partners. Once wells are successfully drilled, reservoir performance is demonstrated and long-term offtake

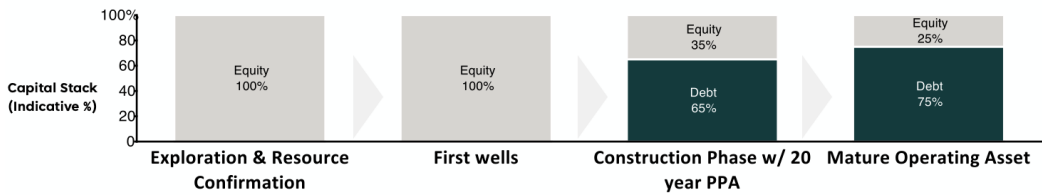
agreements are secured, projects become bankable and can access non-recourse project finance. As assets enter stable operation, refinancing into infrastructure-style capital structures further reduces the cost of capital through higher leverage and lower required returns. This progressive repricing of risk, and corresponding decline in WACC, is a central driver of LCOE reduction.

Cost of capital is a key driver of geothermal LCOE, and achieving sustained cost reductions requires a transition from high-cost equity to lower-cost debt. For Next-Generation Geothermal, this means bridging the gap between high-risk, equity-funded exploration and low-risk, debt-financed infrastructure. The speed at which this transition occurs will determine both the pace of deployment and the trajectory of LCOE reduction.

Exhibit 56

Cost of capital declines significantly as projects prove viability and technology derisks

Traditional Geothermal Capital Frontier



	Exploration & Resource Confirmation	First wells	Construction Phase w/ 20 year PPA	Mature Operating Asset
Cost of equity	16%	15%	14%	12%
Cost of debt	-	-	8%	5%
WACC	16%	15%	9%	6%

Illustrative investors:

Equity	Breakthrough Energy Ventures; Clean Energy Ventures; Congruent Ventures; DCVC; DOE (Grants); Gigascale Capital; Khosla Ventures; Lowercarbon Capital	All Aboard Fund; Copenhagen Infra Partners; BlackRock; Baseload Capital; Just Climate; Spring Lane Capital;	Brookfield Infrastructure; CDPQ; Copenhagen Infrastructure Partners; Macquarie Asset Management; OTPP; Stonepeak Infrastructure
Debt	-	-	Allianz; Aviva Investors; EIB; IFC; KfW; MUFG; RBC; Société Générale; US DFC

Source: NREL (2025); Hatton et al. (2025); Beckers & Young (2017)

Note: Assumes 21% corporate tax rate

Fervo Energy’s capital history is the most instructive case study currently available. Over eight years, its financing evolved from non-dilutive grants and seed equity through successive venture rounds, strategic corporate investment, construction bridge debt, before closing a \$421M non-recourse project financing for Cape Station Phase I in March 2026, a structure that would be entirely conventional in wind or solar.

Debt financing in the NGG sectors represents a major milestone. The \$421M non-recourse construction financing — the “Project Granite” facility — was earmarked for its 100 MW Cape Station Phase I project in March 2026. The financing structure included a \$309M loan covering from construction through to COD, a \$61M investment tax credit bridge loan and a \$51M letter of credit facility, all underpinned by fully contracted, investment-grade cash flows with long-term offtake agreements in place. The transaction was syndicated across a broad bank group, demonstrating that once key risks are resolved (well performance, contracting, permitting and engineering definition), Next-Generation Geothermal can access conventional infrastructure-style debt

markets. Similar patterns are evident across Eavor Technologies and Zanskar Geothermal, where access to project-level capital followed validation of well performance and operating data.

The same trajectory is now extending into public equity markets: on 13 May 2026, Fervo IPO’d at \$27/share and sold 70 million shares raising \$1.89B. The book was more than 10x oversubscribed. Shares are trading around \$33 today (14 May 2026), which pushed market cap above \$10B. They left some money on the table (\$700–800M in value that went to IPO allocates rather than the company), but the oversubscription and strong debut signal institutional depth for geothermal and firm, 24/7 carbon-free power as an asset class.

This is likely among the best exits in climate tech history. Four All Aboard Coalition members (Breakthrough Energy Ventures, Congruent Ventures, DCVC, and Capricorn) were early investors, along with co-investment network member Galvanize. Based on rough math and assumptions, a \$10M check at a Series B, accounting for dilution across subsequent rounds, is likely

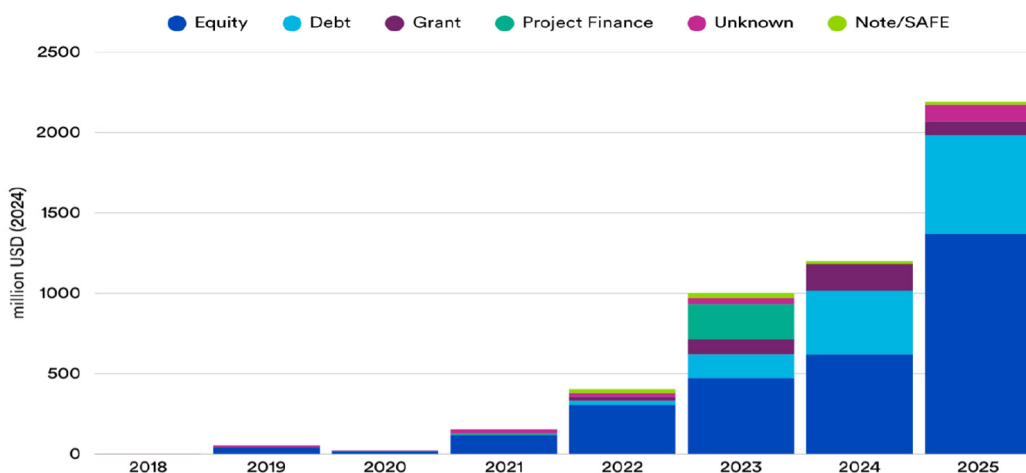
worth \$300M+ at today's price (gross MOIC of 30x+ on paper). Public markets have now assigned a \$10B+ valuation to a next-generation geothermal company, establishing a real comparable where none previously existed. This directly benefits Zanskar. Fervo's success validates the core geothermal thesis with institutional investors, project finance lenders, and off-takers who previously had no public market anchor.

The next six months are the real test. Cape Station Phase I (100 MW) is expected to deliver first power in late 2026, with Phase II (400 MW) targeted for 2028. The standard

180-day lock-up means early investors cannot sell until approximately November 2026, almost exactly when the market will reprice the stock based on whether Cape Station actually delivers. If drilling hits snags, reservoir performance disappoints, or first power slips into 2027, the stock could be materially lower by the time distributions happen. Conversely, if Cape Station delivers on time, it validates the full technology thesis and unlocks project finance. The next six months are very consequential for the company and for the geothermal sector broadly.

Exhibit 57

Only a very small amount of financing has gone into Next-Generation Geothermal compared to what will be required. Debt finance has already entered the picture.

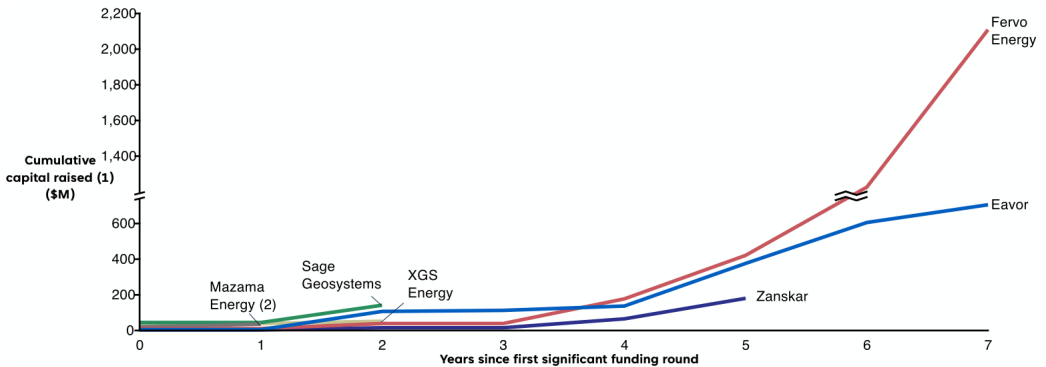


Source: IEA (2026)

Exhibit 58

Fervo (EGS) and Eavor (ACL) have attracted the bulk of the capital to date and lead the race for NGG financing (this ignores \$1.9B IPO proceeds for Fervo)

Cumulative capital raised since first significant funding round (>\$3m)



Source: PitchBook

Note: (1) Includes grants and project financing

(2) Mazama was established as a joint venture between AltaRock and Blade Energy Partners in 2023; AltaRock was a drilling technology company that first raised Series A financing in 2007

The central constraint on scaling is therefore subsurface bankability, which remains the primary bottleneck to accessing low-cost capital. In the recent MIT/CATF geothermal conference, Sarah Black of alfa8 laid out possible solutions for financing geothermal from where we are today. She suggested that addressing this will require financing structures that separate, diversify or progressively underwrite geological risk. Structured JV-style approaches can split ownership, risk and capital between subsurface development and surface infrastructure, allowing each component to be financed by the most appropriate capital pool. Portfolio-level financing vehicles can aggregate projects across geographies and resource types, creating diversification that supports tighter pricing and higher leverage. Co-designed bankability pathways, developed alongside lenders and infrastructure investors, can define the technical milestones required to unlock debt earlier in the development cycle. Debt certainty mechanisms, such as pre-committed facilities with milestone-based drawdowns, can further reduce financing risk by ensuring capital availability as projects derisk.

As these structures mature and standardise, the investor base is likely to broaden from venture and specialist developers toward infrastructure funds, private credit, insurers and pension capital. This deepening of the capital pool is critical, as greater competition and familiarity should compress financing costs over time. Ultimately, geothermal deployment and cost reduction are tightly linked: the faster subsurface risk can be translated into bankable, financeable assets, the faster cost of capital declines and LCOE falls. Ultimately, integrated geothermal companies like Ormat and some of the oil majors will be financing the growth of NGG with their access to very low cost capital including cheap project debt capital.

We forecast that the bulk of capital invested into geothermal energy will ultimately come from large oil and gas majors. The \$35B/year capex represents but 5% or less of global capex in oil and gas. In recent years, the global oil and gas industry has been investing on the order of ~\$550–700B per year in capital expenditures, depending on how broadly you define the sector and the year.

12. What is the optimal investment strategy for private investors into Next-Generation Geothermal?

We see three alternative strategies for investing in Next-Generation Geothermal:

- 1) **Invest in developers focused on EGS today with large land banks, with access to large amounts of low-cost capital and strong strategic relationships with integrated hydrothermal players like Ormat and/or oil & gas majors likely to provide long-term liquidity.**
- 2) **“Picks & Shovels” investments: the venture opportunity is concentrated in five sub-segments where incumbent tools are fundamentally inadequate for next-generation conditions: AI-driven subsurface characterisation and siting, novel rock destruction, high-temperature downhole electronics and measurement, and non-hydraulic stimulation and power plant innovations.**
- 3) **The “first 10%” strategy which invests in developers focused on the early stages of development from the pre-survey to test drilling stages and who exit to other developers who take the project to completion. These early de-risking stages account for approximately 10% of the total project capex but embed the highest risk stages of development. This strategy can be powerfully combined with a land bank strategy.**

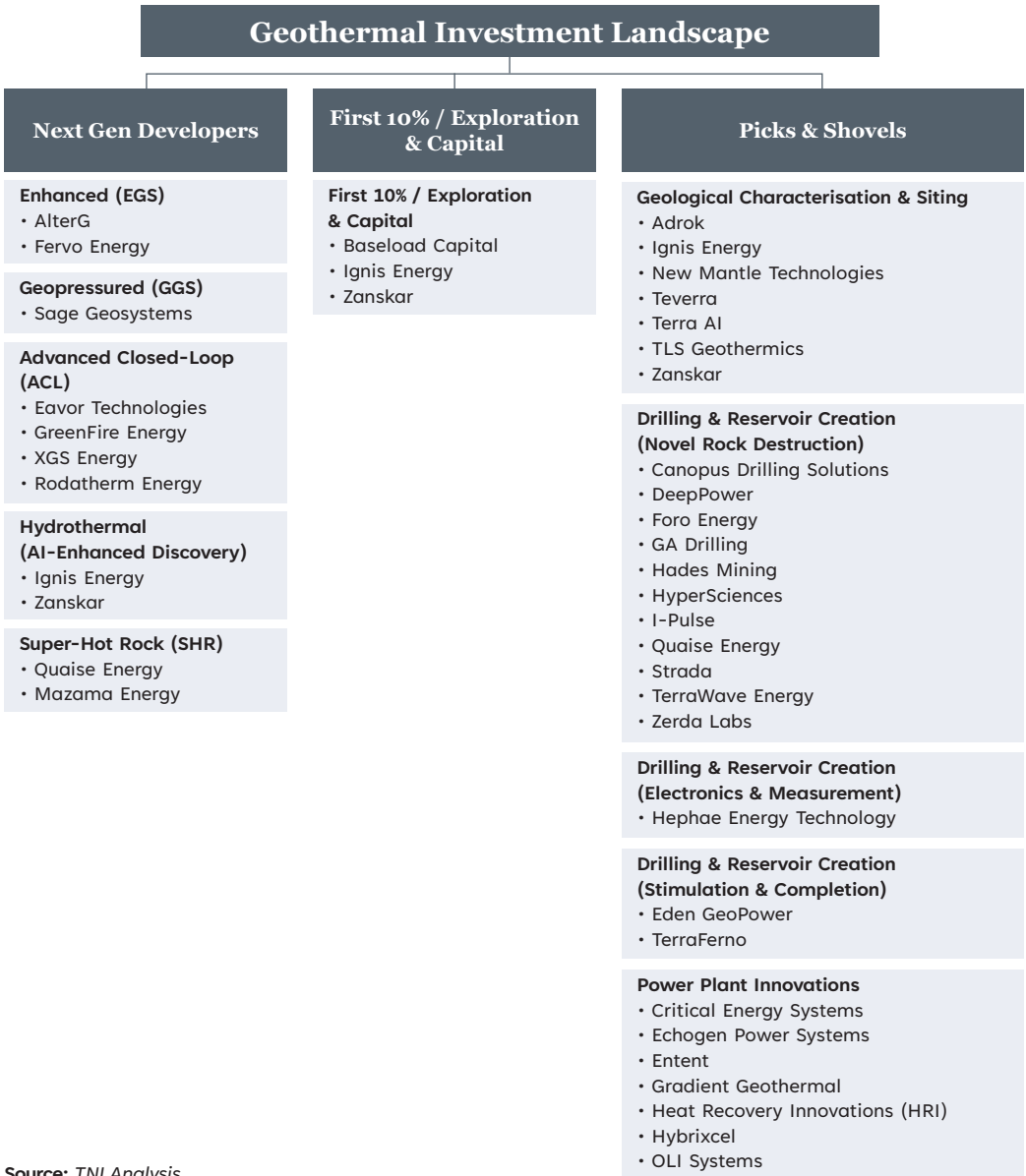
Investing in developers carries the highest concentration of technology, execution and capital risk within Next-Generation Geothermal due to the structural challenges around defining the pace of development including complexity of the multi-rig, multi-well platform development complicated by the lack of large-scale organisational resources and capital, with additional complications of technology execution in the early stage. Learning from the shale industry reveals that this complexity can best be managed through the early creation of a large land bank (geothermal leases), with focused staged project de-risking, strategic partnerships with oil majors or integrated hydrothermal companies, and access to large amounts of low-cost capital. Economies of scale exist primarily at the regional platform level, rather than global corporate scale.

So we would expect to see multiple large-scale competitors who gradually grow more agnostic as to technology and diversify their technology expertise across traditional geothermal to various forms of next generation technologies but starting with a core technology focus. So, no winner takes all.

When investing in developers, we favour those with large, high-quality land banks that combine attractive acreage, but generally expect full value chain geothermal development companies like Fervo to be among the highest risk ways to invest in the space, with high returns dependent on early exits to O&G or integrated players before such large well financed incumbents elect to enter the Next-Generation Geothermal market after the technology has been proven by pioneers such as Fervo.

Exhibit 59

Three NGG Investment Strategies – potentially deployed in concert with each other



Source: TNI Analysis

Where does NGG sit relative to other energy transition technologies as an investment opportunity today?

The timing of investment depends on the cost of capital and nature of the capital. The current moment in time would appear to coincide with the early growth equity stage of investment. In other words, we are leaving

the early stage where venture capital's cost of capital corresponds with the risk. We are seeing the beginning of project finance and growth equity investors but still remain far away from seeing lower cost of capital structures including infrastructure investors and banks.

NGG sits in a somewhat unique position

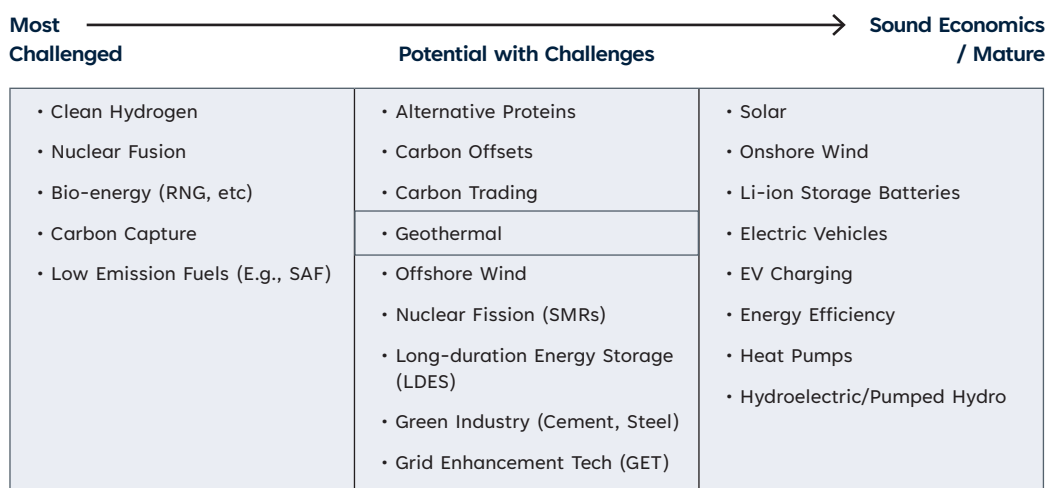
today across the spectrum of energy transition technologies aiming to address the global decarbonisation challenge. Solar, wind, grid-tech, EVs and batteries are all mature technologies today. At the other end of the technology spectrum, hydrogen, CCUS, nuclear fusion and long duration energy storage options (LDES) appear to require significant government policy support to break through their current stages of

development to find sounder financial footing – with notable exceptions.

As you can see in Exhibit 60, we see Geothermal as one of the most promising of unproven technologies among energy transition technological breakthrough opportunities. Geothermal has US government support as well as policy support in Europe, Japan and other major economies.

Exhibit 60

Geothermal sits among a relatively short list of potential technologies that can break through to long-term economic viability with or without policy support



Source: TNI analysis

Lessons from the Shale Industry that inform our investment recommendations: Land, speed, and capital matter most

As we have discussed above, the development of the shale gas industry demonstrated that technological breakthroughs alone rarely determine long-term winners. Instead, enduring value tends to accrue to platforms that combine technological capability with control over high-quality resource positions (i.e., land leases) and access to capital. A similar dynamic is already emerging in Next-Generation Geothermal. The following five investment insights guide our investment strategy recommendations to follow.

- 1) **Platform value will accrue to developers that combine technical validation with valuable landbanks:** The primary value driver is not simply proving technology but pairing repeatable well results with ownership of high-quality land positions. Developers that secure attractive acreage early and demonstrate commercial flow rates will be able to syndicate capital and bring in partners (across the value chain, including rigs, grid connection and off-takers) from a position of strength.
- 2) **Speed to technology de-risking is critical:** Access to low-cost capital to acquire sites and scale quickly creates

an early-mover advantage. More mature players such as Fervo are closer to project finance and, now, lower cost public equity capital and are therefore better positioned to secure premium acreage, long-lead equipment and grid interconnection capacity. Bottlenecks in rigs, ORC turbines and transmission access reinforce this dynamic and favour developers that reach commercial maturity first.

3) **Oil and gas majors are likely future acquirers rather than competitors:**

Large oil and gas companies are unlikely to commit significant internal capital until technology and economics are proven at scale. Entry is therefore more likely to occur through acquisitions of mature, de-risked platforms. For early investors, this represents a credible long-term exit pathway.

4) **Over time, value is likely to concentrate in the service providers:**

As the sector scales, proprietary drilling systems, well completion tools and subsurface technologies may capture durable margins. Once validated, these assets are natural acquisition targets for established oilfield services firms (such as SLB, Halliburton and Baker Hughes) seeking to internalise expertise and defend market position and do not rely on any one technology succeeding over others. In short, this “Picks & Shovels” strategy hedges out the risk of backing the wrong developer.

Below, we lay out our three geothermal investment strategies, which reflect these lessons from the shale revolution.

NGG Investment Strategy #1: Next-Generation Geothermal Developers

We favour EGS as the core technology allocation, but would not rule out ACL, GGS and SHR developers in a portfolio of “horses for courses” technologies. The investment thesis is not about backing a long-term

standalone winner. We expect the sector to fragment rather than consolidate around a single champion. Any investment in an early stand-alone developer, ideally, needs to be timed carefully, buying before the technology is derisked and selling after it is derisked, most likely exiting through an IPO or sale to an incumbent geothermal company like Ormat or oil & gas major like Chevron, BP or Shell (following the Mitchell/Devon/XTO pattern in shale). We do not rule out the prospect that the leading NGG developers manage to scale their resources and capital sources to rival what long established oil majors could achieve with the derisked NGG technology.

The developers most likely to command a premium exit will be those who combine a large, high-quality land bank with repeatable well economics, focussed staged project de-risking, and strategic partnerships with the very incumbents most likely to acquire them. The exit pathway is not entirely in the developer’s control. The timing of oil & gas major entry into NGG will depend on when geothermal IRRs become competitive with fossil fuel development returns, which at present still favour oil & gas at 25–30% versus geothermal’s projected 10–15%. If that gap narrows more slowly than expected — because drilling costs decline more gradually or because fossil fuel returns remain elevated — the exit window may take longer to open, extending the hold period and compressing investor returns. High returns are dependent on entering at attractive valuations and, critically, on the pace at which the technology proves out and draws incumbents in. Of the three geothermal investment strategies we lay out here, this carries the most concentrated risk and the widest range of outcomes.

Investing in developers is challenging, with no dominant leader

Next-Generation Geothermal development is hard, really hard, even for veteran oil & gas operating executives. Unlike oil and gas — where a single discovery well can pay for an entire exploration programme — geothermal has a structurally capped upside per well,

typically 7.5 to 10 MW bounded by the local heat gradient and the fraction of that heat that can be captured (the enthalpy ratio). The economics therefore depend on drilling many wells reliably and repeatably, not on a single step-change outcome.

What has to be done to make it profitable is hard and complicated. To scale at a pace that creates a meaningfully large business in a profitable time frame, the management team needs to manage multiple rigs over multiple sites at the same time over many years. The arithmetic is demanding even at Fervo's stated productivity of approximately 100 MW of capacity added per rig-year: powering a single 1 GW data centre, the kind being announced today, entirely from geothermal implies roughly ten rig-years of dedicated drilling, equivalent to two rigs running continuously for five years or four rigs for two and a half. Fervo has indicated it can scale from running two rigs simultaneously to at least five, adding ~0.5 GW per year at full deployment. The disciplined response to that scale challenge is a stage-gated ramp, typically 5 MW pilot, 20 MW demonstration, then phased build to 200 MW commercial scale, with explicit go/no-go criteria at each stage. Investors should expect, and arguably require, this kind of structured ramp. It is the principal mechanism by which subsurface, drilling and offtake risks can be progressively retired before each subsequent capital commitment, and it is what separates developers that will reach commercial scale from those that will run out of capital trying.

Next-Generation Geothermal development has advanced more slowly than many expected, with nearly all projects remaining at the demonstration or early commercial-pilot stage. While Fervo has achieved important milestones, including commercial-scale horizontal well-pair testing and non-recourse project financing for Cape Station, true utility-scale, bankable operations at meaningful scale lie in the future, not present, across the sector. This extended timeline introduces a material risk that NGG could deliver only modest risk-adjusted returns (<10% IRR) for the foreseeable

future, unless significant breakthroughs in drilling efficiency, reservoir performance, or system economics accelerate commercial deployment.

While developers like Fervo and Zanskar show promise, geothermal is unlikely to evolve into a winner-takes-all market. Regional fragmentation—driven by highly variable local geology and resource types, combined with country-specific permitting (3–5+ years in the U.S., environmental delays of 2+ years in Europe) and interconnection bottlenecks (queues exceeding 1 TW in the U.S.), precludes any single player from scaling rapidly and dominating. Instead, we envisage a landscape of numerous localised developers serving specific regional needs in a fundamentally local electricity business that cannot be shipped globally like oil or gas.

The shale-fracking experience illustrates why sustained consolidation or monopoly formation is improbable. Rapid innovation drove the boom, but no firm maintained a technological monopoly for long. Best practices diffused quickly through third-party service providers, commoditising key advantages within 1–2 years. The largest and most durable economic value accrued disproportionately to integrated oilfield service providers. In contrast, exploration and production (E&P) operators bore geological risk, commodity price exposure, and high capital intensity. While some operators excelled at execution—securing prime acreage, optimising financing, managing risk and insurance, streamlining timelines, and repeating processes to scale early—they faced eroding edges as competition intensified and advantages commoditised.

Fervo's leadership in enhanced geothermal systems (EGS) does not guarantee long-term dominance. As the frontrunner, Fervo has delivered impressive milestones: Cape Station Phase I remains on track for commercial operations by the end of 2026, backed by substantial funding and major offtake agreements. This positions Fervo as the most advanced in scaling commercial EGS, internalising drilling efficiencies, reservoir

management learnings, and execution expertise drawn from oil and gas analogues. In short, Fervo’s execution excellence enables significant near-term scaling and value creation, but the sector’s inherent variability, diffusion of learnings, and localised economics favour a diverse landscape of specialised operators rather than sustained dominance by any one developer. This reinforces why bets on individual developers carry concentrated risk compared to more diversified plays.

Clearly, we favour EGS developers as the core of a Next-Generation Geothermal allocation, but we would not rule out the possibility that ACL, GGS and SHR developers pivot to EGS in a portfolio of “horses for courses”

technologies. We also note that the capital concentration in Fervo and Eavor equity stakes may not fully appreciate the inherent market fragmentation among competitors likely to evolve in EGS. With that being said, below we evaluate the current major Next-Generation Geothermal competitors as investment opportunities.

Who are the leading developer investment candidates?

Exhibit 61 below simply profiles the seven most investable Next-Generation Geothermal developers across technology type, capital raised, estimated valuation, near-term project pipeline, and key partners.

Exhibit 61

Descriptions of Major Next-Generation Geothermal Developers

	Fervo	Sage	Mazama	Eavor	XGS	Zanskar	Quaise
Technology	EGS	GGS	SHR	ACL	ACL	AI-Enhanced	SHR
Founded / HQ	2017 / Houston, TX	2020 / Houston, TX	2023 (merger) / Portland, OR	2017 / Calgary, AB	2023 / Palo Alto, CA	2018 / San Francisco, CA	2018 / Cambridge, MA
Capital Raised	~\$3.4B	~\$130M	~\$30M	~\$700M+	~\$20M	~\$180M (\$115M Series C, Jan 2026)	~\$75M
Post-Money Valuation	\$7.6B	~\$100–150M (est.)	~\$100–150M (est.)	~\$600M–1.0B (est.)	~\$80–100M (est.)	~\$500–700M (est.)	~\$250–400M (est.)
Near-term Pipeline	Cape Station, UT — 100 MW Phase 1 (Late 2026); 400 MW Phase 2 (2028); 2 GW	SMECI Christine, TX (ERCOT); U.S. Air Force demo (Starr County, TX); Ormat commercial facility (Western US, late 2026–2027)	Newberry, OR — 15 MW pilot, then 200 MW commercial	Geretsried, Germany (Loops 2–4, 2026–28); Alberta projects	Meta/PNM 150 MW, NM — 5 MW by ~2027; full 150 MW by 2029	Lightning Dock, NM (operating); Pumpnickel, NV; Big Blind, NV (100+ MWe potential)	1 km field drill, TX (2026); Pilot plant, Western US (~2028)
Key Partners	Google, SCE, Meta, Devon Energy	Meta, Ormat, SLB, USAF	DOE, Khosla Ventures	OMV, SCP, BP, Chevron	Meta, Baker Hughes, PNM	Ormat, Freeport-McMoRan	Nabors

Source: Company disclosures, PitchBook & Supplemented with TNI research

Which developers have made the most progress in derisking their technology?

Exhibit 62 details each developer’s current development stage: what has physically been built or drilled, the pathway to commercial scale, and the timeline for first production

of more than 5 MW of electricity — whether delivered to the grid or produced off-grid. We view this >5 MW threshold as the clearest single marker of commercial viability, separating developers with validated, scalable systems from those still at demonstration stage.

Exhibit 62

Developer Development Stage & Commercial Pathway

Developer	Revenue / Grid Status	What Has Been Built / Drilled	Path to Commercial Scale	First >5 MW Electricity Production
Fervo	Revenue-generating. Project Red (Google pilot, NV): 3.5 MWe delivered to grid since Nov 2023 via NV Energy for Google’s Nevada data centers. Cape Station (Beaver County, UT): Phase 1 drilling complete, first commercial power expected late 2026.	Project Red: 2 horizontal EGS wells producing 3.5 MWe net, confirmed 24/7 baseload (2023). Cape Station: 15+ wells drilled across multiple horizontal pairs; drilling times reduced to sub-20 days.	Cape Station Phase 1: 100 MWe by late 2026. Phase 2: 400 MWe by 2028 (500 MWe total). 320 MWe under PPA with SCE; 115 MWe via NV Energy for Google.	Achieved — 3.5 MWe net to grid (Nov 2023)
Sage	Revenue-generating (energy storage). 3 MW energy storage facility at San Miguel Electric Cooperative (SMECI) site in Christine, Texas — co-located with a retiring 410 MW coal plant — commissioned 2025 and began selling electricity to the grid. First geothermal power generation project still ahead.	SMECI: 3 MW storage facility commissioned, grid-connected. Starr County well and SMECI pilots achieved 10x improvement in power output well-to-well. Series B: \$97M+ raised Jan 2026 (co-led by Ormat and Carbon Direct Capital).	Meta Phase I: 4–8 MWe (COD late 2027). Meta Phase II: 150 MWe (COD 2030), with option for additional 200 MW. DoD: U.S. Air Force geothermal demonstration. Fortune 500 utility: 10–12 MW storage tolling agreement. International: Lithuania, Australia, Romania.	Expected late 2027 — Meta Phase I (4–8 MWe)
Mazama	Pre-revenue. 15 MWe pilot (Newberry Volcano, central Oregon) targeting first power 2026–27. No offtake agreements announced.	Pilot wells completed 2025. Record 629°F (331°C) bottomhole temperature achieved Oct 2025. Circulation between two wells validated. Targeting 750°F (400°C) in 2026 drilling campaign.	15 MWe pilot (2026–27) to 50+ MWe commercial expansion.	Expected 2026–27 — 15 MWe pilot
Eavor	Revenue-generating. Eavor-Loop™ (Geretsried, Germany): first closed loop commissioned Dec 2025; delivering 8.2 MWe of electricity to the German grid and 64 MW thermal to local district heating network.	Geretsried: Loop 1 operational (4.2 km depth), generating power and heat. Loop 2 construction planned from March 2026. Eavor-Lite™ demo (Rocky Mountain House, AB): 2-well proof-of-concept validated closed-loop flow (2022).	Geretsried: all 4 loops by 2027 (~32 MWe equivalent). 320 MWe pipeline across Europe (Germany, Finland). US projects under evaluation.	Achieved — 8.2 MWe to grid (Dec 2025)

Developer	Revenue / Grid Status	What Has Been Built / Drilled	Path to Commercial Scale	First >5 MW Electricity Production
XGS Energy	Pre-revenue. Operating closed-loop geothermal pilot at Coso, California (>1,000m depth). 3,000-hour continuous operation milestone achieved 2025.	Closed-loop, water-independent geothermal system validated at Coso. Pilot well drilled to >1,000m depth. Partnerships with Meta, Baker Hughes, and CC Power for future deployment.	Coso pilot to commercial-scale deployment. Targeting utility partnerships for first >5 MWe projects.	Expected ~2027–28
Zanskar	Revenue-generating. Lightning Dock (NM): acquired and repowered to full 15 MWe capacity; generating power to grid.	Lightning Dock: 15 MWe conventional hydrothermal facility, fully operational. AI exploration: mapped sites across western US. Pumpnickel, NV: well drilled (137°C at 760m). Big Blind, NV: two intermediate wells drilled (Jul–Aug 2025); >100 MWe potential.	Lightning Dock: operational. Big Blind: targeting pilot production 2027–28 (>100 MWe potential). Asset-light exploration model transitioning to owner-operator.	Achieved — 15 MWe at Lightning Dock
Quaise	Pre-revenue. No grid connection or offtake. Earliest pilot project ~2030. Furthest from commercialisation.	Field-validated millimetre-wave (gyrotron) drilling to 118m depth (July 2025 field test). No full-scale borehole drilled. 1 MW field system planned 2026. Project Obsidian (Oregon) targeting 2030 commercial operation.	1 MW field system (2026) to pilot borehole to 10+ km to repowered fossil fuel plant for SHR steam. Commercial: ~2030 (Project Obsidian).	Expected ~2030

Source: Company disclosures, PitchBook & Supplemented with TNI research

Of the seven developers, four are generating revenue (Fervo, Eavor, Zanskar, and Sage from energy storage), though only three are producing geothermal electricity. These four represent the most de-risked near-term investment opportunities in NGG.

Investment conclusions for each major geothermal developer

Fervo is the furthest ahead, and just leapt even further ahead by securing \$1.9B in new equity capital from the public markets. It is the only developer to have drilled, stimulated, and operated commercial-scale horizontal well pairs for NGG electricity production. Its Project Red (2023) used one horizontal well pair (two wells, plus one vertical monitoring well) to produce ~3.5 MWe of grid power via NV Energy for Google’s Nevada data centers, confirming 24/7 baseload capability.

Fervo has since drilled more than 15 wells (including multiple additional horizontal pairs) at Cape Station (Utah) — the first true utility-scale NGG project — with Phase 1 (100 MWe) targeting first power in late 2026 and full build-out to 500 MWe by 2028.

Sage has taken a different path to early revenue. Its 3 MW energy storage facility at the San Miguel Electric Cooperative (SMECI) site in Christine, Texas — co-located with a retiring 410 MW coal plant — was commissioned in 2025 and is selling electricity to the grid, making Sage the first pressure geothermal company to generate commercial revenue. However, Sage’s first geothermal power generation project is still ahead: Meta Phase I (4–8 MWe) targets commercial operation in late 2027, with Phase II (150 MWe) targeting 2030 and an option for an additional 200 MW thereafter.

The company raised \$97M+ in Series B funding in January 2026, co-led by Ormat Technologies and Carbon Direct Capital. Sage also holds contracts with the U.S. Department of Defense (including a U.S. Air Force geothermal demonstration), a tolling agreement with a Fortune 500 utility for 10–12 MW of energy storage, and international partnerships in Lithuania, Australia, and Romania.

Eavor is the third. Its Geretsried project in Germany commissioned its first closed loop in December 2025 and is already delivering 8.2 MWe of electricity to the German grid and 64 MW of thermal energy to the local district heating network, making Eavor the first closed-loop geothermal company to achieve commercial-scale power generation. Loop 2 construction is planned from March 2026, with all four loops expected to be operational by 2027 producing ~32 MWe equivalent. Eavor's 320 MWe European pipeline (Germany, Finland) provides further scale optionality.

Zanskar is already generating revenue from its Lightning Dock facility in New Mexico which it acquired and repowered to full 15 MWe capacity. While Lightning Dock is a conventional hydrothermal asset rather than next-generation technology, it is commercially operational and provides Zanskar with cash flow while it pursues its NGG exploration programme. Beyond Lightning Dock, Zanskar's AI-driven exploration platform has mapped sites across the western US, and drilling at priority prospects (Pumpnickel and Big Blind, Nevada — the latter with >100 MWe potential) confirmed viable resources in 2025, targeting first NGG pilot production in 2027–28.

The remaining three developers are at demonstration or early-pilot stage. Mazama has confirmed a high-temperature EGS resource at Newberry Volcano in central Oregon — achieving a record 331°C bottomhole temperature in October 2025 —

and targets a 15 MWe pilot in 2026–27 but has no offtake agreements.

XGS completed a 3,000-hour closed-loop pilot at Coso, California in 2025, validating its water-independent geothermal system at >1,000m depth, but has not yet reached commercial-scale power production.

Quaise remains furthest from commercialisation, having field-validated its millimetre-wave drilling concept (to 118m depth in a July 2025 field test) with a 1 MW field system planned for 2026 and its Project Obsidian in Oregon targeting commercial operation by ~2030.

A commercial pilot at any of these three early-stage development companies is typically a small-scale facility (<10 MW) designed primarily to validate the full system in real-world conditions. They are not yet a bankable, utility-scale power plant. This underscores that very little true commercial-scale NGG electricity production has been achieved to date.

Techno-economic analysis of major NGG developers

Moving on from the above discussion on stage of development, Exhibit 63 compares the seven developers across techno-economic factors including technology readiness, subsurface execution risk, cost and storage capability. The figures in the table below reflect projected levelised cost of energy at full technological maturity. They do not capture the potential revenue premium from dispatchability or storage. This distinction matters particularly for Sage, whose GGS architecture enables long-duration energy storage alongside baseload generation. A flat LCOE comparison understates Sage's economic proposition: the ability to store energy during low-price periods and discharge at peak demand could generate a meaningful revenue uplift relative to baseload-only geothermal.

Exhibit 63

Major Next-Generation Geothermal developers' techno-economic comparison

Colour-coding reflects relative risk/readiness: Green = favourable; Yellow = moderate; Orange = elevated; Red = high risk / early stage.

Company	TRL	Low Enthalpy Risk	Execution Risk	Water Consumption	Seismic Risk	Cost (LCOE)	Storage Capability
Fervo (EGS)	6-7-Cape Station demonstrated 3.5 MW from single well pair; no large commercial plant yet	Low / Mod. - Targets low-perm sedimentary/ basement rock; similar siting flexibility to Sage	Mod. / High - Key elements demonstrated but no large commercial operations; reservoir longevity unproven	Moderate - Open-loop; ~10% water loss through adsorption into fractured rock; continual replenishment needed	Moderate - Hydro-shear stimulation can induce M3+ events; water losses can connect to basement-rooted faults	\$75-115/MWh - Competitive at scale; benefits from O&G drilling efficiencies	Limited Base-load power; limited flexibility in adjusting well flowrates
Sage (GGS)	4-5-Storage TRL 6; power gen TRL 4-5; HeatRoot reservoirs not demonstrated at commercial scale	Low / Mod. - Seeks low-perm formations with no fault presence; greatly expands siting flexibility	Mod. / High - Gravity-fracturing less demonstrated than high-pressure EGS; surface equipment for high-pressure ops not validated at scale	Low - Volumes much smaller than open EGS; fluids recycled; losses estimated <2%	Low - Lower-pressure gravity-assisted process; avoids faults through downward directionality of reservoir	\$75-115/MWh - Promising but unproven at commercial scale	Dispatchable Base-load and dispatchable; can store and release energy on demand
Mazama (EGS)	5-6-AltRock / Blade joint venture (2023) combined EGS reservoir engineering with directional drilling; Newberry demo site	Low / Mod. - Targets similar formations to Fervo; benefits from Blade's subsurface. Characterisation tools	Mod. / High - Similar EGS approach to Fervo; less advanced field demonstration history	Moderate - Open-loop EGS requiring water injection and ongoing management similar to Fervo	Moderate - Hydro-shear approach with comparable risk profile to conventional EGS	TBD - Limited public cost data; early-stage commercial development	Limited - Base-load-oriented EGS; similar operational profile to Fervo
Eavor (ACL / Closed Loop)	6-7 - Geretsried commercial pilot (Germany) operational; well completion at greater depths not demonstrated at commercial scale	Low - Requires only hot rock; essentially no geologic preclusions	High - Requires enhanced drilling techniques, connections, and new well materials at depth; not demonstrated at commercial scale	Low - Closed-loop system; minimal to no water make-up required; initial fill comparably small	Low - Fully closed system; no fracturing or high-pressure fluid injection into subsurface rock	\$120-180/MWh - Higher cost due to extensive drilling requirements (tens of thousands of feet of casing)	Limited Base-load power; limited flexibility in turning well flowrates or cycling wells
XGS (ACL / Closed Loop)	4- Commercial pilot (California); closed-loop concept at early stage	Low - Requires only hot rock; broad siting flexibility	High - Faces same drilling and completion challenges at depth as Eavor	Low - Closed-loop; minimal water requirements	Low - Closed-loop; no fracturing or injection	\$120-180/MWh - Similar cost challenges from extensive drilling	Limited Base-load with some cycling capability

Company	TRL	Low Enthalpy Risk	Execution Risk	Water Consumption	Seismic Risk	Cost (LCOE)	Storage Capability
Zanskar (AI-Enhanced Discovery)	8-9 / 5-6 Plant ops TRL 8-9; AI toolkit TRL 5-6; partners with conventional operators	Moderate - AI tool reduces exploration risk but still depends on subsurface geological conditions	Moderate Technical risk embodied in associated generation technology; drilling risk marginal but execution history narrow	Low - Does not influence water dependence of associated technology	Low / Mod. - Partnering with Zanskar could lower seismicity risk through identification and avoidance of faults	\$80-120/MWh Depends on partner technology economics	Limited Baseload power; limited turnaround / flexibility
Quaise (SHR)	3 - Millimetre-wave drilling in lab testing only; no field demonstrations yet	Low / Mod. - Targets deeper hot rock with more globally uniform temperature distribution; lithologies differ	High - Deep-well mm-wave drilling and interface with super-hot resources remain high risk and unproven even in field demos	Uncertain - Deep SHR may require more water at start; lower amounts if system remains closed	Mod. / High - If using EGS mechanisms at increased depth, elevated risks of triggering fault slip	TBD - Potential for very low cost at scale but entirely unproven	Undemonstrated - Operational flexibility not yet demonstrated

Source: TNI analysis

Five key conclusions emerge from this techno-economic comparison.

1. EGS developers Fervo, Mazama and Sage offer the most competitive projected LCOE (\$75-115/MWh), but this comes with moderate-to-high execution and seismic risk. The open-loop approaches that make EGS cost-effective also introduce water management, re-stimulation risk and seismic risk that closed-loop systems avoid entirely. Heat dissipation risk varies across technologies but is relevant to all.
2. Advanced Closed-Loop developers (Eavor, XGS) are the cleanest from an environmental and permitting perspective — no fracturing, minimal water use, negligible seismic risk — but their LCOE estimates (\$120-180/MWh) remain materially above EGS, and economic viability hinges on drilling cost breakthroughs that have not yet materialised.
3. Sage is the only developer offering genuine dispatchability and storage optionality, which a flat LCOE comparison understates: the ability to store energy during low-price periods and discharge at peak demand could generate a meaningful revenue uplift relative to baseload-only geothermal.
4. Zanskar occupies a distinct category — its value is not in generation technology but in exploration de-risking, and its economics ultimately depend on whichever partner technology it deploys.
5. Quaise's TRL 3 rating and lack of field demonstrations place it furthest from commercial viability, though its theoretical upside (5-10x power density per well at SHR depths) is the highest in the table if the drilling technology proves out.

Following on from the analysis of development stage and techno-economic comparisons, below we provide high level overall investment assessment, again, ignoring management quality, capital availability and other factors that would normally be considered in a full due diligence

exercise. This should provide for a useful starting point for company specific due diligence. At some risk to our credibility, we venture to rank order these companies on the basis of investment attractiveness and explain that ranking on the basis of our pros and cons summarised below.

Exhibit 64

Summary Investment Assessment of NGG Developers (ranked from most to least attractive)

Fervo Energy (EGS)



Investment Assessment	Key concerns
<p>A highly successful public flotation has provided a major leap ahead of its competition.</p> <p>Most advanced EGS developer with the strongest commercial proof points in the sector. Only NGG company to have drilled, stimulated, and operated commercial-scale horizontal EGS well pairs for grid-connected electricity.</p> <p>Revenue-generating since November 2023 — Project Red delivers 3.5 MWe to grid via NV Energy for Google's Nevada data centers, confirming 24/7 baseload capability.</p> <p>Demonstrated O&G-style learning curve: ~70% drilling time reduction and well cost decline from \$9.4M to \$4.8M at Cape Station, validating the thesis that EGS costs follow shale-like experience curves.</p> <p>Heavily de-risked offtake: PPAs with Google (115 MWe) and Southern California Edison (320 MWe) provide contracted revenue visibility through the development phase. Corporate backing from Devon Energy.</p> <p>Cape Station is the sector's bellwether project: Phase 1 (100 MWe) targeting late 2026, full build-out to 500 MWe by 2028. If Phase 1 delivers at projected economics, it validates the commercial thesis for EGS as a whole.</p>	<p>Reservoir longevity at scale remains unproven — no EGS project globally has demonstrated multi-year reservoir performance under continuous commercial cycling. Thermal drawdown rates over 10–20 year well lives are modelled, not observed.</p> <p>Water management and induced seismicity are ongoing technical and permitting risks. ~10% fluid loss through adsorption into fractured rock requires continual replenishment; M3+ seismic events have been documented at other EGS sites globally. Both constrain site selection and social licence.</p>



Investment Assessment	Key concerns
<p>AI-first exploration model that reduces dry-hole risk by targeting “blind” hydrothermal resources — geothermal systems with no surface expression that conventional exploration methods frequently miss. Zanskar’s platform integrates machine learning with geological, geophysical, and geochemical data to identify high-probability sites before drilling.</p> <p>Three major resource discoveries in a single year (Lightning Dock repowering, Pumpnickel, and Big Blind — the first blind geothermal find in 30+ years), demonstrating repeatable AI-driven exploration success and a >80% hit rate versus 50–60% for traditional methods.</p> <p>Revenue-generating: acquired and repowered Lightning Dock (New Mexico) to full 15 MW capacity — Zanskar’s first owned and operated asset, providing operational cash flow while the NGG exploration programme matures.</p> <p>Transitioning to integrated owner-operator model, with drilling underway at Pumpnickel (137°C at 760m confirmed) and Big Blind (Nevada, >100 MW potential, two intermediate wells drilled mid-2025). This positions Zanskar to capture development-stage value rather than selling discoveries to third parties.</p> <p>Well-capitalised: \$115M Series C (January 2026); \$180M raised in total. Partnerships with Ormat and Freeport-McMoRan validate the platform and provide access to operational data, project sites, and development expertise.</p> <p>Technology-agnostic platform applicable across conventional, EGS, ACL, and closed-loop approaches, maximising addressable market regardless of which subsurface technology ultimately dominates.</p>	<p>Durability of AI exploration advantage is the central investment question. Zanskar’s >80% hit rate is a meaningful edge today, but the underlying approach — applying machine learning to publicly available geological, geophysical, and remote sensing data — is methodologically replicable. As geothermal exploration datasets grow and AI tools become more accessible, the barrier to entry for competitors (including well-resourced incumbents like Ormat, geological survey agencies, and O&G majors with extensive subsurface data libraries) will decline. Zanskar’s moat depends on proprietary training data, model sophistication, and speed of iteration — all of which are defensible but not permanent. The question is whether Zanskar can convert its current exploration lead into a portfolio of owned resource positions before the AI advantage narrows.</p> <p>Owner-operator transition risk: Zanskar’s proven capability is in AI-driven exploration and resource identification. Developing, constructing, and operating power plants at scale requires a fundamentally different skill set — EPC management, power plant engineering, grid interconnection, and long-term O&M. Lightning Dock demonstrates early capability, but scaling from one acquired conventional asset to a portfolio of developed NGG projects is a material organisational step-up</p>



Investment Assessment	Key concerns
<p>AI-first exploration model that reduces dry-hole risk by targeting “blind” hydrothermal resources — geothermal systems with no surface expression that conventional exploration methods frequently miss. Zanskar’s platform integrates machine learning with geological, geophysical, and geochemical data to identify high-probability sites before drilling.</p> <p>Three major resource discoveries in a single year (Lightning Dock repowering, Pumpnickel, and Big Blind — the first blind geothermal find in 30+ years), demonstrating repeatable AI-driven exploration success and a >80% hit rate versus 50–60% for traditional methods.</p> <p>Revenue-generating: acquired and repowered Lightning Dock (New Mexico) to full 15 MW capacity — Zanskar’s first owned and operated asset, providing operational cash flow while the NGG exploration programme matures.</p> <p>Transitioning to integrated owner-operator model, with drilling underway at Pumpnickel (137°C at 760m confirmed) and Big Blind (Nevada, >100 MW potential, two intermediate wells drilled mid-2025). This positions Zanskar to capture development-stage value rather than selling discoveries to third parties.</p> <p>Well-capitalised: \$115M Series C (January 2026); \$180M raised in total. Partnerships with Ormat and Freepport-McMoRan validate the platform and provide access to operational data, project sites, and development expertise.</p> <p>Technology-agnostic platform applicable across conventional, EGS, ACL, and closed-loop approaches, maximising addressable market regardless of which subsurface technology ultimately dominates.</p>	<p>Durability of AI exploration advantage is the central investment question. Zanskar’s >80% hit rate is a meaningful edge today, but the underlying approach — applying machine learning to publicly available geological, geophysical, and remote sensing data — is methodologically replicable. As geothermal exploration datasets grow and AI tools become more accessible, the barrier to entry for competitors (including well-resourced incumbents like Ormat, geological survey agencies, and O&G majors with extensive subsurface data libraries) will decline. Zanskar’s moat depends on proprietary training data, model sophistication, and speed of iteration — all of which are defensible but not permanent. The question is whether Zanskar can convert its current exploration lead into a portfolio of owned resource positions before the AI advantage narrows.</p> <p>Owner-operator transition risk: Zanskar’s proven capability is in AI-driven exploration and resource identification. Developing, constructing, and operating power plants at scale requires a fundamentally different skill set — EPC management, power plant engineering, grid interconnection, and long-term O&M. Lightning Dock demonstrates early capability, but scaling from one acquired conventional asset to a portfolio of developed NGG projects is a material organisational step-up</p>



Investment Assessment	Key concerns
<p>Asymmetric risk/reward at low entry cost. At ~\$30M raised, Mazama is the smallest-capitalised developer in this table but offers potentially the highest return multiple for investors willing to underwrite early-stage SHR exposure.</p> <p>Two structural advantages: pursues SHR using advanced conventional directional drilling in high-gradient volcanic regions where supercritical temperatures (>374°C) are accessible at shallower depths (~4–8 km) — avoiding the need for unproven novel drilling technologies (cf. Quaise) — and the Newberry Volcano (central Oregon) site benefits from extensive DOE-funded subsurface data that meaningfully reduces exploration risk.</p> <p>Strong technical foundation: formed from the 2023 joint venture between AltaRock Energy (EGS reservoir engineering, 15+ years at Newberry) and Blade Energy Partners (directional drilling expertise). 15 granted patents. Achieved a record 629°F (331°C) bottomhole temperature in October 2025; targeting 750°F (400°C) in 2026.</p> <p>Potential acquisition target for a larger developer seeking SHR capabilities and an established site position at relatively low entry cost.</p>	<p>TRL 3: SHR reservoir engineering at supercritical conditions is unproven at commercial scale. Successfully stimulating and sustaining supercritical fluid flow presents distinct challenges from conventional EGS — corrosion, well integrity, and thermal cycling under extreme conditions are open engineering problems.</p> <p>Smallest capital base (~\$30M) limits pace of development relative to better-funded peers and creates financing risk if the 2026 drilling campaign requires additional capital before demonstrating commercial viability.</p> <p>Geographic concentration around high-gradient volcanic sites narrows the addressable market compared to Quaise's “anywhere on Earth” thesis. No offtake agreements secured.</p>



Investment Assessment	Key concerns
<p>Earlier-stage closed-loop bet with a differentiated technical thesis that, if validated, could meaningfully shift closed-loop economics. The core proposition is a proprietary thermally conductive material designed to improve heat transfer efficiency by 30–50%, directly addressing the core physics limitation of ACL where conductive heat transfer through rock is inherently slower than convective flow in open-loop EGS.</p> <p>Key differentiator versus Eavor: if validated at scale, narrows the efficiency gap between closed-loop and open-loop approaches and could compress LCOE toward competitive levels without requiring Eavor’s extensive lateral drilling footage.</p> <p>Commercial traction building: 150 MW Letter of Intent with Meta; 3,000-hour continuous operation milestone at the Coso geothermal facility in California (2025); partnerships with Baker Hughes and CC Power.</p> <p>Least capitalised, steepest return gradient if the technology delivers. Founded 2023.</p>	<p>TRL 4; currently testing but lacks the field data and operational history of Eavor. The proprietary heat-transfer material is unproven at commercial scale and temperature — if it degrades under sustained high-temperature cycling, the core investment thesis collapses.</p> <p>Faces the same fundamental ACL challenge as Eavor — high drilling costs — and must demonstrate its efficiency advantage to justify a separate allocation. Without that differentiation, capital is better deployed with the more proven closed-loop operator.</p>



Investment Assessment	Key concerns
<p>Most prominent closed-loop developer and the first to achieve grid-connected commercial power from an ACL system globally. Eavor’s sealed underground thermosiphon circulates fluid through a closed loop without fracturing the reservoir, which entirely averts the seismicity and water-use risks that constrain EGS developers — a meaningful ESG and permitting advantage.</p> <p>Revenue-generating since December 2025: Geretsried (Germany) delivering 8.2 MW of electricity to the German grid and 64 MW of thermal energy to the local district heating network. Loop 2 construction planned from March 2026; all four loops expected by 2027 producing ~32 MW equivalent.</p> <p>320 MW European pipeline (Germany, Finland) provides further scale optionality.</p> <p>Substantially capitalised with strategic backing from BP and Chevron.</p> <p>European-first strategy is commercially rational for AGS specifically — Eavor’s closed-loop architecture is less gradient-sensitive than EGS, so the structural disadvantage Europe faces in EGS-for-power is materially smaller for AGS. Higher feed-in tariffs and strong district heating demand, and favourable permitting for non-fracking technologies improve near-term economics relative to US wholesale power markets where Eavor’s LCOE is less competitive.</p>	<p>LCOE of \$120–180/MWh is materially above EGS and conventional geothermal, driven by heavy reliance on extensive lateral drilling (tens of thousands of feet of casing per well). At the low end of IEA’s medium-cost EGS projections (\$70/MWh by 2050), Eavor’s current cost structure is 1.7–2.6x the target for competing technologies.</p> <p>Economic viability depends on drilling cost breakthroughs that have not yet materialised. Geretsried pilot performance data over the next 12–18 months is the critical proof point for whether closed-loop economics can converge toward competitiveness.</p> <p>European tariff dependency: current economics rely on above-market feed-in tariffs and district heating revenue that may not persist at scale or translate to lower-tariff markets. If Eavor cannot demonstrate a credible LCOE reduction pathway, the technology risks remaining confined to premium European environments.</p>



Investment Assessment	Key concerns
<p>Highest risk/reward profile in the table. Developing millimetre-wave (gyrotron) drilling technology to vaporise rock without physical bit contact, targeting depths of 10–20 km to access SHR temperatures (>374°C) virtually anywhere on Earth.</p> <p>Fundamentally a drilling hardware company — the thesis is that a step-change in drilling technology unlocks ubiquitous access to super-hot geothermal resources regardless of local geological gradient.</p> <p>If proven, genuinely transformational: supercritical fluid conditions at SHR depths deliver 5–10x the power density per well compared to conventional geothermal. Also enables repowering of retired fossil fuel plants with geothermal steam — a unique decommissioning value proposition.</p> <p>118m field demo conducted July 2025; 1 MW field system planned for 2026; Project Obsidian (Oregon) targeting commercial operation by ~2030. Partnered with Nabors Industries on rig integration. ~\$75M raised.</p>	<p>TRL 3; millimetre-wave drilling is unproven at the depths and sustained durations required for commercial geothermal wells. The gap between 118m demonstrated and 10+ km required is several orders of magnitude — each step deeper introduces new physics, materials, and engineering challenges.</p> <p>Materials science challenges at >374°C and extreme pressures extend beyond the drilling mechanism itself — well casing, completion hardware, and downhole instrumentation must all survive conditions that defeat conventional equipment.</p> <p>Longest path to commercialisation of any company in the table — likely 5–10+ years to a commercial plant. Earliest pilot ~2030.</p>

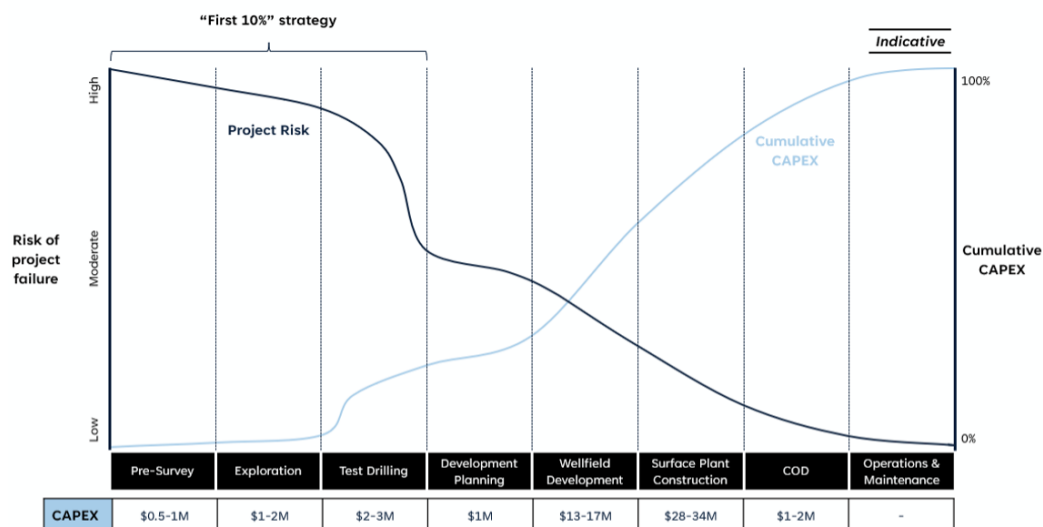
NGG Investment Strategy #2: First 10% of Geothermal Development

The “first 10%” of Enhanced Geothermal Systems (EGS) development—spanning pre-survey, exploration, and initial test drilling—represents a uniquely attractive but high-risk segment of the geothermal value chain. Although this phase typically accounts for only ~\$4–7M per site (roughly 10% of total project capex), it is where the most fundamental uncertainties are resolved: whether a viable subsurface resource exists, its scale, and whether it can be produced economically. Until these questions are answered, projects remain largely unfinanceable by traditional infrastructure investors, creating a structural capital gap that specialised, risk-tolerant investors are positioned to fill.

This early-stage focus underpins an emerging investment strategy: backing a geothermal-focused developer or infrastructure investor with core expertise in front-end resource validation. By concentrating capital and technical capabilities on the highest-risk stages, investors can “de-risk” projects before the much larger capital commitments required for full-scale development (typically \$30M–\$100M). Once a resource is proven through successful drilling and testing, the project undergoes a step-change in valuation—transitioning from speculative prospect to financeable infrastructure asset. At this point, it can be sold or recapitalised into lower-cost project finance structures.

Exhibit 65

The “first 10%” strategy in Next-Generation Geothermal focused on the pre-survey to test drilling stages which account for approximately 10% of the total project capex, but embeds the highest risk stages of development



Source: Ignis Energy; alfa8; TNI Analysis

The economics of this strategy are driven by a pronounced risk-reward asymmetry. For EGS-first practitioners, exploration success rates for first wells in greenfield projects are typically around 50%, with some estimates suggesting even lower rates for economically viable outcomes. The key question at the first well is not whether the heat is there (it almost always is) but whether a commercial flow rate can be created and sustained. Each unsuccessful well may result in a sunk cost of \$4–7M, making portfolio construction and risk diversification essential. A simplified illustration: a portfolio targeting a 50% success rate implies total upfront investment of \$8–14M per successful project, requiring exit valuations exceeding 2x site-level capex to achieve attractive returns.

Successful wells, defined by the flow rate after test drilling, can generate significant value uplift off the initial \$4 to 7M investment — often multiple times the initial investment — by unlocking access to cheaper capital and a broader pool of buyers. This strategy enables investors to “ride down the cost of capital curve.” Early-stage capital enters as high-

risk equity expecting returns in the range of 16–20%. Following successful de-risking, the asset can be transferred to infrastructure or project finance investor targeting 6–8% returns, reflecting the now-stable, long-duration cash flow profile. This transition creates a powerful arbitrage opportunity between high-risk development capital and lower-cost operational capital.

Technological innovation is increasingly enhancing the viability of this model. Advances in AI-driven geological targeting and subsurface modelling are significantly improving the precision of site selection and reducing dry-hole risk. By integrating geophysical, geological, and geochemical datasets, these tools can identify optimal drilling locations with greater confidence— even in “blind” settings without surface manifestations. This has already led to breakthrough discoveries and suggests that large, previously undetected geothermal resources may be accessible. In parallel, the evolution of EGS further shifts the risk profile by reducing dependence on naturally occurring permeability; instead, engineered

reservoirs allow developers to exert greater control over resource creation, moving risk from geology toward more manageable engineering challenges.

Taken together, the “first 10%” strategy represents a compelling niche within geothermal development. It concentrates capital where value creation is most significant, leverages technological advances to mitigate risk, and enables participation in a structural re-rating of assets. Companies like Ignis Energy exemplify this approach, focusing on early-stage development to unlock value before handing off to larger-scale infrastructure investors. For those equipped to manage geological uncertainty, this segment offers the potential for outsized returns and a critical role in scaling Next-Generation Geothermal energy.

NGG Investment Strategy #3: Enabling Technologies -- “Picks & Shovels”

The venture opportunity in NGG “Picks & Shovels” is concentrated in five sub-segments where incumbent tools are fundamentally inadequate for next-generation conditions: AI-driven subsurface characterisation and siting, novel rock destruction, high-temperature downhole electronics and measurement, and non-hydraulic stimulation. There are five attractive early to mid-stage companies raising capital as geothermal technology enablers with attractive prospects, despite the challenges faced by developers. These are evaluated below.

NGG “Picks & Shovels” investments comprise any component products and services sold to developers and operators of Next-Generation Geothermal platforms, with a focus on those which may have the greatest impact on the success of such operators as they grapple with the technological, economic and operational challenges highlighted above.

These specialised firms supply critical tools, sensors, drilling and completion services, stimulation technologies, and subsurface solutions. Rather than depending on ownership of geothermal resources or the success of any individual project or technology pathway, these businesses generate value by enabling the entire industry to scale. They capture benefits from widespread deployment across developers and technological approaches, independent of which players or methods ultimately prevail. Their market would ideally also extend to traditional geothermal, and even oil & gas.

Drilling and reservoir creation consumes 60–80% of NGG project capex and is where the overwhelming majority of “Picks & Shovels” value will be created. Power plant construction and operations represent 25–40%. Geological siting accounts for only 2–5% but is the highest-ROI spend — a small investment here fundamentally de-risks the far larger drilling commitment that follows.

Within drilling and reservoir creation, conventional services including rigs, casing, cement and mud, represent 65% of well costs but are controlled by incumbents with multi-decade fleet investments (Nabors, H&P, SLB) and are not venture-investable. The venture opportunity is concentrated in five sub-segments where incumbent tools are fundamentally inadequate for next-generation conditions: AI-driven subsurface characterisation and siting; novel rock destruction; high-temperature downhole electronics and measurement; non-hydraulic stimulation; and power plant innovation. Exhibit 66 lists the most attractive technology sub-segments of “Picks & Shovels” with examples of start-up companies aligned with each.

Exhibit 66

NGG Enabling Technologies (“Picks & Shovels”) — Core Sectors Overview

Sector	% of NGG Project Cost	Sub-Segments	Example Startups
A. Geological Characterisation & Siting	<5%	AI-driven subsurface characterisation and siting; reservoir modelling; subsurface imaging	Zanskar, Adrok, Terra AI, New Mantle Technologies,
B. Drilling & Reservoir Creation	60–80%	a. Novel rock destruction (plasma, mm-wave, laser)	GA Drilling, DeepPower, Quaise, Hades Mining, HyperSciences, Foro Energy, Canopus, Strada
		b. High-temperature downhole tools, electronics and measurement (>175°C MWD/LWD)	Hephae Energy Technology
		c. Reservoir maintenance, flow control & completion, non-hydraulic stimulation; e.g., electronic reservoir stimulation (ERS)	Eden GeoPower, TerraFerno,
		d. Conventional rigs, drill bits (e.g., PDC) and reservoir consumables (casing, cement, mud) and associated services	Incumbent-dominated (Nabors, H&P, SLB, Halliburton, Baker Hughes); not venture-investable
C. Power Plant Innovations	15–30%	sCO ₂ turbines; modular/containerised plants; high-temp heat exchangers; ORC systems	Echogen, Critical Energy Systems, HRI, Hybrixcel, Gradient Geothermal

Source: PitchBook, company disclosures

The defining uncertainty for NGG picks & shovels investments is when, and on what terms, the large oilfield service firms (including Baker Hughes, SLB and Halliburton) will enter the market for geothermal enabling technologies. The risk profile of any given sub-segment hinges on whether the OFSEs ultimately act as buyers, acquiring proven NGG-focused startups at attractive valuations, or enter the market on their own terms. This is the same dynamic we have identified for NGG developers in their relationship with the oil & gas majors, and it is no less central to the picks & shovels thesis.

Where a geothermal technology is cross-applicable to mainstream oil & gas, OFSE incumbents (SLB, Halliburton, Baker Hughes, NOV, Weatherford) already possess transferable tooling and a clear commercial incentive to compete. NGG-focused startups in those segments are most exposed to

being out-competed rather than acquired on attractive terms. Where the technology only works above the temperature, rock-hardness or stimulation thresholds that defeat off-the-shelf O&G tools, or addresses problems specific to geothermal subsurface, the addressable market is narrower but the moat is structurally stronger and the path to a buyer-led exit clearer.

We have very little visibility into what any of the OFSEs may already be developing internally across these five sub-segments, and that opacity is itself part of the investment risk. The table below maps each picks & shovels technology against the markets where it has meaningful application. Sub-segments that tick across both geothermal and mainstream O&G are the ones where OFSEs are most likely to already be working on equivalent capability, and where the buyer-versus-pre-empter question matters most.

Exhibit 67

Picks & shovels segments — cross-applicability across NGG, geothermal and oil & gas (basis for OFSE entry-risk analysis)

Enabling Tech	NGG	All Geothermal	Only Super Hot O&G (>150°C BHT)	All O&G	Total market Size (\$B)
A. Geological Characterisation & Siting (AI-driven subsurface characterisation; reservoir modelling; subsurface imaging)					~\$0.5B addressable at full NGG scale (geothermal-specific subsurface software). NGG-built tools rely on training data and physics models for hot crystalline rock — the methodology overlaps with SLB / Halliburton / Bentley O&G subsurface software, but the data and rock physics don't transfer to sedimentary-basin O&G characterisation
B.a. Novel rock destruction (plasma, mm-wave, laser)					~\$5-7B addressable at full NGG scale (geothermal hard-rock drilling plus partial HPHT-O&G overlap). Hard crystalline rock destroys conventional PDC bits. General O&G drills sedimentary rock with conventional bits and has no commercial reason to switch.
B.b. High-temp downhole tools, electronics & measurement (>175°C MWD/LWD)					~\$0.5-1B addressable at full NGG scale. HPHT wells (Haynesville, deep Gulf of Mexico, ultra-deep Middle East gas) hit 150°C+ bottomhole temperatures that defeat standard MWD/LWD electronics — the same physics problem NGG faces, so the same high-temperature tool serves both markets. Below 175°C bottomhole, standard tools work fine, which is why the rest of O&G has no need for HT MWD.
B.c. Reservoir maintenance, flow control & non-hydraulic stimulation (e.g., ERS)					~\$10-20B addressable at full NGG scale (broadest cross-vertical TAM). Reservoir permeability is the binding NGG constraint, but the same toolset partially applies to conventional geothermal, HPHT-O&G and general O&G — alternatives to hydraulic fracturing could displace material share of the existing \$40-50B fracturing services market.
B.d. Conventional rigs, drill bits (PDC), casing, cement, mud and associated services					~\$60-100B+ globally today. The same rigs, OCTG, cement and mud services drill any well type — geothermal inherits decades of O&G drilling kit with minimal modification. Captured by OFSE incumbents and large independents (NOV, Weatherford, Patterson-UTI, Liberty); not venture-investable.
C. Power Plant Innovations (sCO ₂ turbines; modular/containerised plants; high-temp heat exchangers; ORC)					~\$5-10B addressable at full NGG scale (~\$15-25B for the full installed value chain). Surface power conversion is the value-capture step that turns thermal energy into electricity. Partial HPHT-O&G fit via ORC waste heat recovery on hotter waste streams (deep gas processing); general O&G waste streams are too low-grade for cost-effective ORC.

Notes: ● Broadly Applicable ● Partial / Niche Applicability ● Not Applicable

For Exhibit 67, “Super Hot O&G” denotes wells with bottomhole temperatures above ~150°C: the High-Pressure High-Temperature (HPHT) tier that includes the Haynesville shale (typically 150–200°C BHT), deep Gulf of Mexico HPHT developments (Tiber, Stones), North Sea HPHT plays (Elgin/Franklin) and ultra-deep Middle East gas. This represents roughly 5–10% of global O&G activity by well count and is the segment where O&G operators face the same temperature constraints NGG faces.

This framing matters: the picks-and-shovels thesis depends on the dual-use market being sized correctly. A modest crossover into high-temperature O&G (Haynesville, deep GoM HPHT, ultra-deep Middle East gas) provides a near-term revenue base for a startup while NGG capex scales, de-risking the investment without forcing the company to wait on geothermal deployment. The dual-use market must remain small, however. Where a sub-segment is broadly applicable across mainstream O&G, SLB, Halliburton and Baker Hughes possess transferable tooling and a clear commercial incentive to compete in-house, and the venture-backed startup is likely to be out-built rather than acquired. The optimal positioning is the ~5–10% of O&G activity that shares NGG’s physical constraints (high bottomhole temperatures, hard crystalline rock, non-hydraulic stimulation): sufficient to provide a commercial backstop, but too narrow to attract significant near-term OFSE investment.

Across the picks & shovels universe, most NGG sub-segments are genuinely geothermal-specific, which materially reduces OFSE entry risk relative to the shale-services analogy, but increases these technologies’ commercial risk. Only **conventional rigs and consumables** tick across all four columns, and that segment was never venture-investable in the first place. For all other picks and shovels categories, except downhole electronics, the physics, data or application is distinct enough from mainstream O&G that SLB, Halliburton

and Baker Hughes have neither transferable tooling nor a commercial reason to redirect R&D ahead of NGG demand at scale.

The clearest exception is **high-temperature downhole electronics and measurement (B.b)**. This is the only sub-segment with real dual-use applicability into HPHT O&G that overlaps directly with the OFSEs’ core MWD/LWD business. Halliburton already produces commercial MWD/LWD tools rated to 200°C and 30,000 psi, so the contestable ground is no longer “first past 175°C” but sustained reliability above 200°C and the path toward 250–300°C. The defensibility of a company in this segment like Hephæe Energy Technology depends on staying ahead on the reliability-at-temperature curve and locking in IP before the OFSEs decide HPHT volumes alone justify the next round of internal R&D spend. Paradoxically, this is also the most commercially attractive sub-segment in the picks & shovels universe, because the dual-use revenue lets a startup generate cash flow while NGG scales.

In two further sub-segments the relevant incumbents are not OFSEs. **Geological Characterisation & Siting** competes primarily with specialist subsurface software providers (Bentley/Seequent already offers a geothermal module in Leapfrog), and the moat is geothermal-specific training data and physics models rather than the AI methodology itself; companies pairing the tooling with proprietary land positions or operational data (Zanskar, Ignis Energy) will be more defensible than pure software plays.

Power Plant Innovations is dominated by power-equipment OEMs (Ormat, Mitsubishi/ Turboden, Fuji Electric, GE Vernova), where bankability track records and certification cycles make incumbent displacement a gradual process. The venture opportunity sits in modular factory-built form factors that incumbents have been slow to adopt.

Enabling Specialist Geothermal Technologies or “Picks & Shovels” – more lessons from shale gas

In shale, OFSEs captured most of the durable value because their existing rig fleets, frac spreads and downhole tooling could be redeployed into shale wells with minimal modification. The same equipment, services and crews that drilled conventional wells worked for unconventional ones too. In NGG, that direct redeployment is largely confined to conventional rigs and consumables (B.d), and partially to high-temperature downhole electronics (B.b). Across the remaining sub-segments (A, B.a, B.c and C), OFSE entry would require building a genuinely new technical capability rather than repurposing existing kit, which is unlikely until NGG capex scales materially. The most durable picks & shovels investments will combine dual-use applicability into adjacent deep-drilling markets (hot O&G, mining, ultra-deep gas) with defensibility at the temperature, hardness or chemistry threshold where incumbent tooling fails.

What the winning “Picks & Shovels” will look like

“Picks & Shovels” players that begin with a focused technology edge, such as a specialised high-temperature tool, advanced sensor, or niche drilling or stimulation service, and go onto successfully broaden into integrated, full-stack offerings stand to capture the most durable and scalable value in the NGG space. Halliburton, SLB, and Baker Hughes followed precisely this path in shale, evolving from core competencies into comprehensive, recurring-service platforms that dominated activity across basins. These companies can pursue self-integration to achieve scale, customer lock-in, and operational stickiness. If their intellectual property and early traction prove sufficiently defensible, acquisition by established incumbents active in geothermal can accelerate market reach and revenue growth while mitigating integration risks. The early winners need to have their long-term sights on transforming an initial niche advantage into high-margin, recurring

revenue across the ecosystem (“full stack”) rather than remaining exposed as narrow specialists vulnerable to commoditisation.

The edge has to be a capability incumbents cannot easily port over from their conventional toolkits. Adjacent niches like SHR O&G drilling and deep mining can extend the runway, but only because they share the same hard-rock, high-temperature problem set rather than because they offer generalist O&G revenue. We expect the most attractive opportunities to arise in segments where oil and gas incumbents are structurally underserved. While they dominate conventional drilling services, their equipment and workflows are optimised for sedimentary basins at moderate temperatures – most off-the-shelf downhole electronics and measurement fail above 175°C, well below the 300–400°C targets of some NGG wells. When tools fail at depth, rig downtime can exceed \$400,000 per day. The companies best positioned to capture value will share several characteristics:

- (1) diversified revenue streams across geothermal and adjacent frontier applications – SHR O&G drilling, deep hard-rock mining, and other ultra-high-temperature settings – rather than mainstream O&G services, smoothing out geothermal’s uneven project pipeline without competing head-on with incumbents on their home turf;
- (2) technology-agnostic adaptability across EGS, GGS, and closed-loop approaches to maximise addressable market;
- (3) a clear value proposition to developer customers built on quantifiable net benefits such as 20–50% LCOE reductions;
- (4) IP defensibility in hardware or software that incumbents cannot easily replicate, supported by low capital intensity that enables agile iteration and enhances M&A attractiveness;

- (5) strategic partnerships with operators or national labs that de-risk technology and provide field-test access; and
- (6) a credible path to integration — bundling multiple services to increase switching costs and margin. We suspect few startups listed below will tick all of these boxes at this stage of their development.

Five core technologies comprising NGG Picks & Shovels

Within drilling and reservoir creation, conventional services — rigs, casing, cement, mud, and associated surface and downhole equipment — represent roughly 65% of well costs and are excluded from this analysis. The segment is dominated by incumbents with multi-decade fleet and tooling investments (Nabors, Helmerich & Payne, SLB, Halliburton, Baker Hughes, NOV, Weatherford, Vallourec, Tenaris) that no venture-backed start-up can replicate, and our screen surfaced no early-stage companies of meaningful investment interest in this category. Geothermal will inherit this existing oilfield supply chain rather than disrupt it; the exposure for investors here is via the public equity of the incumbents — particularly H&P and Nabors, whose automated AC rig fleets are directly transferable from shale to EGS — not venture.

The venture opportunity is instead concentrated in five sub-segments where incumbent tools are fundamentally inadequate for next-generation conditions: AI-driven subsurface characterisation and siting, novel rock destruction, high-temperature downhole electronics and measurement, non-hydraulic stimulation and power plant innovation. Exhibits 69 through 73 list the most attractive technology sub-segments of “Picks & Shovels” with examples of start-up companies aligned with each.

The pattern is clear: the highest-scoring segments —geological characterisation, novel rock destruction, and downhole electronics and measurement (all 9/10) — share a common profile of urgent developer need

and structural disadvantages for incumbents. Power plant construction (5-6/10) scores lowest, reflecting deep incumbent entrenchment and limited paths for startup disruption.

Our research identified 41 geothermal Picks & Shovels related start-ups, of which 30 fit the Picks & Shovels definition used in this section. The remaining 11 sit outside the framework, primarily because they are ground-source heat pump or district-heating businesses rather than technologies that directly enable Next-Generation Geothermal deployment. Each in-scope company was scored on a 1–10 scale against ten criteria — NGG relevance, commercial maturity, capital scale, funding recency, investor quality, strategic partnerships, defensibility versus OFSE incumbents, NGG developer pull, cross-market applicability, and cost-saving benefit — producing a total out of 100.




Five companies cluster above the rest: GA Drilling (novel rock destruction), Eden GeoPower (stimulation and completion), Hephae Energy Technology (high-temperature downhole electronics), Echogen Power Systems (power plant construction and operations), and TerraFerno (stimulation and completion).

Specific “Picks & Shovels” Company Investment Opportunities

All five sit in high-scoring segments for the same reasons: focused IP where incumbents are structurally weak, credible partnerships that shorten the path to market, applicability across multiple geothermal approaches, and a realistic route to either integration or acquisition. Zanskar screens well on several criteria but is excluded here as it operates as a developer rather than a Picks & Shovels supplier, and is covered earlier in Strategy #1. The table below profiles each in turn (with fuller write-ups in the Appendix). All five are pre-revenue or early-revenue, reflecting the nascency of the NGG market, but each holds a defensible position in a segment where developer need is critical to its success.

Exhibit 68

Key “Picks & Shovels” players

Company	“Picks & Shovels” sub-sector	Description
 GA Drilling	Novel Rock Destruction	Slovak deep-tech company commercialising plasma-based drilling (PLASMABIT) that disintegrates rock contactlessly, enabling faster and cheaper access to deep geothermal resources beyond the reach of conventional rotary drill bits.
 Eden	Stimulation & Completion	US company offering proprietary Electrical Reservoir Stimulation (ERS) technology that creates permeability without hydraulic fracturing, reducing water use, induced seismicity risk, and environmental opposition.
 HEPHAЕ	Downhole Electronics & Measurement	US developer of extreme-environment downhole sensors and electronics currently rated to 210°C (targeting 300°C by 2030), providing the real-time subsurface data critical for characterising and managing Next-Generation Geothermal reservoirs.
 ECHOGEN	Power Plant Innovations	US developer of supercritical CO ₂ power cycle technology and Pumped Thermal Energy Storage, offering higher-efficiency thermal-to-electric conversion than conventional ORC at the elevated temperatures characteristic of Next-Generation Geothermal wells.
 TERRAFERNO	Stimulation & Completion	US developer of Autonomous Flow Control Devices and high-temperature downhole monitoring rated to 300–500°C, addressing heel dominance and flow short-circuiting in horizontal and multilateral geothermal wells to improve sweep efficiency and reservoir longevity.

Exhibits 69 through 73 below list the notable tech startups and their more established incumbent competitors across each segment of the geothermal value chain. Within drilling and reservoir creation, we break the segment into three sub-categories organised by the technical problem being solved: drilling speed, tool survivability or reservoir creation. Each segment is evaluated on a 1-10 investment attractiveness scale.

A) Geological Characterisation & Siting (Exploration, resource assessment, and reservoir modelling)

Our first NGG technology sector under the heading of “Picks & Shovels” is Geological Characterisation & Siting, which comprises exploration, resource assessment and reservoir modelling and accounts for less than 5% of total project costs but exerts an outsized influence on project risk. A mischaracterised resource can waste the other 95% of CapEx. The table below summarises key players and investment attractiveness.

Exhibit 69

Geological Characterisation & Siting

Venture / Tech-Stage Startups	Existing Market Leaders	Incumbent vs. Startup Dynamics	Investment attractiveness score & rationale
<p>Zanskar¹ — AI-native platform for predictive geothermal discovery and resource assessment. ~\$180M raised (\$115M Series C, Jan 2026). 20 GW pipeline. Partnerships with Ormat and Freeport-McMoRan.</p> <p>Ignis Energy — Proprietary geological screening engine integrating 49 geospatial data layers, 10 ML classifiers including U-Net deep-learning architecture, and computer vision applied to geological datasets. In 2025, screened over 775 million acres across the Western US and Indonesia, acquired 1,233 magnetotelluric stations, surveyed 48,387 acres across 11 leases, and produced four drill-ready assets.</p> <p>Adrok — Proprietary Atomic Dielectric Resonance (ADR) for rapid, non-invasive subsurface imaging.</p> <p>Terra AI — AI for subsurface characterisation, uncertainty modelling, and ultra-fast surrogate reservoir simulations.</p> <p>Other — New Mantle Technologies, TLS Geothermics</p>	<p>Seequent (Bentley Systems, NYSE: BSY) — Geological modelling software; Volsung module for geothermal reservoir simulation. Industry standard for conventional geothermal. Acquired 2021 for ~\$1.05B.</p> <p>Teverra — Specialist geothermal consultancy offering hydro-thermo-mechanical reservoir modelling, subsurface characterisation, and resource assessment services. Combines proprietary simulation tools with deep geothermal engineering expertise to support site evaluation, well targeting, and reservoir performance prediction ahead of drilling commitment.</p>	<p>AI startups will dominate predictive discovery, dramatically reducing exploration failure rates and increasing well success rates across both next-generation and traditional geothermal.</p> <p>O&G incumbents hold vast proprietary drilling and seismic data, but this data is optimised for sedimentary basins rather than the deep, fracture-dominated granite systems required for Next-Generation Geothermal.</p> <p>Startup AI models are superior at integrating diverse public/ open-source data (geochemistry, heat flow) for geothermal-specific targeting — a domain where incumbent seismic datasets offer limited advantage.</p>	<p>9/10 - This is the highest-ROI spend in the geothermal value chain. A small upfront investment (2–5% of CAPEX) can fundamentally de-risk an entire project by reducing exploration failure rates by an estimated 50–70%. The core value resides in non-physical, scalable IP — primarily AI/ ML models — making this the most VC-attractive segment. Incumbent geological software providers (Seequent/Bentley Systems) hold strong positions in conventional geothermal modelling, but their datasets are optimised for sedimentary basins and hydrocarbon systems rather than the deep, high-temperature, fracture-dominated granite systems that Next-Generation Geothermal targets. Startup AI models are proving superior at integrating diverse public and open-source data (geochemistry, heat flow, seismicity) for geothermal-specific targeting. Key risk: defensibility of AI moats if geological datasets become commoditised. Zanskar's integrated field operations (project-intensive, not just software) partially mitigates this.</p>

Source: PitchBook, company disclosures, Partners Capital analysis.

Note: 1) Zanskar has migrated from a pure-software model to direct ownership and operation of geothermal; it is therefore best characterised as a developer rather than as a pure picks-and-shovels play. More detail on Zanskar is provided in the section NGG Investment Strategy #1.

B) Drilling & Reservoir Creation

Drilling and reservoir creation is the dominant cost driver at 60–80% of total project CapEx — typically \$5–15M per well depending on depth and geology. Innovation here has the highest leverage on unit economics: a 25% reduction in drilling costs alone could unlock hundreds of GWs of new commercially viable capacity. We break this sector into three sub-segments, ordered from highest to lowest investment attractiveness.

Sub-segment 1 of 3: Novel Rock Destruction (~4% of well cost, but

highest leverage on total drilling economics)

Novel rock destruction targets the fundamental physics of how we break rock. Conventional PDC drill bits wear out 2–5x faster in abrasive granite than in sedimentary formations, forcing expensive round-trips to replace them. Each trip costs \$50–100K+ in rig time alone. Novel methods — plasma, millimetre-wave, hypersonic — promise a step-change in rate of penetration (ROP) that would collapse both the rig time charge (~32% of well cost) and contingency budget (~12%) — together roughly 44% of total well cost.

Exhibit 7o

Novel Rock Destruction

Venture / Tech-Stage Startups	Existing Market Leaders	Incumbent vs. Startup Dynamics	Investment attractiveness score & rationale
<p>Canopus Drilling Solutions — Directional Steel Shot Drilling (DSSD); hybrid steel shot erosion / PDC bit system.</p> <p>DeepPower — US/Utah-based drilling startup partnered with University of Oklahoma, claiming ~600% ROP improvement (XDrill™), targeting Super-Hot Rock.</p> <p>Foro Energy — High-power laser drilling for rock ablation.</p> <p>GA Drilling — Plasma-based drilling (PLASMABIT). Lab: 7.2 m/h in Super-Hot Rock; potential 17% initial cost reduction scaling to 90% long-term. \$67M raised. Partnerships: Nabors, Petrobras, NREL.</p> <p>Quaise Energy — Millimetre-wave (gyrotron) rock vaporisation. Targets 10–20 km depth. ~\$75M raised. 118m field demo July 2025.</p> <p>Other — Hades Mining, HyperSciences, I-Pulse (G-Pulse), Strada, TerraWave Energy, Zerda Labs</p>	<p>Baker Hughes — Vulcanix PDC bits for hard rock.</p> <p>BICO Drilling Tools — Custom high-temp bits, BHAs, stabilisers, reamers.</p> <p>Halliburton — Geothermal bit solutions.</p> <p>NOV — Phoenix drill bits; ReedHycalog PDC bits.</p> <p>SLB — Geothermal-specific bits and BHAs.</p>	<p>Highest disruption potential in the entire value chain. Current PDC bits wear out 2–5x faster in abrasive granite, forcing expensive trips. Novel drilling methods (plasma, mm-wave, hypersonic) promise a step-change in ROP that would collapse both rig time (32% of well cost) and contingency (12%) — together ~44% of well cost. Incumbents focus on incremental PDC improvements; startups own the IP on transformative approaches.</p>	<p>9/10 - The “moonshot” segment where venture capital can capture outsized returns. Faster ROP directly reduces the 32% rig time charge and 12% contingency budget. Innovations achieving a 25% cost reduction could unlock hundreds of GWs of new capacity. GA Drilling is the most advanced (Nabors partnership provides route to market). Quaise is the highest-conviction moonshot (MIT spinout, gyrotron physics). Hades offers dual-revenue optionality (geothermal + critical minerals). Key risk: translating lab performance to commercial field operations at depth. All pre-revenue, TRL 3–4.</p>

Source: PitchBook, company disclosures, Partners Capital analysis.

Sub-segment 2 of 3: High Temp Downhole Electronics & Measurement (~11% of well cost)

Downhole electronics and measurement are the “eyes and ears” of a drilling operation, providing the real-time data that tells operators where the bit is, what rock it is cutting through, and whether the well is on target. The sub-segment contains two distinct technology families. The first is electronic measurement — MWD (measurement while drilling) and LWD (logging while drilling) tools that sit in the bottom-hole assembly and transmit data to the surface as the well is being drilled. The second is distributed fibre-optic sensing, which runs a hair-thin silica fibre down the entire length of the wellbore and uses pulses of light, not electronics, to read temperature and vibration along its full length, both during drilling and over the well’s entire operating life.

Both families face the same fundamental constraint but solve it differently. Conventional electronic MWD and LWD tools fail above 175°C, precisely the temperatures at which Next-Generation Geothermal wells must operate, and a single tool failure at depth costs over \$400,000 per day in rig downtime. Fibre-optic sensing sidesteps

this electronic ceiling because the silica fibre itself tolerates well over 260°C and contains no downhole electronics to degrade. The trade-off is that fibre measures only temperature and acoustic signatures, not the full directional and formation-evaluation data that MWD and LWD provide — so the two technologies are complements rather than substitutes.

Fervo’s S-1 disclosures and patent filings show how strategically important fibre-optic sensing has become to NGG developers. A Thunder Said Energy review of twelve Fervo patent families (April 2026) finds that fibre-optic sensing features in approximately 50% of Fervo’s patent disclosures, covering distributed acoustic sensing, distributed temperature sensing and microseismic monitoring. Until electronic tools clear the 175°C ceiling, fibre-optic is the only viable measurement technology at NGG operating temperatures for the parameters it can capture — putting EGS developers without comparable in-house fibre-optic IP at a structural disadvantage, and creating a clear opening for specialised geothermal technology companies (e.g. Hephæ Energy Technology, in the table below) that can lift the electronic-survivability ceiling above 175°C.

Exhibit 71

High Temp Downhole Electronics & Measurement

Venture / Tech-Stage Startups	Existing Market Leaders	Incumbent vs. Startup Dynamics	Investment attractiveness score & rationale
<p>Hephae Energy Technology — High-temperature MWD/LWD tools and PandoraX RSS surpassing the 175°C barrier where all incumbent tools fail. \$6.35M raised (Nov 2024).</p> <p>TerraFerno — Autonomous Flow Control Devices (FCDs) purpose-built for geothermal, addressing heel dominance and flow short-circuiting in horizontal/multilateral wells; high-temperature downhole monitoring rated to 300–500°C.</p>	<p>Baker Hughes — i-Trak automation for directional control.</p> <p>Halliburton — Geo-Pilot RSS; BHA components.</p> <p>SLB — PowerDrive RSS; HDS-1 LWD tools; geothermal directional services.</p> <p>Weatherford — Magnus directional tools; Heatwave MWD.</p>	<p>Incumbents are competitive at conventional temperatures, but their tools degrade above 175°C. This is a horizontal market: every developer (Fervo, Sage, Mazama, Eavor) needs high-temp electronics regardless of drilling method. The venture opportunity lies in SiC/GaN-based electronics that surpass the temperature barrier.</p>	<p>9/10 - High-margin, licensable IP play with horizontal applicability across all geothermal developers. Hephae is the only pure-play startup addressing this gap — creating potential first-mover advantage. Small capital base (\$6.35M) means early investors could capture significant upside. Key risk: incumbents could accelerate internal R&D if the market grows, but geothermal remains a small fraction of their revenue, reducing incentive to prioritise.</p>

Source: PitchBook, company disclosures, Partners Capital analysis.

Sub-segment 3 of 3: Stimulation & Completion (Embedded in completion costs, typically 5--10% of total well CapEx)

Stimulation is the process of creating or enhancing permeability in hot rock so that fluid can circulate and extract heat.

Conventional hydraulic fracturing works but carries two risks that have historically derailed entire geothermal programmes: induced seismicity (Basel 2006, Pohang 2017) and high water consumption. Non-hydraulic alternatives directly address both — at an estimated 80% cost reduction per well (\$1M vs. \$5M for conventional frac).

Exhibit 72

Stimulation & Completion

Venture / Tech-Stage Startups	Existing Market Leaders	Incumbent vs. Startup Dynamics	Investment attractiveness score & rationale
<p>Eden GeoPower — Electrical reservoir stimulation (non-hydraulic). Uses electrical pulses to enhance permeability without water or proppants. \$12M raised.</p> <p>Other — Metharc</p>	<p>Baker Hughes — Stimulation and completion services.</p> <p>Halliburton — Frac services, completion systems, perforation.</p> <p>SLB — Hydraulic fracturing services; integrated stimulation and completion.</p>	<p>Incumbents dominate conventional hydraulic frac but face regulatory headwinds. Startups targeting non-hydraulic approaches own the IP in an area where incumbents have limited incentive to cannibalise their multi-billion-dollar frac businesses.</p>	<p>7/10 - Addresses induced seismicity and water-use concerns — the #1 permitting barrier to EGS scaling. Basel (2006) and Pohang (2017) halted entire programmes. Eden GeoPower is the standout: if electrical stimulation works at scale, it unlocks geothermal in regions where hydraulic frac is politically unviable (EU, Japan, Korea, urban US). Key risk: if hydraulic frac with better monitoring proves sufficient for regulators, urgency for alternatives diminishes.</p>

Source: PitchBook, company disclosures, Partners Capital analysis.

C) Power Plant Innovations

Turning from the upstream drilling supply chain to the final stage of a geothermal project, power plant construction and operations represent 15–30% of total project costs — typically \$1–3M per MW

for binary ORC plants, covering turbines, heat exchangers, cooling systems, and site construction. This is a segment where incumbents, led by Ormat, are firmly entrenched through bankable track records and long certification cycles.

Exhibit 73

Power Plant Innovations

Venture / Tech-Stage Startups	Existing Market Leaders	Incumbent vs. Startup Dynamics	Investment attractiveness score & rationale
<p>Critical Energy Systems — Factory-made modular power plants in shipping containers; plug into geothermal heat and generate electricity in weeks.</p> <p>Echogen Power Systems — Supercritical CO₂ power cycles for high-efficiency conversion; Pumped Thermal Energy Storage (PTES) for long-duration storage. Founded 2007.</p> <p>Gradient Geothermal — modular ORC packaging company whose primary near-term market is oilfield waste heat, with NGG as an adjacent application.</p> <p>Heat Recovery Innovations (HRI) — Compact high-temperature recuperators/heat exchangers capturing waste heat up to 2000°F.</p> <p>Other — Entent, Hybrixcel</p>	<p>Fuji Electric — Turbine manufacturer. ~\$20B market cap.</p> <p>OLI Systems — Geochemical simulation platform predicting mineral scaling and corrosion in geothermal production systems.</p> <p>Ormat Technologies — Binary/flash power plants. Global market leader. ~\$4B market cap.</p> <p>Turboden (Mitsubishi Heavy Industries subsidiary) — ORC systems.</p>	<p>Incumbents like Ormat will continue to dominate through brand loyalty and bankable track records in binary/flash plant construction. Scale favours established players with certification history and customer relationships. While technical innovations (advanced ORC, sCO₂ turbines, modular containerised plants) offer high potential margins, the market is characterised by high capital barriers, slow certification cycles, and strong incumbent brand loyalty, making disruption difficult and gradual. Startups excel in niche efficiency (modular plants, waste heat recovery, storage integration) rather than head-to-head with Ormat on large-scale binary.</p>	<p>6/10 - sCO₂ turbines are the most interesting sub-theme — both Echogen and Sage Geosystems are developing these, validating the thesis. sCO₂ is a better secondary fluid for high-pressure geothermal systems (aligning with Sage's approach) and offers higher theoretical efficiency than ORC at elevated temperatures. Modular/containerised power plants (Critical Energy Systems) address a real bottleneck: conventional power plant construction is 15–30% of cost and 12–24 months of schedule. If a factory-built unit can cut this to weeks, it dramatically improves project IRRs. However, this is a slow-burn opportunity. ORC is bankable and proven; lenders and offtakers require track records. Echogen has been developing sCO₂ cycles since 2007 without achieving market dominance, illustrating the difficulty of displacing incumbent technology in power conversion.</p>

Source: PitchBook, company disclosures, Partners Capital analysis.

Conclusion

Our aim at True North is to invest, and encourage others to invest, in the most powerful decarbonising new technologies. Geothermal is among the most compelling of these; a technology that can deliver clean, firm, baseload power anywhere with sufficient subsurface heat, at a cost trajectory that is converging on competitiveness with natural gas. The economics are moving in the right direction, the policy tailwinds are real, and the parallels to shale gas suggest that once the technology crosses the threshold from experimental to industrial, capital will follow rapidly. But we should be clear-eyed about where we are today: this is still a sector where very little commercial-scale production has been achieved and where the pace of development has consistently surprised to the downside. Drilling for heat is always going to be less financially attractive than drilling for natural gas, in large part, because of the timing of cash flows. Unless SHR breakthroughs materialise, NGG may remain a 10–15% IRR business for the foreseeable future, which is respectable but not the venture-style outcome to which many early investors are underwriting.

To structure a portfolio of investment exposure to geothermal that captures value without bearing disproportionate pioneer risk, we believe a portfolio approach across the three strategies outlined above will

deliver the best risk-adjusted returns to venture and private equity investors. Such a diversified approach would entail backing the strongest developers early enough to benefit from the valuation step-up when project finance arrives, owning “Picks & Shovels” technology providers who win regardless of which developer or technology prevails, and capturing de-risking premiums through first-10% strategies which may require some proactive efforts with firms focused on geologic characterisation and siting capabilities.

For the investment industry more broadly — and for coalitions like All Aboard that aim to shape outcomes rather than simply observe them — the opportunity is to work collaboratively with the new entrants to accelerate the development of this sector: investing to de-risk the critical first projects, helping developers access lower-cost capital sooner, and shaping a diversified group of winners across each investment cohort. Geothermal’s success is inextricably tied to the capital that commits to it in the belief that the costs can come down faster than the market expects and, in doing so, creates the conditions for the strategic investments to be made by the oil majors to accelerate the investment pace and scale of the next generation geothermal industry.

Appendix

Five Specific “Picks & Shovels” Company Investment Opportunities

Exhibit 74

GA Drilling — Drilling Speed (Segment 2a)



Overview	
Technology & Edge	Plasma-based rock destruction (PLASMABIT / Anchorbit®), lab-validated at 7.2 m/h in super-hot granite, targeting 17% near-term and 90% long-term drilling cost reduction. The Anchorbit® integrates into conventional rigs as a bolt-on BHA upgrade — no new equipment, no operational overhaul. Operators gain hard-rock performance while leveraging existing fleets and workflows, minimising CapEx and training requirements. This contrasts sharply with alternatives like Quaise’s gyrotron system, which demands custom equipment and wholesale operational change. It’s the primary reason we view GA Drilling as the most credible near-term route to market among novel rock destruction companies.
Headquarters	Bratislava, Slovakia
Capital Raised	~\$110M (\$82.7M Series C, March 2026; \$15M Series B, 2024; \$8M Series A, 2022; €4.2M earlier rounds)
Key Investors	Nabors Industries (strategic), TomEnterprise (Series C lead), Underground Ventures, Neulogy Ventures, Lead Ventures, Berlin Technologie Holding
Key Partnerships	Nabors Industries (route to market via global rig fleet), Petrobras (technical cooperation), NREL (geothermal acceleration)
Why It Fits Our Criteria	
Diversified Revenue	Applicable to O&G deep wells, mining, and geothermal — not dependent on any single end-market.
Quantifiable Value	Drilling is 60–80% of NGG capex and bit performance dictates ROP; a step-change in ROP collapses both the 32% rig-time charge and 12% contingency budget.
IP Defensibility	Plasma physics is a fundamentally different approach to rock destruction that incumbents (NOV, Baker Hughes) cannot replicate through incremental PDC bit improvements. Unlike millimetre-wave or waterjet approaches, plasma drilling has been demonstrated in a hybrid configuration compatible with existing rig infrastructure — the technology iterates on proven equipment rather than requiring a new drilling paradigm.
Strategic Partnerships	Nabors partnership provides direct route to market via an existing global rig fleet, plus Petrobras and NREL collaborations.
Path to Integration	Drilling speed technology naturally extends into adjacent BHA and completion services. The “bolt-on” architecture means any rig operator can adopt the technology incrementally, creating a low-friction adoption curve and reducing commercial risk relative to competitors requiring ground-up system changes.
Key Risk	
Translating lab ROP to commercial depth and sustained field operations. TRL 3–4; all novel rock-destruction companies are pre-revenue. The competitive landscape is also intensifying: percussive drilling (Strada, HydroVolve), waterjet (Orchyd project) are all advancing as alternative or complementary approaches to hard-rock drilling.	

Source: Company disclosures, PitchBook

Overview	
Technology & Edge	Electrical Reservoir Stimulation (ERS): pulsed electrical energy creates dense, self-propped fracture networks without water, proppants, or induced seismicity. Lab-validated 1,000% permeability increase in hard rock; 130% oil production uplift in PDO field pilot (Oman). ~\$1M/well vs ~\$5M for hydraulic fracturing.
Headquarters	Boston, MA (MIT spinout, founded 2017)
Capital Raised	~\$14.6M equity + ~\$10M non-dilutive grants (NSF, DOE, ARPA-E). Raising \$30M Series A (targeting Q3 2026).
Key Investors	TechEnergy Ventures (seed co-lead), Helmerich & Payne (seed co-lead, NYSE: HP), Grantham Foundation, Anglo American Capital, Good Growth Capital, MassVentures, Portfolia Green & Sustainability Fund
Key Partnerships	Mazama Energy (330°C geothermal demonstration), ARPA-E, NSF, Utah FORGE. Pilot roadmap: Utah FORGE (225°C, 2027) > Newberry (330°C, 2028) > Salton Sea (>375°C, 2029).
Why It Fits Our Criteria	
Diversified Revenue	Four end-markets — O&G restimulation (~\$800B TAM), geothermal (~\$50B TAM), mining, and geologic hydrogen — providing near-term O&G cash flow (\$1.3M contract signed in 2026, \$10M restimulation contract pipeline targeted for 2027) while geothermal scales. Company projects \$500M revenue by 2035 across the four markets.
Quantifiable Value	80% cost reduction per well vs hydraulic fracturing (\$1M vs \$5M), directly lowering LCOE. Eliminates >10M gallons of water and ~5M lbs of proppant per well.
IP Defensibility	Mazama Energy partnership for the 330°C demonstration is the keystone — it pairs ERS with one of the most advanced Super-Hot Rock developers, and the staged Utah FORGE > Newberry > Salton Sea pathway provides progressive temperature de-risking through 2029.
Strategic Partnerships	Mazama Energy partnership for 330°C geothermal demonstration; pilot roadmap through Utah FORGE to Newberry to Salton Sea provides a staged de-risking pathway.
Path to Integration	Dual revenue model: stimulation services at 20–30% margin (~\$5M per geothermal job) + production royalties (e.g., \$0.10/kWh on 25-year PPAs) creates recurring income and customer lock-in. Cross-applicability across O&G, geothermal, mining, and hydrogen creates a manufacturing-and-services platform rather than a single-vertical play.
Key Risk	
ERS validated at boulder scale and 60 m depth (Edgar Mine, TRL 6) but not yet at commercial geothermal depths and temperatures — the Utah FORGE / Newberry / Salton Sea sequence is the de-risking path, and slippage at any step pushes the geothermal revenue ramp out. If improved microseismic monitoring makes hydraulic fracturing acceptable to regulators, urgency for non-hydraulic alternatives diminishes; however, multiple European countries have either banned or imposed moratoria on hydraulic fracturing, creating a regulatory floor of demand for non-hydraulic alternatives regardless of monitoring improvements.	

Source: Company disclosures, PitchBook

Overview	
Technology & Edge	High-temperature MWD/LWD tools (Pandora 210) rated above 210°C using SiC/GaN electronics — surpassing the 175°C ceiling at which all incumbent directional tools fail. Hephae's core innovation goes beyond component selection: the company has fundamentally redesigned downhole electronics and measurement architecture, replacing traditional long, thin rectangular circuit boards (effective for shock/vibration but poor at heat dissipation) with circular boards stacked in a disc configuration. This allows heat to transfer efficiently from the centre of the board to the outer casing. Their patented heat management system — including ceramic casings for electronics and a proprietary mounting design that conducts heat along an aluminium stack toward the drill bit — reduces component self-heating from up to 40°C above ambient to less than 5°C. The company holds seven patent applications related to thermal transfer. Roadmap to Pandora 300 and ultra-high-temperature RSS by 2027.
Headquarters	Houston, TX (with teams in Spain and UK)
Capital Raised	~\$6.35M (seed round, November 2024)
Key Investors	Underground Ventures (lead), Future Ventures, Grantham Foundation, Exascale Fund, Nabors Industries
Key Partnerships	Nabors Industries (strategic investor). Letters of support from Fervo Energy and Mazama Energy. Fervo currently relies on standard systems below 200°C but anticipates reaching 250°C and views Hephae's solutions as transformative. Tools are plug-and-play across various drilling methods, including compatibility with GA Drilling's plasma systems and Quaise's millimetre-wave approach.
Why It Fits Our Criteria	
Modality-Agnostic	Every NGG developer (EGS, ACL Advanced Closed-Loop) requires directional drilling tools that survive downhole temperatures; this is a horizontal market regardless of which drilling or stimulation method prevails.
Quantifiable Value	When downhole tools fail at depth, rig downtime exceeds \$400,000/day — a reliable high-temp MWD/LWD platform directly eliminates this cost and enables the speed innovations in segment 2a to be deployed effectively. Pandora 210 slashes drilling costs by approximately 40% in the 150–300°C range common to EGS by preventing rig trips and reducing staging time.
IP Defensibility	The industry has stalled at ~175°C capabilities for the past 30 years despite earlier confidence in advancing 25°C per decade. Major incumbents have spent tens of millions unsuccessfully. Baker Hughes, Halliburton, and SLB have all invested significant R&D in similar tools but rely on traditional ceramic casings with long, thin configurations — none have come close to the temperatures Hephae achieves (210°C for 200+ continuous hours under high heat, vibration, and shock). Weatherford and Halliburton have managed tools approaching 200°C but only for brief periods and at prohibitive expense. Hephae believes it holds a five-year head start.
Path to Integration	A proven high-temp electronics platform naturally extends into rotary steerable systems, downhole sensors, and data analytics — building switching costs over time. Licensable IP model with minimal physical infrastructure makes the company highly M&A-attractive to SLB or Halliburton. Hephae's ultra-high temperature technology is designed for the full life cycle of geothermal — from drilling and completions to operations and maintenance — creating multiple revenue entry points beyond the initial MWD/RSS product.
Key Risk	
Single-product risk at this stage. Incumbents could accelerate internal high-temp R&D if the geothermal market scales enough to justify the investment, though geothermal remains a small fraction of their revenue, reducing this incentive. However, the strength of incumbent interest (enquiries from all majors) also means acquisition risk is real — Hephae may be bought before it can capture the full value of its platform independently.	

Source: Company disclosures, PitchBook

Overview	
Technology & Edge	Supercritical CO ₂ (sCO ₂) power cycles and Pumped Thermal Energy Storage (PTES): turboexpander cycle delivers higher thermal-to-electric efficiency than conventional ORC at NGG-relevant temperatures (>200°C), with turbine hardware ~1/100th the volume of equivalent steam turbines. 30–35% lower installed cost and ~50% smaller footprint than steam. Compatible with Super-Hot Rock (300–400°C) where ORC degrades.
Headquarters	Akron, OH (founded 2007 as Rexorce Thermionics, spun out of Cognitek)
Capital Raised	\$59M total (PitchBook, Jan 2023): \$25M corporate strategic from Dresser-Rand, \$22M DoE grants, \$12M VC equity.
Key Investors	Dresser-Rand Group (now Siemens Energy), Jumpstart Ventures, mTerra Ventures, Plug and Play Tech Center, Bally Energy, Aberne, U.S. Department of Energy
Key Partnerships	Westinghouse Electric (commercial agreement Nov 2024): first deployment is a 50 MW / 1.2 GWh PTES system in Alaska with Golden Valley Electric Association — one of the largest of its kind globally. Westinghouse-VVB MOU signed July 2025 for Europe's first grid-scale PTES in Slovakia, operational 2030. Lawrence Berkeley National Laboratory (LBNL) and UT Austin partnership for direct geothermal applications via the GCS/GHE programme.
Why It Fits Our Criteria	
Diversified revenue	Four end-markets — Pumped thermal energy storage (PTES) (the active commercial channel via Westinghouse), waste-heat-to-power (industrial sources at 450–1,200°F), high-temperature industrial heat pumps (programme launched August 2024), and direct geothermal generation via the LBNL GCS/GHE programme. PTES and waste-heat pipelines provide near-term revenue while NGG geothermal scales.
Quantifiable value	30–35% lower installed cost and ~50% smaller footprint than steam at equivalent power output. Higher theoretical conversion efficiency than ORC at NGG operating temperatures, with the gap widening above 300°C — directly relevant to SHR developer LCOE (Sage Geosystems' sCO ₂ approach validates the thesis).
IP Moat	49 patent families and 222 total patent documents, 125 active grants. Top-cited patents on hybrid power generation with integral thermal waste-heat recovery (213 forward citations) and hybrid power generation / energy storage (187 citations)
Business model optionality	Multi-product sCO ₂ platform creates recurring service and parts revenue across PTES, waste-heat and (prospectively) geothermal installed bases — a manufacturing-and-services platform rather than a single-vertical play. Strategic-investor dominated cap table makes acquisition by a power-equipment OEM plausible.
Path to Integration	Dual revenue model: stimulation services at 20–30% margin (~\$5M per geothermal job) + production royalties (e.g., \$0.10/kWh on 25-year PPAs) creates recurring income and customer lock-in. Cross-applicability across O&G, geothermal, mining, and hydrogen creates a manufacturing-and-services platform rather than a single-vertical play.
Key Risk	
Echogen is relatively weak on NGG commercial momentum: 18 years of sCO ₂ development without achieving market dominance. The headline Westinghouse deployment is PTES, not geothermal generation — so the geothermal revenue ramp depends on either NGG developers adopting Echogen turbomachinery at commercial scale, or the LBNL/UT Austin GCS/GHE programme progressing from research to deployment. Both pathways are multi-year and not yet underway.	

Source: Company disclosures, PitchBook



Overview	
Technology & Edge	Patent-pending well-integrity and flow-control hardware purpose-built for Super-Hot Rock geothermal. Core products: (i) cemented liner hanger packers rated 500°C / 15,000 psi —SHR-aligned operating envelope; (ii) autonomous Flow Control Devices solving the "heel-dominance and short-circuiting" reservoir-management problem in horizontal NGG wells; (iii) downhole monitoring instrumentation rated 300–500°C; (iv) float equipment. Bench-scale validation only — no commercial pilots disclosed. Targeting the well-design and completion segment.
Headquarters	Calgary, Canada (founded 2019). 6 FTEs. Foresight 50 (2025) and Earth Tech 2050 cohort recognition.
Capital Raised / investors	Undisclosed Later Stage VC round closed July 2025 (Nomadic Venture Partners as new investor). Earlier participation in Scale Up Canada / Calgary50 accelerator programme (January 2025 — non-dilutive). Total capital raised not publicly disclosed; estimated sub-\$5M based on round visibility and headcount. Nomadic Venture Partners (lead, July 2025); Scale Up Canada / Calgary50 (accelerator).
Key Partnerships	Pre-commercial. No named developer partnerships disclosed publicly.
Why It Fits Our Criteria	
High-ROI Segment	TerraFerno targets the well-design and integrity segment, the thinnest sub-segment in next-generation geothermal — approximately six companies sector-wide versus twenty-six in drilling. The supply of investable names addressing well integrity at SHR conditions is genuinely scarce. Every developer pursuing the >374°C operating envelope (Mazama at Newberry, Eden at Salton Sea, Quaise at Project Obsidian) will need hardware rated above the current OFSE ceiling. This is exactly the kind of HT niche where OFSE incumbents and O&G majors are unlikely to enter — the absolute number of super-hot wells is too small to justify Vallourec / NOV / Schlumberger Completions investing internal R&D against it.
Spec focus (SHR)	500°C / 15,000 psi cemented liner hanger packers plus 300–500°C downhole monitoring is the most aggressive SHR-aligned operating envelope in the cohort, materially ahead of incumbent HT well-completion hardware (typically rated 175–260°C). If validated, the spec unlocks well-integrity solutions for the super-hot operating range that the industry cannot reach with off-the-shelf OFSE hardware today. The value proposition is strategically important to customers: without HT-rated well integrity, SHR wells cannot be completed at all.
Modality-Agnostic	Well-integrity hardware applies across every NGG developer pursuing high-temperature operations, regardless of drilling method or reservoir technology — EGS, SHR, ACL, geopressured. Mazama (advanced conventional drilling at SHR temps), Quaise (mm-wave drilling at SHR temps), Eden (electrical reservoir stimulation), Fervo (horizontal EGS) all need HT well integrity once temperatures exceed the OFSE ceiling. The addressable market widens with every developer that crosses the 300°C boundary.
IP Defensibility	Patent-pending IP on both the autonomous Flow Control Device heel-dominance solver and the 500°C / 15,000 psi cemented liner hanger packer. Defensibility today is more a function of the structural thinness of the segment than of a deep IP fence — the six-FTE team is limited in IP-defence capacity. The incumbent-restraint dynamic is the same one that protects Hephæe in HT MWD: OFSEs are absent because the SHR sub-segment is too narrow to attract internal R&D, leaving the niche to focused specialists.
Key Risk	
TRL is early — bench-scale only and the 500°C / 15,000 psi specification remains a paper claim, not yet validated in field conditions. Six-FTE team is structurally undersized to scale execution against the stated specification; substantial Series A capital required to bridge from current bench-scale work to field validation and serial manufacturing. Demand-side dependency is also material: the value proposition rests on the SHR project pipeline (Mazama, Quaise, Eden's Salton Sea, future entrants) materialising on schedule. If SHR developer progress stalls, TerraFerno's addressable market arrives later. Re-engagement is conditional on (i) a strategic joining the cap table and / or (ii) a named developer pilot being signed.	

Source: Company disclosures, PitchBook

True North Institute

The True North Institute is a research-driven investment platform focused on identifying the technologies, sectors and macroeconomic shifts most likely to shape the future of the global economy and energy transition. Combining deep fundamental analysis with a strategic institutional-investor lens, TNI conducts rigorous research into areas such as geothermal energy, long-duration storage, hydrogen, carbon markets, grid infrastructure and broader institutional portfolio strategy. The firm's work is grounded in the belief that the world's largest investment opportunities emerge where technological change, policy, capital flows and long-term economic fundamentals intersect — and that objective, evidence-based analysis is essential to identifying those opportunities early.

TNI also operates as an active investment

platform, deploying Miranda family capital into companies and projects accelerating the global energy transition. In 2025, TNI co-founded the All Aboard Coalition and All Aboard Fund alongside Chris Anderson's Exascale, bringing together many of the world's leading climate-tech venture and growth investors to help breakthrough energy technologies scale beyond the commercial "valley of death." Through both its research and investment activities, TNI seeks to mobilise institutional capital toward technologies capable of delivering long-term economic value while materially decarbonising the real economy.

TNI operates from its office in London and is staffed with a small team including Stan Miranda, Jack Haynes, Tristan Varakuta and Rosanna Quayle.



Stan Miranda
Founder and CEO



Jack Haynes
Partner, Head of Investments



Tristan Varakuta
Investment Associate



Rosanna Quayle
Chief of Staff



Above: Aerial picture of geysers geothermal plant



Michelin House
81 Fulham Road
London SW3 6RD
United Kingdom

www.truenorthinstitute.com