

NEXT-GENERATION GEOTHERMAL CASE STUDY SERIES

Unlocking Scalable, Investable Geothermal Energy

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Acknowledgments

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Foreword: Building the Case for Next-Generation Geothermal

Geothermal energy stands at an inflection point. For decades, it has been a proven and reliable source of power that is also constrained by geography, available primarily where nature has done the hard work of concentrating heat, permeability, and fluid in accessible formations. That is changing rapidly.

Advances in drilling technology, reservoir engineering, and new system architectures are transforming geothermal from a niche resource into a globally deployable energy solution. From the high desert of Utah, where the FORGE field laboratory is rewriting what is possible in engineered geothermal systems, to the mountains of Iceland, the volcanic fields of Indonesia, and the deep sedimentary basins of Central Europe, next-generation geothermal is proving that firm, dispatchable power can be developed across a much wider range of geographies.

The GeoFuture Initiative was established within the Clean Energy Ministerial (CEM) precisely to accelerate the deployment of next-generation geothermal technologies. CEM's mission is to help countries evaluate, finance, and deploy next-generation geothermal technologies by sharing knowledge, reducing barriers, and connecting decision-makers with the information they need to act.

This Case Study Series is a core output of that mission. It brings together evidence from 13 global geothermal projects spanning the full spectrum of technology pathways, from enhanced geothermal system (EGS) research laboratories to mature hydrothermal fields, from superhot rock frontiers to closed-loop commercial pilots. Each case study is structured to answer the questions that matter most to energy ministers, planners, and investors: What were the drivers and constraints? What technology was chosen and why? What did it cost, and what risk was involved? What worked, and what did not? And critically, what can be replicated and/or scaled up?

We invite CEM member countries and partner organizations to engage with these findings, continue to build on these case studies, and work with the GeoFuture Initiative to accelerate geothermal deployment in their own contexts. ■



Jean-François Gagné

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List of Acronyms

AGS	advanced geothermal system	ES	Électricité de Strasbourg
CEM	Clean Energy Ministerial	FORGE	Frontier Observatory for Research in Geothermal Energy
CFE	Comisión Federal de Electricidad (Mexico)	IEA	International Energy Agency
CHP	combined heat and power	KAUST	King Abdullah University of Science and Technology
CONICET	Consejo Nacional de Investigaciones Científicas y Técnicas	LCOE	levelized cost of electricity
DAS	distributed acoustic sensing	MWe	Megawatt-electric
DOE	U.S. Department of Energy	NLR	National Laboratory of the Rockies
DTS	distributed temperature sensing	R&D	research and development
EDC	Energy Development Corporation (Philippines)	SHR	superhot rock
EGS	enhanced geothermal system		

Executive Summary

Countries around the world are contending with two interconnected challenges: meeting electricity demand that is rising faster than at any point in decades—driven by industrial growth, electrification, and new large loads such as data centers—while simultaneously strengthening energy security and reliability. Firm, dispatchable, domestically produced power can play an important role in addressing both challenges, and advances in next-generation geothermal technologies are expanding the potential for geothermal to provide these attributes across a much broader range of geographies. The projects examined in this series demonstrate that key barriers—including cost, subsurface risk, financing, and enabling policy and regulatory frameworks—are increasingly being addressed through real-world projects, providing practical lessons for further deployment and scale.

Historically, geothermal deployment has been constrained by the availability of naturally occurring hydrothermal resources, limiting commercial development to a small number of geographies. However, advances in drilling, reservoir engineering, and system architecture are rapidly expanding geothermal's geographic applicability and economic potential. Analysis from the International Energy Agency (2024) indicates that next-generation geothermal could unlock hundreds of gigawatts of global electric generating capacity, with market potential exceeding 800 GWe by 2050.

Next-generation geothermal technologies, including enhanced geothermal systems (EGS), closed loop geothermal systems, and superhot rock, represent one of the most underdeveloped opportunities in the global energy sector. Geothermal delivers continuous, dispatchable power with capacity factors of 60%–90% (IEA, 2024).

This Case Study Series, developed under the GeoFuture Initiative of the Clean Energy Ministerial, presents evidence from 13 geothermal projects spanning four technology types and 11 countries. Together, they provide a structured framework for decision makers seeking to evaluate, finance, and deploy next-generation geothermal in their own national or geographic contexts.

Three themes emerge consistently across these case studies. **First, next-generation geothermal is no longer theoretical:** EGS, closed-loop, and superhot rock systems are being demonstrated today, benefiting from

valuable technical learning curves, and the technologies themselves are not the primary constraint on further deployment. **Second, the barriers that remain (e.g., subsurface uncertainty, access to capital, workforce capacity, and permitting) are addressable** through approaches already proven in these cases, including early subsurface characterization, public-private risk-sharing, and technology transfer from the oil and gas sector. **Third, the barriers, and the tools to address them, are not evenly distributed:** Countries and companies with less mature markets or limited access to capital, technical expertise, or drilling infrastructure face a steeper path, which is where international collaboration and technical assistance can play an important role.

Key Statistics

30%–60%

Percent of
project costs
attributed to
drilling

60%–90%

Average
capacity factor
for geothermal
power

800 GWe

Estimated
global market
potential of
next-generation
geothermal by
2050

Across all case studies, six consistent findings emerge:

1. **Subsurface uncertainty is the major determinant of project risk.** Projects that invest in early subsurface characterization, geophysical surveys, exploratory drilling, and downhole monitoring can reduce uncertainty and strengthen the information available to prospective investors and lenders.
2. **Drilling is a dominant cost driver,** typically accounting for 30%–60% of total project costs, and improvements in drilling speed and efficiency represent an important opportunity for cost reduction across geothermal technology types. These gains are driven both by technological advances (e.g., horizontal drilling, multi-well pad design, and high-temperature materials) and by an increasingly transferable experienced workforce, with many of the underlying innovations drawn from the oil and gas sector. Projects such as Utah FORGE and Fervo Energy's Cape Station demonstrate substantial improvements in drilling performance as experience accumulates; however, the magnitude of these gains varies by project, metric, and baseline, and access to these improvements remains uneven across countries and technologies.

3. **Technology transfer from oil and gas has materially accelerated drilling and well completion performance.** Cross-sector innovation, particularly in horizontal drilling, multi-well pad design, and hydraulic fracturing techniques, has transformed the economics of EGS development to date, and similar cross-sector technology transfer is beginning to extend to superhot rock, closed-loop and hybrid systems as well.
4. **Public-private risk-sharing can be essential to unlock private capital.** Early-stage public investment in exploration, data acquisition, and pilot demonstration substantially reduces the risk premium demanded by private investors.
5. **Policies and regulations that specifically address geothermal can foster successful deployment.** Clear regulatory frameworks, streamlined permitting, and defined power purchase mechanisms are consistently associated with successful project outcomes.
6. **Next-generation geothermal has demonstrated potential across a broad range of markets and geographies.** The case studies span mature and emerging economies and volcanic and non-volcanic settings, illustrating viable geothermal pathways across a range of geological and market conditions. The suitability of any specific technology, however, remains dependent on site-specific resource characteristics, infrastructure, market conditions, and project objectives.

Case Studies at a Glance

GROUP	CASE STUDY	PROJECT, COUNTRY	FEATURES	OPERATOR	KEY LESSON
Frontier	1	Geretsried, Germany	First closed-loop geothermal system implementation with commercialization targets	Eavor Technologies	Thermal performance closely matched model predictions, validating heat-transfer model and reservoir design approach
Frontier	2	Newberry, United States of America	Focuses on developing a superhot rock EGS with the potential to access supercritical geothermal fluids	Mazama Energy	Superhot rock EGS has transformative energy-density potential but requires deployed novel hybrid reservoir stimulation methods and advanced integrated modeling
Frontier	3	Project Red and Cape Station, United States of America	Pivotal transition from pilot-scale EGS demonstrations to commercially scalable deployment	Fervo Energy	Oil and gas tech transfer drives EGS risk and cost reduction. Each deployment improves drilling efficiency, reservoir design, and overall system performance, accelerating cost reduction over time
Frontier	4	Soultz-sous-Forêts, France	Developed over decades as research and pilot project established the scientific and technical foundation for modern EGS	Électricité de Strasbourg (ÉS) Géothermie	First sustained EGS electricity production from a deep fractured granite reservoir, demonstrating that multi-well circulation at ~5 km depth can yield usable wellhead conditions for binary conversion
Frontier	5	Utah FORGE, United States of America	A dedicated, publicly funded field laboratory strengthening the understanding of key mechanisms controlling EGS	DOE/ University of Utah's Energy and Geoscience Institute	Valuable open data for accelerating technology development by reducing duplication of effort and enabling broader collaboration across industry, academia, and government

GROUP	CASE STUDY	PROJECT, COUNTRY	FEATURES	OPERATOR	KEY LESSON
Mature Field	6	Berlin, El Salvador	One of the largest geothermal producers in Central America	LaGeo S.A. de C.V.	Geothermal energy can achieve a substantial share of national electricity generation when supported by long-term investment, resource development, and consistent energy policies
Mature Field	7	Hellisheidi, Iceland	World's largest combined heat and power geothermal plant	ON Power	Successfully combines large-scale geothermal energy production with applied research to improve reservoir management, validate emerging technologies, and advance development
Mature Field	8	Leyte, Philippines	Third largest geothermal producer globally. Initially developed under a build-operate-transfer scheme	Energy Development Corporation (EDC)	Build-operate-transfer structures mobilized private capital while preserving long-term public interest
Mature Field	9	Los Azufres, Mexico	More than four decades of commercial operation supported by adaptive reservoir management and continuous field development	Comisión Federal de Electricidad (CFE)	Matrix acidizing and selective hydraulic stimulation restored permeability and improved wellbore performance in declining producers and injectors
Mature Field	10	Salak, Indonesia	Largest producing geothermal field in Indonesia with an installed power generation capacity of 377 MWe	Star Energy Geothermal Salak, Ltd	The field has maintained a high net capacity factor over 90%, supported by reinjection and adaptive reservoir management strategies. The Geothermal Law was critical enabler.
Mature Field	11	Sumikawa, Japan	Plant located near tourist and natural attractions, including hot springs, ski resorts, and scenic glens	Tohoku Sustainable & Renewable Energy Co. Inc and Mitsubishi Materials Corporation	Cold-water stimulation/reinjection campaigns that improved injectivity and helped sustain productivity in multiple wells, while monitoring and mitigation practices limit scaling, corrosion, and induced seismicity
Early Stage	12	Kingdom of Saudi Arabia's Red Sea Coast, Kingdom of Saudi Arabia	Exploration of medium-enthalpy geothermal resources hosted in deep rift-basin sedimentary aquifers	King Abdullah University of Science and Technology (KAUST)	The use of shallow, highly instrumented pilot well helped de-risk geothermal development by delivering essential subsurface data
Early Stage	13	Tocomar Geothermal System, Argentina	Proximity to emerging Central Puna Energy Hub	Consejo Nacional de Investigaciones Científicas y Técnicas (CONICET)	A strong candidate for supplying reliable energy to support mining operations and complement power in the Central Puna region

The report concludes with a decision framework for CEM member countries seeking to define and develop their optimal geothermal pathway, along with options for financing structures, policy considerations, and the potential role of international cooperation.

Section 1:

Introduction: From Resource Constraint to Global Opportunity

Geothermal energy has long been recognized as a reliable, baseload energy source. Its defining characteristics—continuous, dispatchable power—make it different from other energy resources. Geothermal can provide firm, domestic, and secure power independent of weather conditions. In global energy systems, this reliability has substantial value.

Yet for most of the twentieth century, commercial geothermal development was constrained by a fundamental limitation: the requirement for naturally occurring hydrothermal resources. Conventional geothermal plants require the combination of heat, permeability, and fluid at accessible depths, a combination that occurs naturally in only a small number of geographies. This has historically confined large-scale development to volcanic regions and active tectonic boundaries: Iceland, Indonesia, the Philippines, New Zealand, Kenya, and parts of the western United States.

Next-generation geothermal technologies alter this paradigm. By enabling heat extraction from dry rock formations, deep reservoirs, and engineered subsurface systems, these technologies expand geothermal's applicability from a niche resource into a globally deployable energy solution.

1.1 Technology Advancement

Three major developments are driving this progress.

First, advances in drilling technology, particularly horizontal drilling, multi-well pad design, and high-temperature materials, have significantly improved penetration rates, quickened operations, and minimized downtime, consequently reducing cost. Many of these innovations come from the oil and gas sector, where decades of intensive investment drove rapid technological progress.

Second, developments in reservoir engineering are delivering significant performance gains, reducing uncertainty, and improving operational control. These advances include hydraulic fracturing, hybrid stimulation methods, the use of thermal stress to enhance permeability, and real-time reservoir monitoring. Their impact is evident in projects such as Fervo Energy's

Project Red and Cape Station, Newberry Volcano in the United States, and Sumikawa in Japan. Field testing at Soultz-sous-Forêts in France and Utah FORGE in the United States has also been instrumental, producing open-access datasets that are accelerating global learning and innovation.

Third, the emergence of new systems designs, particularly closed-loop systems explored by companies such as Eavor Technologies, has introduced an alternative approach that does not depend on naturally permeable reservoirs, though questions remain about their predictability and cost at commercial scale.

Additional improvements in subsurface characterization to reduce risk, including distributed fiber-optic sensing, advanced seismic imaging, and highly instrumented pilot wells provide critical data to assess geothermal resources.

1.2 The GeoFuture Initiative

The GeoFuture Initiative was established within the Clean Energy Ministerial to accelerate the development of next-generation geothermal at scale. Its mandate is to help countries evaluate and deploy next-generation geothermal technologies by:

1. Synthesizing global sources of information related to technology performance, cost, and risk
2. Developing shared frameworks for decision-making and project evaluation
3. Facilitating knowledge exchange among CEM member countries
4. Connecting national decision-makers with technical expertise and international finance.

This Case Study Series is one of the primary outputs of the Initiative, developed through consultations with national governments, technical partners, and project developers, and drawing on publicly available information. It draws on 13 geothermal projects spanning four types of technology and development pathways, 11 countries, and a range of development stages,

from fundamental research to commercial operation. The series is designed to be directly useful to energy ministers, national planners, project developers, and investors seeking to understand what next-generation geothermal can deliver, what it costs, and how to make it happen.

1.3 How to Use This Report

The report is organized in eight sections, mirroring the decision pathway that countries and developers face when considering geothermal deployment:

1. Introduction
2. Decision Context: Understanding the conditions, constraints, and drivers that shape technology choice
3. Technology Pathways: A structured overview of conventional hydrothermal, EGS, closed-loop, superhot rock, and hybrid approaches
4. Case Studies: Detailed evidence from 13 global projects
5. Evaluation Framework: Criteria and methods for assessing geothermal options
6. Decision-Relevant Outputs: Frameworks for translating case study lessons into national action
7. Key Takeaways: Synthesis of the most important lessons for CEM partners
8. Enabling Conditions and Pathways to Scale

This report is written for a broad, international audience with different starting points and different questions. Energy ministers and national planners may find the most direct value in Section 2 (Decision Context), Section 6 (Decision-Relevant Outputs), and Section 8 (Enabling Conditions), which translate case study evidence into a country-level action sequence. Utilities and project developers may find Section 3 (Technology Pathways), Section 4 (Case Studies), Section 5 (Evaluation Framework), and the case studies themselves most directly useful for technology selection and project design. Investors and financiers may find Section 5.3 (Financing and Risk Profile), Section 6.3 (Identification of Bankable Opportunities), and the financing details within each case study most relevant to underwriting decisions. Readers new to geothermal in general are encouraged to begin with Section 1 and Section 3 before proceeding to the case studies.

Section 2:

Decision Context: Conditions, Constraints, and Drivers

The decision to invest in next-generation geothermal is shaped by a complex interaction of national energy goals, resource endowments, regulatory environments, and financing realities. No two countries face identical conditions, and no single technology pathway is optimal across all contexts. This section provides a structured framework for understanding the factors that shape geothermal decision-making.

2.1 National Energy Goals and Security Needs

An important driver of geothermal investment is the recognition that firm, dispatchable energy has a distinct and valuable role in grid stability and security. As grids increasingly incorporate variable energy sources, the grid integration value of baseload resources increases. Countries with ambitious energy growth and energy security targets, but limited hydropower and hydrocarbon resources to serve as alternative firming resources, face strong incentives to develop geothermal as a firming resource.

Energy security considerations are also highly relevant. Geothermal resources are domestic and are not subject to import risk, price volatility, or supply chain disruption. For island nations, remote communities, and countries with limited grid interconnection, this domestic resource security has significant strategic value.

The growth of large, continuous loads, including data centers, mining and mineral processing operations, manufacturing facilities, and other industrial users, is intensifying demand for firm power in many markets. These loads share a need for reliable, round-the-clock electricity and increasingly seek long-term supply arrangements, although their specific requirements vary. Data centers require firm power alongside significant cooling capacity, e.g., Fervo Energy's, Sage Geosystems', and XGS Energy's power purchase agreements with hyperscale data center operators;; mining and mineral processing operations may value continuous power together with process heat for extraction and refining; and manufacturing facilities can benefit from stable, predictable energy costs over long investment horizons. These characteristics are creating

potential opportunities for geothermal offtake where suitable resources and grid or direct-use infrastructure are available.

Key Decision Driver: The Value of Firm Power

As variable energy penetration increases, the value of dispatchable, non-variable generation rises. Analysis from NLR's Annual Technology Baseline (2024) indicates that the grid integration value of firm resources, including geothermal, can add \$20–50/MWh to the effective value of power, above and beyond the levelized cost of electricity (LCOE) comparison with other sources. For countries looking to integrate high contributions of variable generation, this integrated system value should be central to geothermal investment decisions.

2.2 Resource Quality and Data Availability

Geothermal resource quality varies significantly by location. Key factors include:

RESOURCE ATTRIBUTE	SIGNIFICANCE FOR PROJECT DEVELOPMENT
Temperature gradient (°C/km)	Higher gradients allow shallower, less costly wells to achieve target temperatures
Permeability degree	Determines whether conventional development is feasible or if next-generation technologies are required
Rock type and geology	Crystalline basement and hot sedimentary rocks are well-suited for conventional and next-generation technologies
Seismic context	Active tectonic zones may offer better resources, but increase risk management requirements for induced seismicity
Data availability	Existing geophysical surveys, oil and gas well data, and academic studies reduce exploration costs significantly

Countries with existing oil and gas sectors often have significant relevant subsurface data, well logs, seismic surveys, and temperature measurements that can reduce geothermal exploration costs and risk. Repurposing these data for a geothermal assessment is an important early step for many nations.

2.3 Cost, Financing, and Investment Readiness

Geothermal projects are highly capital-intensive, and enhanced geothermal systems (EGS) have historically been more costly than conventional hydrothermal power projects. The levelized cost of electricity (LCOE) for EGS has been estimated at approximately \$60 to \$100 per megawatt-hour (DOE 2019). However, recent results from Fervo's drilling, stimulation, and well testing activities at its Cape Station site further reinforce the broader trend of declining EGS costs. Under the 2024 Annual Technology Baseline (ATB) Moderate Scenario, EGS is projected to reach cost parity with 2024 flash hydrothermal LCOE within the next decade (NLR, 2024; Akindipe, et al., 2026). These figures compare favorably with other firm options, particularly when grid integration value is considered, but the upfront capital requirement and long development timeline create significant financing challenges.

The key determinant of financing viability is subsurface risk. Projects with strong resource data, demonstrated well performance, and validated reservoir behavior can access conventional project financing. Projects in early exploration phases or novel technology applications typically require concessional finance, public investment, or specialized risk-sharing mechanisms.

2.4 Regulatory and Permitting Environment

Regulatory clarity is consistently identified across case studies as a precondition for private investment. Key regulatory factors include:

1. Definition of geothermal resources in law (separate from mining law, water law, or energy law)
2. Permitting timelines for exploration and production drilling
3. Land access and subsurface and surface rights frameworks
4. Induced seismicity monitoring and response requirements
5. Grid connection standards and interconnection agreements
6. Power purchase agreement frameworks and offtake security.

Experience across this report's case studies, including Hellisheiði (Iceland), Leyte (Philippines), and Berlin (El Salvador), and globally, suggests that clearer and more coordinated regulatory and permitting frameworks are associated with faster, lower-risk project development compared with jurisdictions where geothermal regulation is fragmented or uncertain (Gehring and Loksha, 2012; IEA, 2024).

2.5 Barriers to Deployment

Even where the drivers described above are strong, five recurring barriers slow next-generation geothermal from reaching financial close and construction. The case studies in this series illustrate each of them, and each has a documented path to resolution.

1. **Subsurface and technical risk.** A geothermal well carries a certain level of uncertainty, since temperature, permeability, and fluid chemistry cannot be fully known until wells are drilled and flow tested, and early wells can fail to perform as modeled. This is the single largest reason geothermal projects stall before construction. Public research infrastructure like the field laboratory in the Utah FORGE Case Study and the Soultz-sous-Forêts demonstrator along with advanced subsurface modeling tools and more open geothermal datasets can help to reduce this uncertainty before a country or developer commits capital.
2. **Financing gap between exploration and construction.** Exploration drilling is risky for commercial lenders and expensive for most developers to self-fund, while construction debt is usually only available once a resource is proven. This gap, sometimes called the "valley of death" in project finance, has stalled promising resources in multiple CEM member countries. Salak and Los Azufres Case Studies presented in this report both show how public co-investment or state utility ownership can bridge this gap; the Berlin Case Study shows how a small country can do the same at a smaller scale through concessional and multilateral funding.
3. **Regulatory and permitting fragmentation.** In many countries, geothermal falls under mining law, water law, or general energy law, none of which were written with geothermal's specific combination of subsurface access, reinjection, and long-lease development timelines in mind. Indonesia's experience, where a dedicated geothermal law separated development from mining law restrictions, is the clearest example in this series of what resolving this barrier can look like in practice.

4. **Workforce and supply chain constraints.** Drilling rigs, reservoir engineers, and geothermal-specific plant technicians are in short supply outside of a handful of established markets. Countries with active oil and gas sectors, such as several CEM members in Latin America, the Middle East, and Southeast Asia, hold an underused advantage here: Much of the workforce and equipment base transfers directly, as shown in the Fervo Case Study, where they use oil and gas drilling teams.
5. **Environmental and social risk management.** Water use, land access, induced seismicity, and impacts on protected areas or tourism (as highlighted in the Japan Case Study) all require early, transparent engagement to avoid costly delays later. The community benefit programs and wildlife park in Berlin's Case Study, and public seismic monitoring data in Hellisheidi's Case Study, are examples of building social support for large-scale development.

Barrier Patterns Observed Across the Case Studies

Every case study in this series encountered at least one of these five barriers directly. In the Philippines, the Leyte geothermal field's 2025 production decline reflects the ongoing technical and asset management challenge of operating a field for four decades. In El Salvador, the Berlin Case Study's history shows a small economy working through the financing gap using concessional and multilateral capital. Meanwhile, Salak's pre-2003 regulatory environment in Indonesia illustrates the cost of an unclear legal framework, and the field's post-law trajectory illustrates the return on fixing it. Finally, Utah FORGE functions as a public field laboratory, generating and openly sharing subsurface data that might not otherwise be broadly available across the industry.

Section 3:

Conventional and Next-Generation Geothermal Technology Pathways: What Options Exist?

Next-generation geothermal is not a single technology, but a portfolio of approaches with distinct characteristics, advantages, and limitations (Figure 1). Understanding these differences is essential for effective decision-making. This section provides a structured overview of each major pathway and the conditions under which each is most applicable. Next-generation approaches are not designed to replace conventional hydrothermal geothermal technologies, which remain the most cost-effective option in favorable settings. Their value lies in expanding geothermal opportunities where site conditions and planned applications make them a strong fit.

3.1 Conventional Hydrothermal Systems

Conventional hydrothermal systems are the baseline geothermal technology against which next-generation approaches are compared. These systems rely on naturally occurring reservoirs, permeable rock formations that already contain sufficient heat, fluid, and pathways for that fluid to circulate, typically at depths of less than 3 kilometers. Where temperatures and flow rates are favorable, hot fluid or steam is brought to the surface to drive flash or dry-steam turbines, or lower-temperature resources are used in binary cycle plants (DOE, 2019; Akindipe et al., 2026).

The primary advantage of conventional hydrothermal is that it is a mature, well-understood technology with decades of commercial operating history, and where naturally favorable geology exists, it remains the most cost-effective geothermal pathway available (Gehring and Loksha, 2012; DOE, 2019). All six of this report's mature-field case studies, Berlin (El Salvador), Hellisheiði (Iceland), Leyte (Philippines), Los Azufres (Mexico), Salak (Indonesia), and Sumikawa (Japan), illustrate conventional hydrothermal development at commercial scale, each relying on some form of stimulation to sustain or extend field performance (Pollack et al., 2021). Its central limitation is geographic: the naturally occurring combination of heat, permeability, and fluid required is confined to a relatively narrow set of tectonic and volcanic settings, which is precisely the

constraint that next-generation approaches such as EGS and closed-loop systems are designed to work around.

3.2 Enhanced Geothermal Systems

Enhanced geothermal systems (EGS) represent the most mature pathway toward large-scale deployment beyond naturally occurring hydrothermal resources. EGS designs rely on engineered rock fracture networks that link multiple wells, allowing fluids to circulate underground and recover heat. These fractures are created through stimulation techniques such as hydro-shearing in formations that already contain some natural fractures, and hydraulic fracturing in formations with few or no existing fractures, where more planar fracture networks are formed (Akindipe et al., 2026). Enhanced geothermal systems (EGS) enable geothermal development in less favorable settings by increasing rock permeability and improving fluid circulation, which allows heat to be more effectively extracted by the circulating fluid (Horne et al., 2025)

The primary advantage of EGS is its scalability. Because EGS does not depend on naturally occurring permeability, it can in principle be developed across a much broader range of geological settings than conventional hydrothermal resources (Tester et al., 2006; DOE, 2019). **However, EGS also presents several challenges.** Subsurface uncertainty remains a key issue, because creating sufficient and well-distributed permeability for effective heat sweep while avoiding short-circuiting requires detailed site characterization, iterative testing, and careful control of fracture growth and connectivity (Tester et al., 2006; McClure & Horne, 2014). Induced seismicity is another important concern: multiple sites have temporarily ceased operations or shut down because of induced seismicity concerns (Pollack et al., 2021). Hydraulic stimulation can trigger small but detectable seismic events and therefore requires close monitoring and operational controls such as traffic-light protocols (Majer et al., 2007; DOE, 2015). In addition, reservoir production must be managed over time to maintain long-term heat extraction and fluid circulation within engineered fracture networks (Tester et al., 2006). EGS operations can have a high underground reservoir

fluid losses, that require makeup water. To mitigate local environmental impacts, particularly in water-stressed regions, projects can evaluate compatible degraded or low-quality water sources for makeup injection where technically and environmentally appropriate (Schroeder, et al., 2013). Regulatory and financing barriers have also hindered EGS project development. Because EGS projects can remain high-risk investments, they often face significant financing challenges, while regulatory requirements and permitting processes can cause delays and, in some cases, contribute to project cancellation (Pollack et al., 2021). Despite these challenges, progress at Utah FORGE and commercial projects such as Fervo Energy's Project Red and Cape Station indicates that EGS and related next-generation geothermal systems are increasingly moving from research and demonstration toward commercial deployment.

3.3 Closed-Loop Geothermal Systems

Closed-loop geothermal systems represent a fundamentally different approach. This technology is defined as the development or expansion of a geothermal system that transfers subsurface heat to the surface for power generation by circulating a working fluid through a wellbore without direct interaction with the geothermal reservoir. This includes closed-loop systems and other downhole heat exchanger technologies (Akindipe, et al., 2026).

Closed-loop geothermal systems offer several **potential advantages** for investors and developers, including avoidance of hydraulic stimulation, reduced reliance on naturally permeable reservoirs, and performance that depends more strongly on well design and rock thermal properties than on uncertain reservoir behavior (Beckers et al., 2023). Because these systems do not require fluid injection into the formation, they may also face lower induced-seismicity risk and, in some jurisdictions, simpler permitting pathways than EGS projects (DOE, 2015; Beckers et al., 2023). In addition, closed-loop designs may be deployable in a broader range of geological settings, including areas lacking high natural permeability (Beckers et al., 2023; DOE, 2019). However, **these systems also face tradeoffs**: heat extraction is constrained by wellbore surface area and conductive heat transfer from surrounding rock, which can limit thermal efficiency and power output per well relative to high-performing convective geothermal systems (Beckers et al., 2023). As a result, they may be better suited to some direct-use heat and moderate-scale power applications than to very high-output generation. Eavor's Geretsried project in Germany one of the most advanced commercial-scale demonstrations of this approach (Eavor Technologies, 2026). Closed-loop geothermal could also provide a

practical heat source for industrial and utility applications such as desalination and, potentially, district cooling (Maver and Kalogirou, 2025).

Closed-Loop Geothermal Systems Beyond Power Production

Maver and Kalogirou (2025) present a closed-loop horizontal geothermal well concept aimed at supplying low-enthalpy heat for seawater desalination, particularly in Gulf Cooperation Council countries where desalination accounts for a significant share of energy consumption.

The concept is designed to match the temperature requirements of thermal desalination processes such as multi-effect distillation. The proposed well is modeled to deliver approximately 1.5–2.5 MWth per well, with long-term surface temperatures around 90°C from subsurface conditions near 150°C.

This illustrates that closed-loop geothermal systems have potential applications beyond power generation, including industrial and utility uses such as desalination and, potentially, district cooling, though this remains a conceptual design rather than a demonstrated deployment.

Characteristics cited by the authors include low operational risk, reduced maintenance requirements, and long project life with proper design.

3.4 Superhot Geothermal Systems

Superhot geothermal systems access resources at temperatures above 375°C. When water is injected into these extremely hot conditions, it becomes hot enough to exhibit properties of both a liquid and a gas (supercritical state), enabling it to carry very large amounts of heat energy (DOE, 2026). Theoretical analysis suggests that a single supercritical well could deliver 10 times the power of a conventional geothermal well at the same flow rate (Friðleifsson et al., 2003; Cladouhos et al., 2018; Cladouhos, 2024). As a result, the superhot rock pathway could significantly improve geothermal economics and alter the technology's long-term cost trajectory by increasing power output per well and potentially reducing the number of wells needed for a given project capacity (Friðleifsson et al., 2003; Cladouhos et al., 2018).

At the same time, superhot rock remains in the early stages of development and faces several major technical challenges. Drilling and well construction are difficult

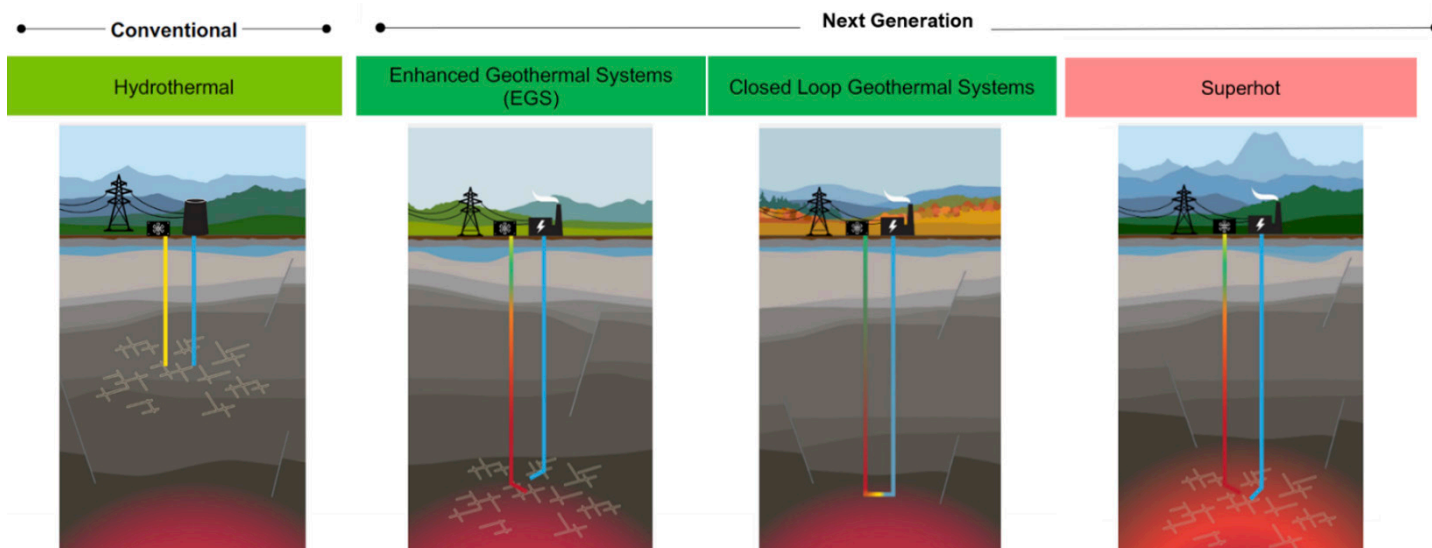


Figure 1. Comparison of conventional and next-generation geothermal technologies, including hydrothermal, enhanced geothermal systems (EGS), closed-loop geothermal systems, and superhot rock concepts, highlighting the progression toward deeper, hotter, and more widely deployable geothermal resources. Image from DOE (2026).

because conventional casing, cement, and wellhead components have limited performance at supercritical conditions, requiring new materials and engineering approaches (Cladouhos et al., 2018). Fluid chemistry presents another obstacle, as high-temperature geothermal fluids can be highly reactive and corrosive, creating risks for well integrity and surface equipment unless specialized materials and controls are used (Tester et al., 2006; Cladouhos et al., 2018). Reservoir access is also a limiting factor, since reaching supercritical conditions outside volcanic or magmatic settings often requires drilling to depths greater than 5,000 meters, which substantially increases technical complexity and cost (Friðleifsson et al., 2003; Cladouhos et al., 2018). In the United States, Mazama Energy's Newberry Volcano project in Oregon is one of the leading superhot rock demonstration efforts and is contributing valuable data on subsurface conditions, drilling performance, and engineering solutions for future development (DOE Geothermal Technologies Office, 2024; Mazama Energy, 2026).

3.5 Hybrid and Emerging Concepts

Several emerging approaches combine elements of the above pathways with other technologies:

1. **Geothermal + Direct Lithium Extraction:** Co-production of lithium from geothermal brines, with potential to improve project economics in lithium-bearing formations. An example is Controlled Thermal Resources' Hell's Kitchen project at the Salton Sea, California, broke ground in January 2024 and is targeting approximately 25,000 tonnes per year
2. **Geothermal Coproduction with Oil and Gas and Well Conversion:** Conversion of existing wells in oil and gas fields to geothermal production, leveraging existing infrastructure and surface rights. DOE's Wells of Opportunity: ReAmplify program awarded \$8.4 million across four FY2024 pilot projects converting hydrocarbon wells to geothermal use, including GEOTHERMIX in the Austin Chalk formation, ICE Thermal Harvesting at the Elk Hills oil field in California, Gradient Geothermal at the Blackburn oil field in Nevada, and the University of Oklahoma (DOE Geothermal Technologies Office, 2024). Transitional Energy has separately demonstrated this approach with private capital at the Grant Canyon oil field in Nevada, using Organic Rankine Cycle units to generate electricity from oilfield waste heat since 2022.
3. **Geothermal District Heating Integration:** Combination of power generation and direct heat supply to improve total resource utilization and project economics, as illustrated by Case Study 7 in this report, Hellisheiði (Iceland), which pairs roughly 303 MWe of power generation with about 200 MWth of district heat piped to the greater Reykjavík area.

Section 4:

Case Studies: Global Information From 13 Highlighted Projects

The following case studies present information from 13 geothermal projects spanning four types of technology and 11 countries. Each case study is structured around the same framework: decision context, technology pathway selected, key performance outcomes, financing and policy lessons, and implications for replication. Each case study synthesizes operator-provided information, public project documentation, and peer-reviewed literature.

Why These 13 Case Studies Were Selected

The 13 case studies that follow were chosen because, together, they cover the situations a CEM member country is likely to face when evaluating next-generation geothermal: an untested resource, an aging field in decline, a tight regulatory environment, a shortage of risk capital, or public lack of awareness. Each case study answers a different version of the same question that runs through this report: what does it take to move geothermal from a resource a country happens to have, to a resource it can finance, build, and operate at scale.

The set breaks into three groups: (1) Five projects sit at the technology frontier, where the central question is whether a new approach works at all and what it costs to find out. (2) Six projects are mature or maturing hydrothermal fields, where the question is how to sustain, extend, or expand output from a resource that is already producing power. (3) Two projects are in early stage of prospecting where de-risking development is its main goal.

Among the frontier projects, Case Study #1, the Geretsried project, was selected because it addresses resource risk differently from the others. Its closed-loop design does not rely on natural permeability or induced fracturing, offering a potentially lower-risk pathway for countries or investors that are less willing to accept subsurface uncertainty. At the same time, the project encountered challenges and required adaptive steps during development, making its experience valuable for informing future closed-loop geothermal projects. Case Study #2, Mazama Energy's Newberry Volcano project, was included as a technology-frontier case because its 2025 EGS demonstration created a reservoir in rock reported at approximately 330°C, illustrating progress toward superhot-rock conditions and the

technical challenges that remain. Case Study #3, Fervo Energy's Project Red and Cape Station, was selected as evidence that oil and gas drilling techniques can transfer to geothermal at commercial scale, supported by an operating power purchase agreement rather than a pilot well alone. The Soultz-sous-Forêts project in France was selected as Case Study #4 because it demonstrated sustained power generation from a deep EGS system, confirming that deep multi-well circulation can provide viable production conditions. Utah FORGE was included as Case Study #5 not for generating capacity, but for its role as a publicly funded research field laboratory that makes well-performance and stimulation data broadly available, providing insights that can reduce uncertainty and support technology development and investment.

Among the mature field case studies, the Berlin Case Study #6 was selected to show how a country with modest financial resources built geothermal into roughly a quarter of its national electricity supply, and how a binary cycle addition can add capacity to an existing field without new exploration risk. Case Study #7, Hellisheiði, was selected because it combines mature hydrothermal operation with large-scale district heating and associated innovation, including the CarbFix carbon mineralization program, showing how an operating geothermal complex can support multiple energy and environmental applications. The Leyte project (Case Study #8) was selected deliberately because its build-operate-transfer financing structure and multi-decade production history are instructive, while its recent recovery efforts following production decline provide insight into long-term field management. Los Azufres was selected as Case Study #9 to show that a four-decade-old field can remain a site of active engineering, using acid stimulation and reinjection management to sustain performance. Case Study #10, Salak, was selected as an example of public-private risk sharing in an emerging market and of the role that a dedicated geothermal law can play in enabling development. Sumikawa was selected as Case Study #11 because Japan's regulatory environment, shaped by proximity to national parks and hot spring tourism, highlights the importance of public acceptance and environmental management, while its low-seismicity cold-water stimulation approach

responds to those constraints. These six cases are part of the 64 projects analyzed by Pollack et al. (2021) that use different types of stimulation as part of field operations. The last two cases, the early-stage Red Sea Coast project in the Kingdom of Saudi Arabia (Case Study #12) and the Tocomar project in Argentina (Case Study #13), show that geothermal exploration risk can be reduced through advanced measurement techniques and integrated, multidisciplinary site characterization. In the Red Sea Coast sedimentary aquifers, a shallow, highly instrumented pilot well can be an effective early de-risking step, providing critical data to refine the conceptual model and support subsequent drilling

decisions. More broadly, the Tocomar case illustrates how combining geophysical, geochemical, geological, and temperature data can help constrain subsurface uncertainty before costly deep drilling begins, particularly when assessing geothermal potential near an energy hub.

Read together, these 13 projects are intended to serve as a broad reference set rather than a collection of uniform case studies. A country beginning to evaluate geothermal energy should be able to find at least one case study here that resembles its own starting point, and use that project's experience, including if and where it fell short of plan, as a starting point for its own planning.

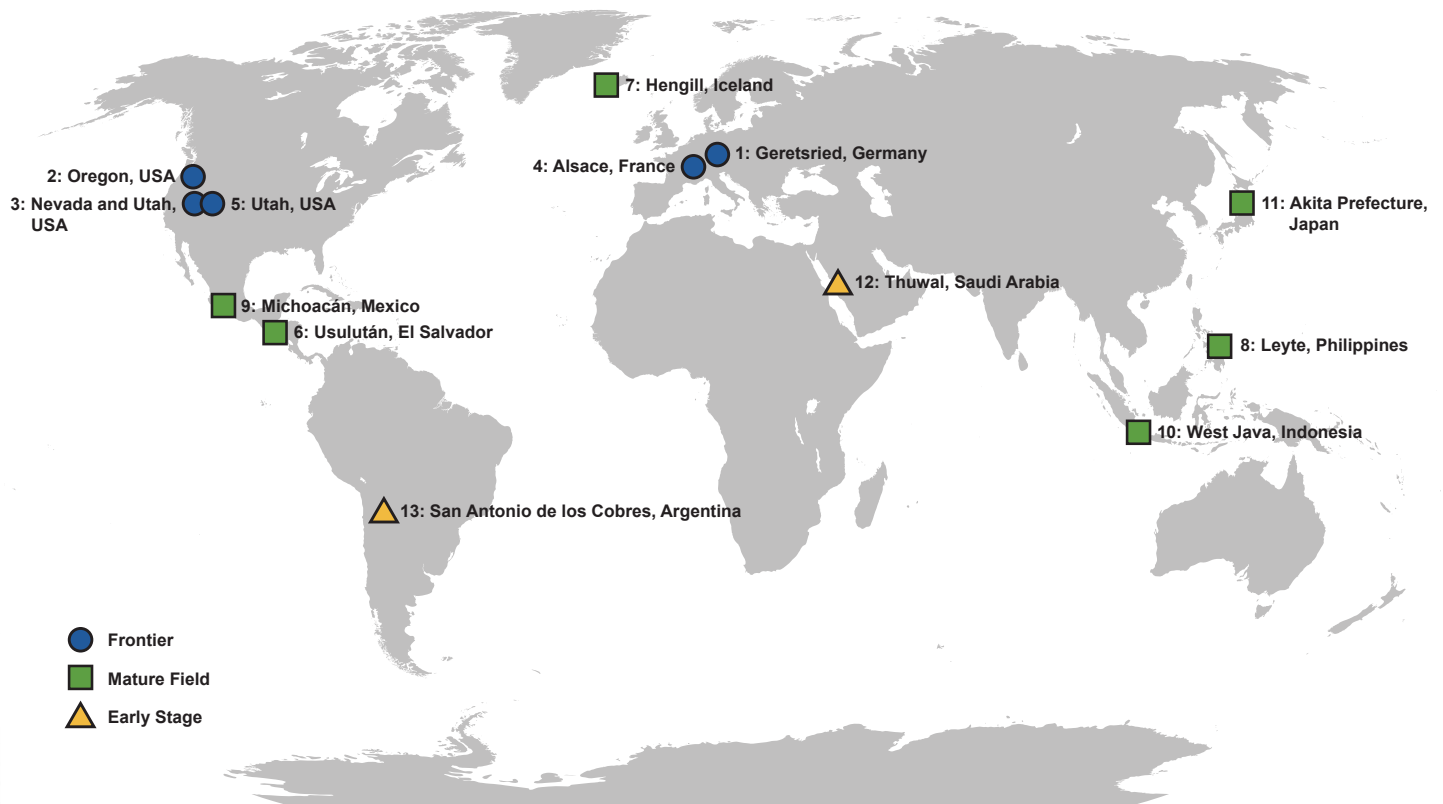


Figure 2. Map of the 13 case studies presented in this report

GERETSRIED, GERMANY

Case Study 1:

Geretsried — Implementation of the First Closed-Loop Geothermal System

Operator:
Eavor Technologies Inc.

Partners:
European Investment Bank, European Union Innovation Fund, regional utilities, and industrial heat users

KEY CHARACTERISTICS

**FINANCING:**

Combination of private investment, strategic energy-sector investors, grants, and banks. The project received €91.6 million grant from the EU Innovation Fund and approximately €45 million from the European Investment Bank.

**EXPERTISE:**

Multilateral well design and construction, engineering mud systems, bit and bottom hole assembly design, well-understood cementing design and industry best practices, magnetic ranging, and well intersection technologies.

**IMPACT:**

First closed-loop geothermal system implementation.

**POWER PRODUCTION:**

Planned Total Capacity

Electrical Capacity:
Approximately 8.2 MWe

Thermal Capacity:
Approximately 64 MWth

Application:
Combined heat and power (CHP), supplying electricity to the grid and district heating to the city of Geretsried.

Type of Plant Planned:
Organic Rankine cycle binary power plant integrated with district heating infrastructure.

**ROCK TYPE:**

Sedimentary, deep carbonate reservoir of the Upper Jurassic (Malm) Formation, consisting predominantly of carbonates.

**TEMPERATURE:**

155–165 °C
(311–329 °F)

**DEPTH:**

4,500–5,000 m
(14,763–16,404 ft) true vertical depth, laterals extending beyond 7 km measured depth.

Located in southern Germany's Bavarian Molasse Basin, the Geretsried project is the first commercial-scale implementation of Eavor's closed-loop technology. The project uses a sealed multilateral loop system to extract geothermal heat through conductive heat transfer from deep subsurface formations, an approach that does not depend on naturally permeable reservoirs, hydraulic stimulation, or geothermal fluid production. The design combines directional drilling, precise wellbore intersections, and thermosiphon-driven circulation. The project faced execution challenges and required adaptation during development, and its results to date offer lessons for future closed-loop geothermal projects on both the technical and commercial viability of the approach at scale.

Overview

The Geretsried Geothermal Project, located in the Bavarian Molasse Basin of southern Germany, is the first commercial-scale deployment of Eavor's closed-loop geothermal technology.

The site was previously assessed for conventional geothermal development, but development did not move forward: Temperatures were high, but the subsurface lacked sufficient natural permeability a conventional reservoir requires.

The project uses directional drilling, precision well intersections, and closed-loop heat extraction to test whether the technology can operate at commercial scale (Eavor Technologies, 2026). The system was designed to deliver approximately 8.2 MWe of electricity or 64 MWth of thermal energy for district heating applications when fully complete as designed with four Eavor-Loops. Currently one loop is contributing power to the grid, with the remaining loops to come in order to achieve capacity and efficiency as designed.

The project is supported by private investment, the European Investment Bank, and the European Union Innovation Fund. Its results will help clarify whether closed-loop systems can offer a path to baseload geothermal energy with lower water use and reduced subsurface risk in locations without a naturally permeable reservoir.



Aerial view of the Geretsried site located at the Bavarian Molasse Basin of southern Germany. Source: Eavor Technologies Inc.

Closed-Loop Testbed in Alberta, Canada

As a precursor to the Geretsried commercial project, Eavor Technologies, in 2019, built and operated a small-scale demonstration of its system near its headquarters in Alberta. Known as Eavor-Lite, the demonstration used a simplified design, with two lateral sections connecting two vertical wells spaced about 2,000 m apart at a depth of roughly 2,400 m.

The small-scale site demonstrated the core technological principles of the operator's designs while avoiding the substantial capital cost of constructing a full-scale commercial plant. The reduced-scale installation has produced close to 20 GWhth and after 4 years of operation, the outlet temperature has remained stable at about 50°C (Zatonski & Brown, 2023). Key features

at the site include the ability to drill and intersect lateral wellbores with vertical wells using magnetic ranging technology, the use of the proprietary Rock-Pipe sealing system to line uncased lateral sections during drilling and seal near-wellbore permeability, and the creation of a thermosiphon effect within the system (Toews & Holmes, 2021).

Site Geology

The Geretsried geothermal project is located in the Bavarian Molasse Basin of southern Germany and targets the deep Upper Jurassic Malm carbonates, the principal geothermal reservoir of the basin. At Geretsried, conventional hydrothermal productivity proved lower than expected, which increased interest in closed-loop development concepts. At depths of roughly 4.5–5.0 km, reported temperatures are on the order of 155–165°C (Dussel et al., 2021), generally suitable for both district heating and electricity generation.

Operational Critical Challenges

The Geretsried site is designed to include four full loops, each made up of multiple lateral well pairs that function as a subsurface heat exchanger. When the project encountered execution setbacks, it transitioned from parallel drilling to sequential operations, significantly affecting both schedule and cost. As a result, drilling timelines approximately doubled, overall costs rose substantially, and Loop 1 was reduced from 12 planned lateral pairs to six pairs in order to move ahead to commissioning and proving the technological components. The four clean lateral pairs are reportedly producing approximately the expected thermal energy, at roughly 2 MWth per pair initially, which aligns closely with pre-drill modeling.

Another challenge-solution pair was regarding the drilling fluid. The fluid system was originally modeled on approaches that had worked well in traditional geothermal wells in southern Germany, but it proved poorly matched to the carbonate formation behavior encountered in the laterals. In particular, weak bedding planes, hole-cleaning difficulties, and the associated risk of stuck pipe reduced performance early in the campaign. The solution was straightforward: The team switched to an engineered mud system better suited to the formation, which is expected to serve as the baseline for future loops. Following that change, wellbore stability issues were brought under control.

Key Achievements

- Despite the drilling and construction complications, the system appears to have achieved its primary performance objective: thermal output in line with expectations.
- Demonstrated thermal production consistent with pre-drill modeling predictions, validating closed-loop reservoir and heat-transfer design methodologies.
- Drilled and connected six commercial-scale lateral pairs at depths exceeding 8 km measured depth, proving the feasibility of long-reach multilateral geothermal well construction.
- Implemented and validated completion technology, achieving negligible fluid loss rates and demonstrating effective long-term fluid containment within the closed-loop system.
- Proved the effectiveness of magnetic ranging and well intersection technologies, achieving successful intersections on all six lateral pairs and significantly reducing ranging time through the deployment.

Lessons Learned

- Wellbore stability and hole cleaning are critical for efficient drilling in deep carbonate formations and can be improved through optimized drilling fluid systems.
- Active magnetic ranging systems dramatically improve the speed and accuracy of wellbore intersections, increasing operational efficiency.
- Cement isolation and well integrity are key design considerations for multilateral closed-loop systems, with lessons from Geretsried informing improved future well construction practices.
- Thermal performance closely matched model predictions, validating heat-transfer model and reservoir design approach.
- Sustained engagement with local communities can strengthen project support, improve planning efficiency, and lay the groundwork for future heat-use applications. In this case, outreach over the past decade helped advance district heating plans and positioned the project to move more quickly.

Status and Outlook

Despite drilling and execution challenges, the company has reported improvements in efficiency and cost over the course of the project. The Geretsried project is intended to support the expansion of closed-loop technology in the European market, and the lessons learned may be useful for future projects elsewhere.

This learning curve shows the path forward to continued progress and the ability to come down the cost curve, as historically demonstrated with other new technology implementations.



Geretsried site infrastructure. Source: Eavor Technologies Inc.

OREGON, USA

Case Study 2:

Newberry — Superhot Rock Enhanced Geothermal Systems

Operator:
Mazama Energy

Partners:
U.S. Department of Energy, National Laboratory of the Rockies, Lawrence Berkeley National Laboratory, Pacific Northwest National Laboratory, Oregon State University, University of Oklahoma

KEY CHARACTERISTICS

**FINANCING:**

Development-stage private + R&D-driven investment structure.

**EXPERTISE:**

High-temperature reservoir hybrid stimulation techniques. Developing capabilities in designing systems for ultra-high temperature >400°C energy extraction and optimization.

**IMPACT:**

U.S. testbed for superhot rock geothermal systems. This is the hottest EGS to date globally.

**POWER PRODUCTION:****Planned Total Capacity**

Approximately 200 MWe
First grid connection targeted by 2029.

Type of Plant Planned:
Steam turbine, possible hybrid option.

**ROCK TYPE:**

Bimodal volcanic composition dominated by basaltic andesite and rhyodacite, with frequent intrusive bodies such as granodiorite and felsic dikes and sills.

**TEMPERATURE:**

380°C (716°F)

**DEPTH:**

3,800 m (12,467 ft)

Located within one of the largest estimated geothermal reservoirs in the United States, the Newberry project is demonstrating the technical and commercial feasibility of EGS in hot crystalline rock. The project's results provide a validated foundation for scaling next-generation geothermal systems capable of delivering continuous baseload power globally. Mazama Energy is advancing this effort through innovative wellbore construction, stimulation, and drilling techniques, positioning the Newberry Volcano project as a major step forward in superhot rock geothermal development. The Newberry project is laying the foundation for large-scale power generation under supercritical conditions.

Overview

Newberry Volcano in central Oregon is among the most promising superhot rock geothermal sites in the United States. The project focuses on developing a superhot rock EGS, targeting a young volcanic system, with the potential of producing fluids at temperatures >375°C and for large-scale power production enabled by higher capacity wells. With fewer wells, it is possible to achieve substantially higher power densities and improved thermodynamic efficiencies compared to conventional geothermal systems. Building on more than 40 years of exploration by several research

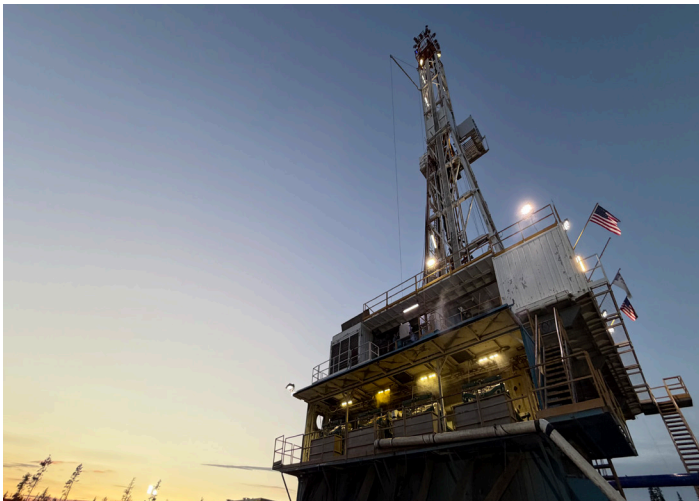
institutions and geothermal companies, Mazama Energy is currently leading the next chapter at Newberry, focusing on the even more ambitious goal of harnessing energy from superhot rock.

As one of the most well-characterized geothermal sites in the United States, Newberry offers exceptional conditions for superhot rock development, with high temperatures accessible at relatively shallow depths. This pilot demonstration will establish a global benchmark addressing subsurface engineering challenges in high-temperature crystalline environments.

The Newberry superhot rock EGS demonstration project is located on the northwestern flank of Newberry Volcano within a 50 km² geothermal lease with superhot rocks at less than 5 km depth and a potential power production estimated at more than 5 GWe. With funding from DOE, Mazama Energy will deliver a first-of-its-kind superhot rock EGS demonstration project in collaboration with state and federal agencies, two universities and three national laboratories, along with engagement with local communities and Tribes.

Site Geology and Reservoir Design

The Newberry Volcano system is defined by a strong conductive thermal anomaly, with measured temperatures reaching about 320°C at depths of approximately 3,000 meters and inferred temperatures above 400°C below 4,000 meters (Cladouhos et al., 2018). The bimodal volcanic composition makes Newberry an exceptional natural laboratory for accessing superhot geothermal resources and advancing next-generation energy systems.



Drilling rig at the Newberry Superhot Rock EGS site in central Oregon, September 26. Source: <https://mazamaenergy.com>

As a first step toward the superhot rock goal, an EGS reservoir was created in 2025 between two 3,000 m deep wells in rocks at 330°C. This pilot demonstration used propping agents and advanced stimulation techniques that build upon conventional hydraulic fracturing principles but incorporate cyclic pressure pulsing to activate and connect natural fractures within the rock (El-Rabaa et al., 2025) to create an engineered reservoir volume in >300°C conditions. The goal of this stimulation sequence is to create a network of complex

fractures that originate from a primary tensile fracture and then propagate through intersecting natural fractures, constituting a hybrid stimulation approach. The design focused on achieving efficient wellbore to reservoir connectivity, initiating and propagating fractures across variable lithologies such as basalt, andesite, and granodiorite, and placing controlled volumes of proppant despite differing mechanical properties. The approach is complemented by other advanced technologies, including the use of crosslinked fracturing fluid systems, sliding sleeves for zonal isolation, and chemical and nano tracers to monitor fluid flow.

Nano tracers offer multiple advantages over conventional chemical tracers, particularly in the challenging high-temperature and high-pressure environment of a hot EGS reservoir. The data from nano tracers can be used to refine 3D numerical models of the reservoir, improving the ability to predict its performance, and optimize energy production. Diagnostic tools were then used to infer the created reservoir volume and inform producer well placement for effective circulation and heat extraction (Grubac et al., 2026).

Distributed acoustic sensing (DAS) and fiber-optic monitoring systems are deployed alongside seismic networks to track microseismicity, characterize stimulated reservoir volume, and ensure safe operational limits during reservoir development.

Key Achievements

- In 2025, Mazama Energy achieved a landmark advancement in geothermal technology by developing the world's hottest EGS at 330°C.
- Successfully deployed novel hybrid reservoir stimulation methods and advanced integrated modeling for system optimization.
- Propped stimulation and diagnostic testing confirmed strong hydraulic connectivity, enabling stable fluid circulation in a superhot crystalline reservoir.
- Peak penetration >100 ft/hr, 2,760 ft bit run through hot volcanic rock with no downhole tool failures.

Lessons Learned

- Creating reliable flow paths in low-permeability superhot rock requires innovative hybrid stimulation techniques.
- Advanced wellbore construction, drilling technologies, and high-temperature-resistant materials are essential for operating under extreme superhot rock conditions.
- The reservoir depends on balancing fluid injection, heat recovery, and induced fracture connectivity.
- Real-time microseismic and reservoir monitoring technologies are key to optimizing stimulation performance and reducing operational risks.
- Integration of multidisciplinary datasets (geology, geophysics, geochemistry, and reservoir engineering) improves reservoir characterization and development planning.
- Early pilot-scale testing is critical to validate numerical models and reduce uncertainty before commercial deployment.

Status and Outlook

The first Newberry demonstration project proves that building an EGS in rocks at temperatures greater than 300°C is no longer theoretical but achievable and scalable by proving controlled stimulation and other integration of advanced technologies.

Now Mazama Energy aims to reach temperatures of 400°C and above to become the first to harness superhot rock geothermal resources. The next major step is the drilling of two horizontal wells and the creation of an EGS reservoir in superhot rocks by the end of 2026. Construction of a commercial-scale 200-MWe power plant will follow, with the goal of delivering the first electrons to the grid before late 2029. The long-term vision for the Newberry site is multi-GWe development projects.

The experience from Newberry's EGS demonstration project, from the early challenges to the recent successes, has provided a wealth of knowledge for the future of superhot rock projects.

The Newberry project provides an important demonstration platform for next-generation superhot geothermal technology. Mazama Energy projects that future superhot-rock systems could deliver 5–10× more power density, using 75% less water and drilling 80% fewer wells than conventional geothermal systems.

The Newberry pilot will serve as a blueprint for developing superhot rock EGS in other geologically suitable locations worldwide, potentially enabling terawatt-scale baseload power.

NEVADA AND UTAH, USA

Case Study 3:

Project Red and Cape Station—From First Pilot to Commercial-Scale EGS

Operator:
Fervo Energy

Partners:
U.S. Department of Energy,
United States Geological
Survey, Utah FORGE,
Stanford University,
Devon Energy,
Turboden

KEY CHARACTERISTICS



FINANCING:
Private and public



EXPERTISE:
Reservoir modeling and tracer testing, induced seismicity mitigation, fiber-optic monitoring, oil and gas industry techniques, horizontal drilling in deep hot rock formations, multistage hydraulic stimulation.



IMPACT:
Demonstrates the first commercially scalable pathway for EGS
Drilling rates improved 143% since the first Cape Station well. Per-foot drilling cost dropped by approximately 70% from Project Red to Cape Station

PROJECT RED



POWER PRODUCTION:
3.0 MW
Production Temperature:
175°C (347°F)
Type of Plant:
Binary-cycle geothermal power plant (closed-loop surface system)
Commercial Off Taker:
Google data centers in Nevada in partnership with NV Energy



ROCK TYPE:
Mixed metasedimentary and igneous formations



TEMPERATURE:
175–237°C
(347–458°F)



DEPTH:
3,641 m (11,946 ft)

CAPE STATION

POWER PRODUCTION:
Phase I ~ 100 MW by early 2027, Phase II adding ~ 400 MW by 2028, with permitting to expand up to 2 GW
Production Temperature:
195°C (383°F)
Type of Plant:
Binary-cycle geothermal power plant (closed-loop surface system)
Commercial Off Taker:
Southern California Edison, Shell Energy, and community choice aggregators

ROCK TYPE:
Granitic Basement

TEMPERATURE:
175–237°C
(347– 460°F)

DEPTH:
3,641 m (11,984 ft)

As two of the most significant next-generation geothermal developments globally, Project Red and Cape Station represent a pivotal transition from pilot-scale EGS demonstrations to commercially scalable deployment. These projects demonstrate the technical and economic viability of applying advanced drilling and reservoir engineering approaches at utility scale. Their success also underscores the broader value of geothermal innovation, particularly through transferable drilling and subsurface characterization technologies that have the potential to accelerate advancement across the wider geothermal industry.

Overview

Project Red (Nevada) and Cape Station (Utah) represent successive stages in the commercialization of EGS. Between 2021 and 2023, Project Red demonstrated for the first time that EGS could move from research into commercial-scale operation by adapting oil and gas techniques. Cape Station builds on that success on a much larger scale and lowers costs by about 67% compared with Project Red.

Project Red marks the first promising advancement of EGS from research to commercial-scale deployment by serving as a learning platform. The project applied horizontal drilling, multi-well pad development, and hydraulic fracturing techniques adapted from the oil and gas industry to create scalable geothermal reservoirs at depths of approximately 2,500 meters. By combining advanced downhole sensing with a closed-loop surface plant, Project Red demonstrated that oil and gas technologies can be repurposed to deliver reliable, 24/7 electricity. Power generated from the project is supplied to the Nevada grid and supports Google data center operations, marking the first corporate agreement to use next-generation geothermal energy for hyperscale computing infrastructure.

Building on Project Red, Fervo began its drilling campaign at Cape Station in June 2023. It is the first large-scale commercial EGS power project in the United States, targeting 500 MW of geothermal power through multi-well horizontal development. The project reflects the shift from demonstration to commercial deployment by applying lessons from earlier wells to reduce costs and scale operations. Its proximity to Utah FORGE, the Blundell Geothermal Power Plant in Utah, existing transmission infrastructure, and extensive subsurface data significantly lowers development risk and supports rapid commercialization.

Technology Transfer: The Oil and Gas Parallel

Fervo's approach demonstrates that geothermal can follow the same cost reduction trajectory as shale gas, where technology transfer, standardization, and learning-by-doing drove a 60%–70% cost decline over a decade. The same dynamic, applied to drilling techniques, well designs, and operational optimization, is now emerging in EGS development.



Advanced geothermal drilling operations.
Source: www.capestation.com

Fervo Energy had drilled more than 25 horizontal wells at its Cape Station development in Utah (as of June 2026), demonstrating major improvements in drilling efficiency and cost reduction. Drilling costs decreased from roughly \$1,050 per foot at Project Red to less than \$450 per foot for the first six wells at Cape Station (El-Sadi et al., 2024). These gains were driven by advances in polycrystalline diamond compact bit technology and the application of physics-based optimization methods to improve mechanical specific energy and sustain higher penetration rates (Akindipe and Witter, 2025).

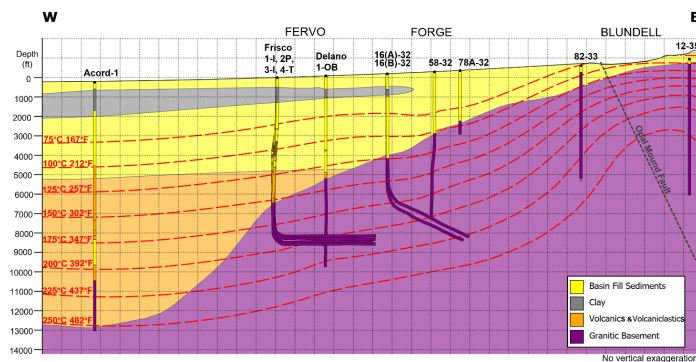
Many of these innovations originated through technology transfer from the oil and gas sector, particularly in horizontal drilling and reservoir development practices. The resulting improvements are expected to accelerate cost reductions and drilling performance across the broader geothermal industry.

Site Geology and Reservoir Design

The Project Red site is located adjacent to the Blue Mountain geothermal field in northern Nevada, within a structurally complex geologic setting. The stratigraphy consists of Miocene to recent basin-fill deposits overlying Mesozoic phyllites, with multiple intrusions of igneous dikes and sills of Mesozoic to Tertiary age. The geothermal system is associated with a displacement transfer zone, where deep fluid circulation is primarily controlled by north-northeast striking normal faults intersected by northwest striking dextral-normal faults. Drilling targeted an area south of the known upflow and outflow zones, where high temperatures are present but natural permeability is limited, making it an ideal location to test EGS concepts.

The project utilized a three-well configuration consisting of a vertical monitoring well, an injection well, and a production well. The injection and production wells form the first commercial-scale horizontal EGS doublet system. Each well includes lateral sections extending approximately 3,250 feet (990 meters), drilled with a 9 7/8-inch hole and completed with 7-inch casing. The laterals were placed at a true vertical depth of approximately 7,700 feet (2,347 meters), reaching maximum reservoir temperatures of around 190–191°C. Horizontal drilling was selected to maximize reservoir contact, improve flow distribution, increase heat exchange surface area, and enhance overall project economics while allowing flexibility across different geologic conditions.

Simulation studies suggest that, in systems such as Project Red, well configuration may play a significant role in reducing water loss. For example, arrangements with a higher producer-to-injector ratio, such as a three-well triplet with two producers flanking a single injector, can be designed to optimize pressure drawdown and lower average reservoir pressure below that of the surrounding boundary pressure (McClure, 2025). Additional strategies, including the use of alternative water sources and advanced surface cooling technologies, are also being actively discussed within the industry.



West-east cross section showing the lateral wells drilled by Fervo, FORGE, and Blundell, with major formation types and measured temperatures. Source: Fercho et al., 2025

Cape Station in Milford Basin, Utah, is targeting hot crystalline granitic basement rock beneath variable volcanic and sedimentary basin fill. The geothermal system is characterized by relatively consistent and well-constrained stratigraphy across the field. Site characterization is supported by an expanding 3D geologic model refined through extensive drilling, logging, and legacy datasets, including nearby FORGE and historical exploration wells. Temperature-depth relationships indicate a high-enthalpy reservoir

(~180–200+ °C in deeper sections), with strong spatial predictability that validates pre-drill basin-scale thermal models.

Structurally, the system is governed by a regional stress regime with a maximum horizontal stress orientation of north-northeast by south-southwest, which interacts with dominant natural fracture sets trending north-northwest by south-southeast. This stress-fracture configuration facilitates hydraulic reactivation of existing fracture networks during stimulation, resulting in predictable fracture growth behavior observed across multiple well pads. Integrated geomechanical and reservoir modeling shows strong agreement between predicted and observed subsurface conditions, demonstrating that Cape Station is a highly predictable EGS environment, where coupled geological, thermal, and structural models can reliably forecast reservoir performance and support scalable geothermal development (Fercho et al., 2025).

Key Achievements

- At Project Red, the stable production temperatures recorded during the first year of commercial operations supported validation of the long-term viability of horizontal-well EGS designs.
- Project Cape demonstrated that horizontal wells can be successfully drilled and completed in high-temperature geothermal environments, while also delivering cost reductions and improved operational efficiency.
- Demonstrated horizontal EGS wells achieved reliable flow rates of 63 liters/second, significantly above previous EGS benchmarks.
- Drilling speeds approximately eight times faster than industry baseline for similar depth geothermal wells, driven by oil and gas techniques.
- Distributed temperature sensing via fiber-optic cable provided continuous reservoir monitoring, enabling real-time optimization.
- Successful reservoir engineering is repeatable and controlled the fracture stimulation, confirming the ability to reliably create engineered geothermal reservoirs in low-permeability hot rock.
- Implementation of DOE-aligned induced seismicity mitigation protocols resulted in no significant seismic events, confirming safe deployment practices.

- Achieved 24/7 power delivery, validating commercial EGS as a firm energy resource.
- Signed a power purchase agreement with Google, demonstrating that EGS power is bankable by commercial buyers.



Geothermal steam testing at a Cape Station facility.
Source: www.capestation.com

Lessons Learned

- **Oil & gas technologies are transferable to geothermal:** Horizontal drilling and multistage stimulation can reliably create engineered geothermal reservoirs in hot dry rock formations.
- **Engineered fracture networks are repeatable and controllable:** Plug-and-perf stimulation enabled predictable reservoir creation with consistent flow distribution along long horizontal laterals.
- **High-performance flow is achievable without natural permeability:** Commercial-scale flow rates were demonstrated in low-permeability rock, significantly expanding geothermal resource potential.
- **Induced seismicity can be effectively managed:** DOE-aligned protocols and traffic light systems allowed safe operations with no significant induced seismic events.
- **Recapture rates are expected to improve over time:** advances in well design, including optimized spacing, multi-well configurations, and improved fracture connectivity, can significantly increase recapture efficiency by shortening fluid return pathways. This also underscores the importance of using lower-value water sources, such as brackish or degraded water, for reservoir pressure maintenance wherever feasible.
- **Real-time fiber-optic sensing improves reservoir control:** Distributed temperature and acoustic sensing provided continuous subsurface data, enabling precise monitoring and optimization of performance.
- **Early thermal breakthrough can be delayed with proper design:** Uniform flow distribution supported stable heat extraction and improved long-term reservoir productivity.
- **Co-location with existing infrastructure reduces cost and risk:** Proximity to existing geothermal facilities enabled faster grid connection and lower development complexity.
- **EGS is scalable with iterative learning:** Each deployment improves drilling efficiency, reservoir design, and overall system performance, accelerating cost reduction over time.
- **Learning curve enables drilling deeper:** Field data has demonstrated a rapid performance learning curve across successive wells, with sustained drilling rates reaching ~70 ft/hour in hard granitic formations, exceeding projected industry benchmarks.
- **Multi-technique reservoir optimization:** Reservoir performance is further optimized through coupled hydraulic fracturing and long-term circulation modeling, incorporating fracture propagation, proppant placement, thermal transport, and geomechanical feedback.

Commercial Scaling Levers

- Standardized well designs and drilling procedures reduce per-well costs with each successive phase.
- Multi-well pad development reduces surface disturbance and equipment mobilization costs.
- Reduced drilling time significantly over successive wells through iterative optimization and learning by doing.
- Long-term power purchase agreements with creditworthy off takers are enabling commercial project financing.
- Secured a first-of-its-kind \$421.4 million non-recourse project finance facility including a \$309 million construction-to-term loan, \$61 million tax credit bridge loan, and a \$51 million letter of credit facility.

Status and Outlook

The Fervo–Google partnership, which began with Project Red in 2023, continues today, allowing Google to add more geothermal power to the Nevada grid while shielding other customers from the project’s costs.

Cape Station is in active development as of 2026, with multiple deep horizontal wells drilled and ongoing reservoir characterization, including refinement of 3D geologic, thermal, and geomechanical models. Early field results from drilling, logging, and stimulation are being used to validate subsurface predictions and optimize subsequent well pads and completion strategies.

Full commercial operation is targeted for the late 2020s. The project is designed as a utility EGS using modular binary cycle surface power plants with organic Rankine cycle systems, enabling scalable, flexible power generation from hot produced fluids. This configuration has the potential to deliver firm, dispatchable 24/7 baseload.

This commercialization pathway builds on the early validation achieved in Project Red, where first-of-a-kind EGS operations delivered 3 MWe grid-connected geothermal power under a collaboration with Google, an early market signal that firm geothermal can scale. If Cape Station performs at full commercial capacity, it would position EGS as a repeatable development model capable of unlocking geothermal resources far beyond conventional hydrothermal basins, creating a viable pathway for dependable power in geologies once considered inaccessible.

ALSACE, FRANCE

Case Study 4:

Soultz-sous-Forêts— A Pioneer in Deep EGS Demonstrations

Operator:
Électricité de Strasbourg (ÉS)
Géothermie

Partners:
Bureau de Recherches Géologiques et
Minières (BRGM), Centre National de
la Recherche Scientifique (CNRS)

KEY CHARACTERISTICS



FINANCING:
Public European R&D



EXPERTISE:
Deep drilling, creating and
enhancing fractures in granitic
basement, deep multi-well
circulation, microseismic
monitoring, long-term
reservoir behavior analysis.



DATA ACCESS:
Open/Public



POWER PRODUCTION:
Total Capacity
1.5 MW
Production Temperature:
160°C (320°F)
Type of Plant:
Organic Rankine
cycle binary



ROCK TYPE:
Granite/
monzogranite



TEMPERATURE:
180–200°C
(356–392°F)



DEPTH:
2,000–5,000 m
(6,561–16,404 ft)

The Soultz-sous-Forêts geothermal project is an early EGS demonstration that helped prove EGS technology. It showed that electricity can be generated from deep, hot, low-permeability granite by drilling several kilometers underground, stimulating fractures, and circulating water through an engineered reservoir. Developed over decades as a European research pilot project, Soultz helped establish the scientific and technical foundation for modern EGS through its work on deep drilling, reservoir stimulation, binary-cycle power generation, tracer testing, brine chemistry, and induced seismicity monitoring. Although its power output has been small, it proved core EGS concepts and provided a benchmark dataset that has informed geothermal research, project design, and risk management far beyond France.

Overview

The Soultz-sous-Forêts project is a landmark in demonstrating electricity production from EGS in low-permeability crystalline rock outside volcanic settings. Initiated in the late 1980s and producing power since 2008, the project shows that geothermal energy can be harnessed by enhancing natural fracture systems in granitic basement rock, opening opportunities for geothermal development closer to demand centers. Soultz achieved first electricity production around 2008 with a binary plant (~1.5 MWe) and has served as a long-term R&D platform for deep geothermal technologies.

Extensive prior hydrocarbon exploration provided an unusually adequate subsurface dataset for the site's later geothermal development (Dezayes et al., 2010). Multiple deep wells (e.g., GPK1–GPK4) were drilled to approximately 5,000 m, with staged stimulations between 1993 and 2005 at depths from about 3,600 to 5,000 m, followed by circulation experiments to balance injection and production. The Soultz EGS can be described as a fractured reservoir connecting different wells along flow channels generated by the main hydraulic pathways (Egert et al., 2020).

A binary power plant began operation in 2008 supported by Energie Baden-Württemberg EnBW and Électricité de Strasbourg Géothermie. After years of R&D, major surface facilities and the power unit were retrofitted in 2016 to support ongoing and future commercial operations.

Site Geology and Reservoir Design

The site lies in an extensional basin with sedimentary formations stratigraphically overlaying granitic basement; the engineered reservoir is in hydrothermally altered, naturally fractured granite at roughly 4.5–5 km depth with temperatures ~180–200°C. The overlying sedimentary section shows an anomalously high geothermal gradient, locally reaching ~11°C/100 m, corresponding to a regional heat flow of roughly 100–120 mW/m², about twice the Central European average (Pribnow & Schellschmidt, 2000; Rummel, 1991). Between roughly 1,000 and 3,500 m depth, the apparent gradient decreases sharply due to a natural brine convection system near the sediment–basement interface; at greater depth in the granite, the conductive gradient returns to more typical values of about 3°C/100 m (Pribnow & Schellschmidt, 2000; Dezayes et al., 2010).

The reservoir consists of fractured granitic basement at approximately 4.5–5 km depth beneath a sedimentary cover sequence (Gérard et al., 2006; Dezayes et al., 2010). Temperatures in the stimulated zones are typically about 180–200°C (Gérard et al., 2006; Evans et al., 2012), and formation fluids are highly saline brines containing dissolved gases and metals that contribute to scaling and corrosion challenges in production and surface equipment (Sanjuan et al., 2010; Pauwels et al., 1993). The deep system is developed with a tri-well configuration, commonly referred to as GPK-2, the production well, and GPK-3 and GPK-4 used as injection wells, using deviated wells aimed at different fracture sets to improve hydraulic connectivity while limiting rapid thermal short-circuiting (Gérard et al., 2006; Baria et al., 2004). Surface facilities use a binary organic Rankine cycle plant, with heat exchangers, materials selection, and chemical treatment designed to manage brine salinity and scaling tendencies (DiPippo, 2012; Sanjuan et al., 2016). The reservoir also shows strong permeability contrasts, with major fault or shear zones reaching around 10⁻¹¹ m², whereas intact or strongly altered granite matrix permeability is typically on the order of 10⁻¹⁶ to 10⁻¹⁷ m² (Sausse et al., 2010; Ledésert et al., 2010).

A comprehensive monitoring program, including downhole and surface microseismic networks, pressure and flow transient analysis, tracer tests for inter-well connectivity, and thermal and geochemical surveillance, was used to guide well placement, stimulation design, and subsequent operations (Baria et al., 2004; Dezayes et al., 2005; Sanjuan et al., 2010).

Stimulation at Soultz has centered on hydraulic shearing of pre-existing fractures through high-rate water injection to enhance permeability and injectivity without relying on proppants (Baria et al., 1999; Evans et al., 2005). Chemical stimulation, including acidizing treatments with hydrochloric or hydrofluoric acid-based mixtures and inhibitors, has been used to dissolve near-wellbore alteration products and precipitates and to improve flow performance, both during initial development and later maintenance campaigns (Nami et al., 2008; Portier et al., 2009). Operators applied staged and zonal stimulations, together with careful pressure management, to target discrete fracture zones while reducing induced seismicity risk (Evans et al., 2012; Häring et al., 2008).

Following the 2005 circulation test and later improvements in the hydraulic performance of the three deep wells, a decision was made to construct a 1.5-MWe geothermal power plant (Genter et al., 2010).



Geothermal power plant of Soultz-sous-Forêts, in the background Alsace town. Source: ES

Key Achievements

- The first sustained EGS electricity production from a deep fractured granite reservoir, demonstrating that multi-well circulation at ~5 km depth can yield usable wellhead conditions for binary conversion.
- The project advanced integrated reservoir characterization methods, linking microseismic imaging, hydraulic responses, and tracer analysis, that have since been widely adopted in other Upper Rhine Graben and international EGS projects.
- Soultz demonstrated sustained circulation and power generation from deep granite, validated microseismic monitoring to map stimulated volumes, and advanced tracer testing to quantify connectivity. It delivered practical methods for stimulation design, well architecture, and surface-plant operation, plus corrosion/scale control strategies, informing subsequent Rhine Graben projects.
- Soultz contributed significantly to understanding brine chemistry, materials selection (e.g., mild steels, stainless steels, nickel alloys, and titanium grade 2) (Mundhenk et al., 2013; 2014), and chemical management for saline, metal-rich geothermal fluids, helping mitigate corrosion and scaling in geothermal operations (Aquilina, Brach, and Pauwels, 1997).
- The experience gained at Soultz informed later Upper Rhine Graben projects and contributed to evolving approaches for stimulation, induced seismicity management, and reservoir monitoring (Gérard et al., 2006; Evans et al., 2012).

Lessons Learned

- Reservoir permeability can be improved effectively by hydraulically shearing existing fractures with high-rate water injection, while chemical stimulation supports restoring or enhancing near-wellbore flow. Staged, zone-specific treatments and careful pressure control are essential to improve performance and limit induced seismicity.
- Induced seismicity management is central to EGS operations; careful control of injection pressures and rates, staged stimulations, and traffic-light protocols are essential to limit felt events.
- Creating large, stimulated volumes alone is insufficient: flow paths must provide adequate thermal sweep between injector and producers, and tracer testing is essential to diagnose and address short-circuiting that can lead to early thermal breakthrough.
- Geochemical challenges, especially scaling (silica, carbonates, sulfates) and corrosion, require robust chemical treatment programs, testing suitable materials, and tailored heat-exchanger design.
- Sustained production was achieved through periodic re-stimulation and targeted chemical/mechanical interventions that maintained injectivity and productivity, while reliable small-scale plant operation highlighted the value of high-capacity factors and beneficial heat offtake for strengthening project economics.

Status and Outlook



Geothermal power plant of Soultz-sous-Forêts. Source : ES

The Soultz plant continues to operate as a small-scale EGS demonstration with phases of testing, optimization, and maintenance aimed at stabilizing circulation and improving reliability.

Future work focuses on optimizing reservoir management, reducing seismic risk, improving flow and thermal recovery, and expanding knowledge transfer to regional heat and power projects in the Upper Rhine Graben.

Ongoing research efforts focus on exploring operational strategies that improve thermal sweep and capacity factors, via initiatives such as MEET (Multidisciplinary and multi-context demonstration of EGS exploration and Exploitation Techniques and potentials).

In January 2023, Électricité de Strasbourg (ÉS) and Eramet established an exclusive partnership under a Memorandum of Understanding (MoU) to develop the Alsace Géothermie Lithium (Ageli) project. The technical objective of this initiative is the industrial-scale extraction and refining of lithium from geothermal brines located within the Alsace region including the Soultz plant. The Ageli project is engineered to achieve a commercial-scale production capacity of at least 10,000 tonnes of lithium carbonate equivalent (LCE) per annum by 2030.

UTAH, USA

Case Study 5:

Utah FORGE – Frontier Observatory for Research in Geothermal Energy

Sponsor:

U. S. Department of Energy

Lead:

Energy and Geoscience
Institute, University
of Utah

KEY CHARACTERISTICS

**FINANCING:**

Public and private, including cost share total funding of \$328 M.

**EXPERTISE:**

EGS, unconventional systems, drilling and well construction technologies, rock mechanics, reservoir engineering, hydraulic stimulation, induced seismicity, and seismic monitoring.

**DATA ACCESS:**

Open/Public, over 133 terabytes of free data.

**CRITICAL RESEARCH:**

Stimulation planning and design, fracture network characterization and control, reservoir management and productivity, induced seismicity monitoring and mitigation.

**TARGET IMPACT:**

Strengthens understanding of key mechanisms controlling EGS success.

**ROCK TYPE:**

Granitic and metamorphic crystalline rocks.

**TEMPERATURE:**175–225°C
(347–437°F)**DEPTH:**2,000–3,300 m
(6,561–10,826 ft)

Utah FORGE is a dedicated underground laboratory focusing on developing, testing, and de-risking innovative tools and stimulation techniques for creating EGS reservoirs. The project advances technologies originally pioneered in oil and gas to enable reliable electricity generation from hot crystalline rocks. By demonstrating solutions with broad applicability, Utah FORGE helps validate the feasibility, safety, and scalability of large-scale geothermal development. In parallel, Utah FORGE supports scientists, engineers, and students through research funding, building the expertise and evidence base needed to expand future energy security and expand access to geothermal energy.

Overview

Utah FORGE is a dedicated laboratory for developing, testing, and accelerating breakthroughs in EGS technologies to advance the use of geothermal resources. Includes multiple deep wells reaching depths of approximately 2.0–3.3 km within hot crystalline basement rocks composed primarily of granitic and metamorphic lithologies. Reservoir temperatures range from approximately 175° to 225°C.

The site comprises deep vertical monitoring wells, and deep deviated injection and production wells, as well as shallow seismic observation wells. Together, these wells have enabled high-resolution subsurface characterization and provide the infrastructure for advancing and validating EGS technologies.

In 2018, the U.S. Department of Energy formally selected a site near Milford, Utah, for the FORGE initiative, funding it up to \$140 million. The FORGE initiative has progressed through four phases:

- **Phase 1 (2015–2016)** involved five teams—Fallon (Nevada), Newberry Volcano (Oregon), Snake River Plain (Idaho), Milford (Utah), and West Flank (California)—that evaluated the potential of their proposed sites, developed R&D and data-collection plans for Phase 2, and compiled available site characterization data into geologic models.
- **Phase 2 (2016–2018)** down-selected teams down to two, the Fallon FORGE team and the Utah FORGE team. Those teams fully instrumented, characterized, and permitted their candidate sites for drilling and full-scale operations in preparation for Phase 3 R&D. Each team drilled a pilot well.
- **Phase 3 (2018–2024)** centers on the Utah FORGE team at the FORGE site in Milford, Utah, drilling full-scale wells and implementing a collaborative, solicitation-driven R&D program in which partners from industry, academia, and national laboratories were provided opportunities to conduct relevant research at the site.
- **Phase 4 (2024–2028)** circulation test to determine the longevity of an EGS reservoir for commercial electricity generation, drill 16C an instrumented well, conduct long-term flow test and evaluate temperatures declines.



Drill rig operations at the Utah FORGE field laboratory in Milford, Utah at sunset. Source: Dr. Clay Jones

Utah FORGE has identified the following critical research areas:

- **Stimulation Design and Methodology:** Research focused on optimizing well design and stimulation strategies based on geological, geochemical, and reservoir characteristics.
- **Fracture Network Characterization and Control:** Research aimed at improving understanding of existing fracture network systems and development during reservoir stimulation.
- **Reservoir Management:** Research focused on maintaining long-term reservoir performance, thermal production, and efficient heat extraction.



Drilling operations at the Utah FORGE field laboratory, showcasing advanced downhole tools and well construction technologies. Source: Flash Point

Its capabilities include drilling and reservoir stimulation testing, subsurface monitoring, numerical simulation and reservoir modeling, integrated 3D earth models, seismic monitoring, and publicly available geoscience datasets that support research on fracture network development in crystalline basement rocks.

Utah FORGE features comprehensive instrumentation and real-time data acquisition and sharing systems that provide continuous documentation of field activities and subsurface operations. Its cutting-edge research, paired with an equally advanced collaboration and management platform, makes it a first-of-its-kind initiative.

While no FORGE-specific permitting delays are publicly documented, permitting complexity remains a broader barrier across geothermal development generally, including lengthy federal environmental reviews and, at times, delayed authorizations on already-approved leases (Curtis, 2024). Federal action has recently begun to address this: in April 2024, the Bureau of Land Management adopted new National Environmental Policy Act categorical exclusions for geothermal exploration activities across roughly 245 million acres in 12 western states, eliminating environmental assessments for exploration-phase permits (BLM, 2024).

Key Technical Achievements

- Demonstrated hydraulic connectivity between injection and production wells, validating the fundamental EGS concept in crystalline basement rocks.
- Demonstrated the use of polycrystalline diamond compact drill bits and disciplined evaluation of drilling data in real-time, significantly increasing drilling rates of penetration, from 440 hours to 60 hours at an equivalent depth of 6,000 feet.
- Advanced the use of distributed fiber-optic sensing technologies (DAS/DTS/DSS) for real-time monitoring of underground temperature, fluid movement, strain, and microseismic activity in hot geothermal environments.
- Demonstrated multi-zone stimulation of high-temperature crystalline rock using conventional zonal isolation technologies.
- Effectively drilled highly deviated wells in crystalline rocks under temperatures exceeding 200°C, expanding the operational envelope for EGS well construction.
- Successfully stimulated both injection and production wells, demonstrating the ability to stimulate through casing in high-temperature wells. A subsequent 9-hour circulation test demonstrated sustained fluid flow and thermal energy transfer through an EGS reservoir in hot, dry crystalline rock, representing a major milestone for industry. This was followed by a 30-day circulation test achieving commercial-scale results.
- Developed, integrated, and field validated advanced coupled geomechanical, thermal, and reservoir simulation models in collaboration with national laboratories and university partners.
- Published technical datasets through the Geothermal Data Repository (GDR), providing open access to drilling, stimulation, monitoring, and reservoir performance data.
- Produced more than 90 technical publications, peer-reviewed journals and conference proceedings.

Strategic R&D Partnerships

The project brings together a coordinated network of national laboratories, academic institutions, industry partners, and government agencies to support end-to-end geothermal development of EGS technologies.



Aerial view of the Utah FORGE field laboratory, showing the layout of production, injection, and monitoring wells across the test site. Source: SLC

National laboratories provide advanced capabilities in subsurface modeling, geophysics, reservoir characterization, energy systems analysis, material sciences, and experimental validation:

- Idaho National Laboratory
- Lawrence Berkeley National Laboratory
- Lawrence Livermore National Laboratory
- Los Alamos National Laboratory
- National Laboratory of the Rockies
- Pacific Northwest National Laboratory
- Sandia National Laboratories.

Academic partners contribute to foundational research, data analysis, field experimentation, numerical modeling, workforce developing, and innovation in geothermal science and engineering:

- California State University, Long Beach
- Clemson University
- Colorado School of Mines
- Northwestern University

- Oklahoma State University
- Pennsylvania State University
- Purdue University
- Rice University
- Stanford University
- Texas Tech University
- University of California, Berkeley
- University of Hawai‘i
- University of Illinois at Urbana-Champaign
- University of New Mexico
- University of Oklahoma
- University of Pittsburgh
- University of Texas at Austin
- University of Utah (lead academic institution)
- University of Wisconsin-Madison.

Industry partners support field implementation, drilling and stimulation operations, reservoir monitoring, subsurface imaging, software solutions, environmental services, and technology deployment:

- Array Information Technology
- Baker Hughes
- Class IV Solutions
- Fervo Energy
- Global Technology Connection Inc.
- Halliburton
- Jarpe Data Solutions Inc.
- KSWC Engineering and Machining
- Liberty Oilfield
- MTS Systems
- PetroQuip Energy Services LLC
- Schlumberger
- Silixa LLC
- Tejas Research and Engineering, LLC
- Welltech.

Government, land management, and utility partners support permitting, land access, regulatory compliance, and infrastructure integration:

- Beaver County
- U.S. Bureau of Land Management
- U.S. Geological Survey
- Utah State Trust Lands Administration
- Utah Governor’s Office of Energy Development
- Utah Division of Natural Resources.

Lessons Learned and Outlook

Utah FORGE research has demonstrated and informed technology development across the geothermal industry, including leader companies such as Fervo Energy.



Drilling rig at the Utah FORGE field laboratory in Utah, supporting deep drilling and reservoir stimulation. Source: Eric Larson

The open-data approach has proven valuable for accelerating technology development by reducing duplication of effort and enabling broader collaboration across industry, academia, and government.

Public investment in early-stage, high-risk research can reduce technical uncertainty and help attract private-sector investment during later stages of project development.

The FORGE initiative is a critical enabler for DOE to reduce EGS cost by advancing technologies and best practices that de-risk development and pave the way for commercial deployment.

The FORGE model, a dedicated, publicly funded EGS field laboratory that generates open-access data, provides a replicable framework for GeoFuture Initiative countries seeking to de-risk next-generation geothermal development.

Establishing similar facilities in volcanic, sedimentary, or other geological settings would expand the applicability of research outcomes and provide insights relevant to a much wider range of geothermal resources worldwide.

USULUTÁN, EL SALVADOR

Case Study 6:

Berlin Geothermal Plant—
Binary Cycle with Stimulated
Reservoir ActivitiesOperator:
LaGeo S.A. de C.V.Partners:
World Bank

KEY CHARACTERISTICS

**FINANCING:**

Public utility investment (CEL/
LaGeo National Energy Program)
Government of El Salvador
energy infrastructure funding.

**EXPERTISE:**

Reinjection optimization (thermal
and pressure balancing) and
reservoir pressure management;
well stimulation through acidizing
and scale-removal treatments;
production zone management to
minimize thermal breakthrough;
reservoir monitoring and numerical
reservoir modeling.

**IMPACT:**

One of the largest geothermal
producers in Central America
and a major contributor to El
Salvador's geothermal electricity
generation. Geothermal energy
supplies approximately 20% of
the country's electricity mix.

**POWER PRODUCTION:**

Installed Capacity:
116 MWe

**Type of Plant
Configuration:**
Multiple flash steam units +
binary bottoming cycle
(~7–8 MW additional
systems in recent
upgrades); Long-term
operation with stage field
expansion since the 1990s.

**ROCK TYPE:**

Fractured volcanic
hydrothermal
reservoir (liquid-
dominated system),
deep fractured
volcanic intrusive
basement.

**TEMPERATURE:**

270–310°C
(518–590°F)

**DEPTH:**

1,900–3,000 m
(6,234–9,843 ft)

The Berlin geothermal plant in El Salvador is operated by LaGeo, the country's state-owned geothermal energy company and a subsidiary of CEL (Comisión Ejecutiva Hidroeléctrica del Río Lempa). El Salvador has one of the world's highest shares of geothermal power in its national electricity mix, approximately 20%, and the Berlin field is central to this achievement. Geothermal exploration in El Salvador began in the 1960s, with the first exploratory well drilled at the Ahuachapán geothermal field in 1968. Following successful power production, more wells were drilled, with power production beginning in 1980. The Berlin geothermal field began operations in the 1990s and was later expanded through the addition of multiple single-flash units and a binary cycle power plant. Today, Berlin and Ahuachapán are the country's principal operating geothermal fields, while exploration and development activities continue at the San Vicente and Chinameca prospects.

Overview

The Berlin geothermal complex is located near the municipality of Berlín in the department of Usulután, about 100 km east of San Salvador, within the Tecapa volcanic region. It is one of El Salvador's two operating geothermal fields and a major contributor to the country's electricity supply. The geothermal reservoir is hosted within volcanic rocks, including andesites, ignimbrites, and pyroclastic deposits, and is characterized by high-temperature fluids ranging from approximately 270–310°C. Extensive geological, geochemical, and geophysical investigations were conducted to characterize the resource and guide field development.

The Berlin geothermal complex primarily consists of flash-steam generating units and has undergone multiple expansions since commercial operations began in the 1990s. To improve energy recovery and overall efficiency, LaGeo incorporated binary cycle technology based on an organic Rankine cycle system that utilizes residual heat from geothermal fluids that would otherwise remain unused. Because the binary system operates as a closed-loop process, geothermal fluids can be fully reinjected into the reservoir, supporting long-term reservoir sustainability (Ormat, 2019). The field currently has an installed capacity of approximately 116 MWe and is supported by about 40 wells, including production, reinjection, and monitoring wells.



Surface facilities at the Berlin Geothermal Power Station, illustrating the heat exchange and steam separation infrastructure. Source: LaGeo

In 2025, El Salvador inaugurated the Berlin 2 binary-cycle expansion, adding approximately 7.5 MW of generation capacity through the utilization of residual geothermal heat. The project represented the first geothermal power plant in the country since 2007 and demonstrated the potential for increasing electricity generation through improved utilization of existing geothermal resources. The expansion required an investment of approximately \$37 million and contributed to El Salvador's broader strategy of expanding renewable energy production while maintaining high levels of geothermal generation (ThinkGeo, 2025).

Site Geology and Reservoir Design

The injection well TR-1A initially exhibited a stable injection rate of approximately 30 kg/s (Montalvo et al., 2005). The well's primary permeable zone occurs below a depth of approximately 2,000 m depth, and samples of amorphous silica were identified near 2,300 m depth. After more than 2 years of reinjection operations, the injection rate declined drastically to around 20 kg/s. To restore well performance, a chemical stimulation treatment pre-flush followed by an acid mixture designed to dissolve mineral deposits and improve permeability near the wellbore was conducted in October 2001 (Barrios et al., 2007). Following treatment, injectivity was restored to nearly its original capacity, demonstrating the effectiveness of chemical stimulation for maintaining reinjection performance in high-temperature geothermal reservoirs.

Key Achievements

- El Salvador demonstrates that geothermal energy can achieve a substantial share of national electricity generation when supported by long-term investment, resource development, and consistent energy policies.
- Chemical mitigation and reinjection management, have helped maintain and improve productivity in wells experiencing natural decline.
- Binary cycle plants can be deployed as modular additions to existing geothermal fields, enabling electricity generation from lower-enthalpy geothermal fluids and residual heat streams.
- Residual geothermal heat from the Berlin facility is utilized for direct-use applications, including greenhouse cultivation, irrigation using geothermal condensate, and fruit dehydration projects.

- The geothermal field includes a wildlife protection park (111,842 m²) and has initiated several reforestation projects.
- LaGeo has implemented programs to support women's participation in the geothermal sector and surrounding communities. Women represent approximately 30% of the workforce at the Berlin plant and receive training in environmental conservation, animal health care, forest protection, and English language skills.

Status and Outlook

El Salvador has abundant geothermal resources and limited domestic fossil energy resources, making geothermal energy a strategically important component of the country's energy security and economic development.



Berlin Geothermal Power Station, illustrating surface infrastructure. Source: LaGeo

Binary cycle technology growth is particularly relevant for CEM partner countries because it expands the range of geothermal resources that can be economically utilized. By generating electricity from moderate-temperature geothermal fluids and residual heat streams, binary systems can improve resource recovery and increase power output from existing fields.



Berlin Geothermal Power Station. Source: LaGeo

The Berlin experience demonstrates how integrating binary cycle technology into mature geothermal operations can enhance efficiency, extend resource utilization, and support long-term baseload energy development.

El Salvador is actively working on new geothermal projects that represent a new wave of energy development for the country.



Berlin Geothermal Power Station. Source: LaGeo

HENGILL, ICELAND

Case Study 7:

Hellisheidi (Hellisheiði)— One of the World's Largest Geothermal Combined Heat and Power Plants

Operator:
ON Power, Reykjavik Energy

Partners:
University of Iceland,
CarbFix

KEY CHARACTERISTICS

**FINANCING:**

Public utility investment through ON Power and Reykjavik Energy, supplemented by national and international research funding for gas mineralization and geothermal innovation projects.

**EXPERTISE:**

Combined heat and power (CHP), reservoir management, geothermal fluid reinjection, geochemical monitoring.

**IMPACT:**

One of the world's most technically advanced geothermal power plants, integrating gas reinjection and mineralization for efficient, reliable operations.

**POWER PRODUCTION:**

Installed Capacity:
303 MWe and 200 MWth thermal output

Type of Plant Configuration:
Double-flash steam turbines and CHP facility with district heating integration.

**ROCK TYPE:**

Fracture-controlled basaltic and hyaloclastite, flow dominated by fractures along active faults.

**TEMPERATURE:**

250–300°C
(482–572°F)

**DEPTH:**

1,500–3,000 m
(4,900–9,800 ft)

Hellisheidi is one of the world's largest combined heat and power geothermal plant, with an installed capacity of approximately 303 MWe of electricity and 200 MWth of thermal energy supplied to the Reykjavik district heating network. Beyond power generation, the facility serves as a research platform for next-generation geothermal technologies, including advanced reservoir monitoring, reinjection optimization, and geothermal fluid management. Hellisheidi is also home to the pioneering CarbFix project, the world's most advanced commercial-scale geothermal gas mineralization initiative, which permanently stores geothermal gases by converting them into stable carbonate minerals within basaltic formations.

Overview

The Hellisheidi power station, located in southwestern Iceland within the Hengill volcanic complex, has been operating since 2006 and is one of the world's largest geothermal combined heat and power (CHP) facility (Karlsdottir et al., 2020). Reservoir temperatures generally range from 250–300°C (482–572°F), with localized zones exceeding 300°C (572°F). The facility utilizes a double-flash CHP system in which high-pressure

turbines generate electricity from separated steam, while low-pressure turbines recover additional energy from flashed brine, and residual heat supports district heating in the Reykjavik area. This cascaded use of the geothermal fluid allows for a more efficient use of the resource than in most other geothermal power plants (Karlsdottir et al., 2020).

Reinjection of brine and condensate maintains reservoir pressure, mitigates thermal breakthrough, and enables sustainable long-term operation. Integration with the CarbFix program permanently stores CO₂ and H₂S in basalt, where the gases mineralize within months to year (Stefánsson et al., 2011).



Hellisheidi Geothermal Power Station Landscape. Source: ON Power

Site Geology and Reservoir Design

The geothermal reservoir is hosted within fractured basaltic rocks, where permeability is controlled by active faults and interconnected fracture networks that facilitate the circulation of high-temperature geothermal fluids (Stefánsson et al., 2011).

Reservoir management at Hellisheidi relies heavily on reinjection and pressure support to sustain long-term production from the high-temperature basaltic geothermal system. Prior to full-scale field development, stimulation activities were conducted in the deep exploration well HE-8 in 2003 to improve injectivity and evaluate reservoir permeability at depths of approximately 2.8 km (Bjornsson, 2004).

The primary stimulation method involved controlled cold-water injection immediately after drilling and again following approximately three months of thermal recovery. This thermal stimulation aimed to induce contraction of the hot basaltic rock surrounding the wellbore, promoting fracture opening and improving hydraulic connectivity to permeable feed zones. Unlike conventional hydraulic fracturing, the process relied primarily on thermal stress-induced fracture enhancement rather than high-pressure fluid injection to create new fractures.

Results from the single diagnostics test, HE-8 stimulation, demonstrated that cold-water injection could function as both a reservoir enhancement technique and a diagnostic tool for evaluating fracture connectivity, permeability distribution, and the feasibility of deep geothermal resource development in basaltic systems such as Hellisheidi (Bjornsson, 2004). The experience gained from these stimulation activities contributed to the understanding of deep geothermal reservoir behavior in the Hengill volcanic system and informed reservoir management strategies used to support long-term geothermal production.

Key Achievements

Hellisheidi Power Station is an extremely efficient producer of geothermal energy. Notable achievements include:

- **Large-scale CHP operation:** Integration of ~303 MWe electricity and 200 MWth of thermal energy supplied to the Reykjavík district heating network, making Hellisheidi the world's largest CHP facility (Karlsdottir et al., 2020).
- **High-efficiency energy conversion:** Implementation of a double-flash geothermal system that maximizes steam utilization and overall energy recovery from high-temperature geothermal fluids (Karlsdottir et al., 2020).
- **Gas mineralization leadership:** Development of the CarbFix project, which captures gases from geothermal operations and permanently stores them through rapid mineralization in basaltic formations (Karlsdottir et al., 2020).
- Innovative and integrated gas capture, reinjection, and mineralization technologies (Stefánsson et al., 2011).



Wellhead and steam gathering infrastructure at the Hellisheiði Geothermal Power Station. Source: ON Power

Lessons Learned

- **Commercial operations can accelerate geothermal innovation:** Hellisheiði successfully combines large-scale geothermal energy production with applied research, using operational data to improve reservoir management, validate emerging technologies, and advance geothermal development.
- **Reinjection is essential but requires careful management:** Reinjection at the Gráhnúkar (2007) and Húsmúli (2011) sectors has helped maintain reservoir pressure and support long-term production. However, increased pore pressure associated with reinjection also induced localized seismicity, including two magnitude events near Húsmúli in 2011, M3.9 and M4.0, October 2011. These events were linked to the reactivation of pre-existing faults (Juncu et al., 2020).
- **Fracture-controlled flow governs reservoir performance:** Fluid circulation and permeability within the Hengill geothermal system are strongly controlled by fault and fracture networks. Understanding these structures is critical for well placement, production optimization, and reinjection planning (Stefánsson et al., 2011).
- **Comprehensive monitoring supports long-term operations:** Continuous monitoring of pressure, microseismicity, ground deformation, and reservoir response are essential for managing geothermal resources safely and effectively. At Hellisheiði, the South Iceland Lowland seismic network, together with GPS and Interferometric Synthetic Aperture Radar (InSAR) observations, has enabled detailed tracking of fault activation, subsidence (approximately 2 cm/yr), and pressure propagation associated with production and reinjection activities (Juncu et al., 2020).

- **Cascaded CHP systems maximize resource utilization:** Sequential use of geothermal fluids for electricity generation and district heating significantly improves overall energy recovery and efficiency from high-enthalpy geothermal resources (Karlsdóttir et al., 2020).
- **Commercial-scale opportunity:** The CarbFix project demonstrates that permanent mineralization of produced gases can be successfully integrated into large-scale geothermal operations (Karlsdóttir et al., 2020).
- **Advancement of next-generation geothermal technologies:** Demonstration of reservoir stimulation, reinjection optimization, geochemical monitoring, and gas mineralization approaches that provide valuable lessons for future EGS, superhot rock, and next-generation geothermal developments.



Surface facilities at the Hellisheiði Geothermal Power Station, illustrating the heat exchange and steam separation infrastructure. Source: ON Power

Status and Outlook

Hellisheiði has ongoing efforts focused on optimizing reinjection strategies, improving reservoir monitoring and numerical modeling, and expanding advanced gas mineralization through the CarbFix project. The experience gained in reservoir management, induced seismicity mitigation, CHP operations, and gas mineralization provides valuable insights for the next-generation geothermal developments. Supported by decades of public investment and a strong culture of research and innovation, Hellisheiði demonstrates how integrated energy production, district heating, and gas management can enhance the long-term efficiency and scalability of geothermal resources worldwide. Reservoir stimulation is not part of current operations for the Hellisheiði plant.

LEYTE, PHILIPPINES

Case Study 8:

Leyte—Hydrothermal System in the Philippines with Build-Operate-Transfer Development Structure

Operator:
Energy Development Corporation

Partners:
First Gen Corp,
Department of Environment and Natural Resources

KEY CHARACTERISTICS



FINANCING:
Build-operate-transfer



EXPERTISE:
Multi-well stimulation



IMPACT:
Third largest geothermal producer globally



POWER PRODUCTION:
Total Capacity
700 MW
Type of Plant:
Multiple dry steam and binary



ROCK TYPE:
Andesitic-dacitic lavas, breccias, and pyroclastics, with hydrothermal fluids heated by young magmatic intrusions.



TEMPERATURE:
240–300°C
(464–572°F)



DEPTH:
1,000–3,000 m
(3,280–9,843 ft)

The Leyte geothermal fields in the Eastern Visayas region of the Philippines represent one of the largest concentrations of geothermal power in Southeast Asia. The Philippines is the world's third-largest geothermal producer, and the Leyte fields, including Tongonan and Southern Leyte, have been central to this achievement. Completed in 1983, this large-scale geothermal complex produces >600 MWe from a high-temperature, fracture-controlled hydrothermal system along the Philippine Fault.

Overview

The Leyte Geothermal Production Field (commonly Tongonan/Leyte) is located on Leyte Island in the Eastern Visayas, primarily within the municipalities of Kananga and Ormoc. It is developed and operated by Energy Development Corporation (EDC), with power plants historically built by the National Power Corporation and later privatized. Since 1979, EDC has drilled approximately 233 wells. Cumulative gross generation reported by Fronda et al. (2021) is about 21,242.64 GWh for Tongonan I (since 1977) and 79,322.34 GWh for Unified Leyte.

Commercial generation began in the 1980s at Tongonan-1. Expansions through the 1990s created the Leyte Geothermal Power Complex, the largest

geothermal development in the Philippines. The complex includes multiple plants: Tongonan (108 MW), Upper Mahiao (125 MW), Malitbog (232.5 MW), and Mahanagdong A and B (180 MW combined), with additional optimization/binary units utilizing separated brine. Total installed capacity in Leyte is on the order of 700+ MW; actual output varies with reservoir conditions, maintenance, and market dispatch.

Over decades of operation, EDC has sustained generation through make-up drilling, reservoir monitoring (pressure, temperature, chemistry, microseismic), and environmental management. The Leyte complex supplies baseload power to the Visayas grid.

Site Geology and Reservoir Design

The resource is a high-temperature, liquid-dominated system associated with Quaternary arc volcanism and major structures of the Philippine Fault zone. The reservoir is hosted in andesitic-dacitic lavas, breccias, and pyroclastics, with heat supplied by young magmatic intrusions beneath the Tongonan dome and adjacent sectors (Upper Mahiao, Malitbog, Mahanagdong).

Permeability is strongly fault- and fracture-controlled, governed by the strike-slip Philippine Fault and associated splays, which define key upflow and production zones (Lagmay et al., 2003). Operational strategies have been refined to sustain steam supply across sectors, including:

- Large-scale steamline interconnection (“steam highway”) to balance supply between fields
- Relocation of reinjection to minimize thermal breakthrough and short-circuiting
- Conversion of select injection wells to production where appropriate
- Targeted drilling of deeper make-up wells in less-depleted areas (Gonzalez et al., 2005).

Long-term production has induced pressure drawdown, lateral/vertical steam-zone expansion, and fluid migration from peripheral areas. Integrated monitoring, geochemical analyses, pressure/temperature measurements, and repeat microgravity tracks mass changes, recharge, and fluid movement. Studies indicate significant net mass loss with limited natural recharge, underscoring the need for sustained reinjection and adaptive management (Apuada et al., 2005).

The field’s proximity to the Philippine Fault necessitates geomechanical awareness. A magnitude 6.5 earthquake occurred within the area in 2017; analyses highlight the importance of integrating reservoir and seismic monitoring to understand interactions between fluid extraction/reinjection and fault behavior.

Targeted well interventions have enhanced performance. For example, matrix acid stimulation of three mud-damaged injection wells (MG-7RD, 4R7D, 4R12D) restored injectivity and capacity using diagnostics (pressure transient analysis) and staged hydrochloric/hydrofluoric acid treatments with diversion, where applicable. Injectivity indices and capacities increased substantially, and near-wellbore skin was markedly reduced, demonstrating the effectiveness of diagnostics-guided stimulation (Malate et al., 1997).

Key Achievements

- **Large-scale power generation:** Installed across multiple interconnected sectors.
- **Integrated field development:** Coordinated operation of Tongonan and Mahanagdong systems with steamline interconnection.
- **Long-term production:** Continuous operation since the early 1980s with staged capacity additions.
- **Advanced reservoir monitoring:** Application of geochemical, pressure, temperature, microseismic, and repeat microgravity data to track reservoir changes.
- **Adaptive reinjection strategies:** Large-scale reinjection supports pressure maintenance across multiple sectors while minimizing thermal breakthrough.
- **Effective well interventions:** Diagnostics-guided stimulation and workovers to restore injectivity and support long-term productivity.
- **Institutional and finance innovations:** Build-operate-transfer structures mobilized private capital while preserving long-term public interest.
- **Sector development capacity:** The Philippines’ multi-decade geothermal program fostered institutional knowledge and a domestic supply chain that reduces development costs.

Lessons Learned

- **Reservoir balance at scale:** Sustained mass withdrawal can exceed natural recharge, causing pressure decline and steam-zone expansion; reinjection and make-up drilling must be proactively managed.
- **Reinjection placement is critical:** Poorly sited injection wells can cause rapid thermal breakthrough and production losses.
- **Structural control dominates:** Faults and fractures associated with the Philippine Fault govern permeability and fluid flow; structural models are essential for well targeting.
- **Integrated monitoring improves decisions:** Combining microgravity, geochemical, and pressure/temperature data strengthens reservoir models and management.
- **Geomechanical awareness is required:** Operations in tectonically active settings demand integrated seismic and stress monitoring to manage operational risk.



Leyte Geothermal Production Field, one of the Philippines' largest geothermal developments. Source: thinkgeoenergy.com

Status and Outlook

The Leyte Geothermal Production Field's long-term performance illustrates both the opportunities and challenges of managing a large, fault-controlled, high-enthalpy system for long-term production.

In 2025, generation fell below 400 MW due to evolving reservoir conditions, declining pressure, higher acidity, and increased solids, combined with plant designs suited to wetter, cleaner steam and aging infrastructure. These factors drove steam quality issues and extended outages, notably Malitbog Unit 2 (Jul 2024–Nov 2025), Tongonan Unit 3 (Jun–Jul 2025), and Tongonan Unit 1 (Aug 2025–Jan 2026). In response, EDC shifted to integrated, complex-wide management with shared targets, ramped up steam quality assurance and resource optimization, and deployed sensors, advanced monitoring, and analytics/artificial intelligence to predict subsurface and plant issues and reduce unplanned downtime.

EDC affirms the resource remains strong and is executing a recovery and redevelopment plan to restore Leyte's long-term reliability and cost competitiveness. Near-term programs target increasing output to about 560 MW in 2026, progressing to approximately 700 MW by 2030 under the Reimagining Leyte modernization, which aligns subsurface, surface, and plant systems to current steam conditions. Priorities include fit-for-purpose surface and plant upgrades, tighter steamfield-plant coordination on loading and maintenance, and disciplined reservoir management and reinjection strategies. With strengthened governance and data-driven operations, Leyte is expected to regain its role as a high-capacity, dependable baseload asset supporting grid stability and the Philippines' energy portfolio. In early 2026, EDC announced plans to expand and upgrade its Leyte geothermal power complex.

MICHOACÁN, MEXICO

Case Study 9:

Los Azufres—Operating a Hydrothermal System with Stimulated Reservoir Activities

Operator:

Comisión Federal de Electricidad

Partners:

National Autonomous University of Mexico (UNAM) and other Geothermal Service Contractors

KEY CHARACTERISTICS

**FINANCING:**

Public utility-driven development (CFE as main developer/operator)
Mexican federal infrastructure and energy investment programs

**EXPERTISE:**

Reservoir engineering, hydrothermal geochemistry, and isotopic monitoring; well stimulation techniques, including acid stimulation and reinjection management and pressure maintenance strategies; structural geology and fault-controlled permeability systems; numerical reservoir modeling and thermodynamic analysis.

**IMPACT:**

Demonstrates potential pathway from conventional hydrothermal to engineered/managed geothermal reservoir systems (next-generation applications).

**POWER PRODUCTION:**

Total Capacity
Approximately 242 MWe

Type of Plant:
Multi-unit binary/flash steam plants (+11 units). Long-term production sustained since early 1980s.

**ROCK TYPE:**

Fractured volcanic rocks and intrusive rocks, including andesites, granodiorites, and deeper crystalline intrusive formations.

**TEMPERATURE:**

Shallow reservoir: 240–280°C (464–536°F)
Deep reservoir: 300–320°C (572–608°F)

**DEPTH:**

Shallow reservoir: 1,300–2,500 m (4,265–8,202 ft)
Deep reservoir: greater than 5,000 m (16,404 ft)

Los Azufres, one of Mexico's largest geothermal fields in the Trans-Mexican Volcanic Belt, has served as a leading R&D platform, advancing reservoir engineering, hydrothermal geochemistry, isotopic monitoring, and numerical modeling to refine understanding of reservoir evolution and production. Los Azufres has decades of operational data and targeted stimulation efforts within a mature hydrothermal system, illustrating a potential pathway from conventional hydrothermal development to engineered next generation applications.

Overview

Los Azufres is one of Mexico's largest geothermal fields, located in the Trans-Mexican Volcanic Belt in Michoacán and operated by the Comisión Federal de Electricidad (CFE). Commercial operations began in 1982. The complex has an installed capacity of about 242 MWe across 11 power plants (Negrín and Lippmann, 2016). Exploration drilling started in 1976; by 1998 more than 67 wells had been drilled, including 33 production wells.

Los Azufres has served as a key site for geothermal research in reservoir engineering, hydrothermal geochemistry, isotopic monitoring, and numerical modeling. To counter natural production decline, CFE has employed reinjection optimization, acid stimulation, and hydraulic fracturing where appropriate. In 2019, the field generated roughly 1,600 GWh for Mexico's grid.

Site Geology and Reservoir Design

Los Azufres is a complex, two-phase system. The northern Maritaro sector is primarily liquid-dominated, while the deeper southern Tejamaniles sector is vapor-dominated. Heat is supplied by shallow magmatic intrusions associated with the Trans-Mexican Volcanic Belt. Long-term production has led to moderate pressure and temperature declines, with localized enthalpy increases indicating progressive boiling and evolving flow paths (Negrín and Lippmann, 2016).

Cooled-water reinjection has been used since 1982 to maintain pressure and enhance near-wellbore permeability. Field experience and independent studies show that thermal contraction during cooled-water injection can increase fracture permeability by several-fold, improving injectivity and supporting long-term mass balance.

The addition of Unit 18 (27 MW) in 2019 required an investment of approximately US\$51 million. Earlier economic analyses estimated production costs for a 25-MW unit at roughly 3.18 US cents/kWh (Hiriart and Andaluz, 2000).

In 2005, well Az-9AD underwent matrix acid stimulation to remove near-wellbore damage. A 20% hydrochloric acid solution with corrosion inhibitor and scale-control additives was pumped through tubing with a packer, using ball sealers for diversion, followed by a freshwater flush. The treatment was conducted below fracture pressure to target damage removal rather than fracture creation. Post-treatment results showed about a 40% flowrate increase, demonstrating the effectiveness of matrix acidizing to achieve permeability restoration in geothermal wells (Flores et al., 2006).



Aerial view of the Los Azufres geothermal power plant. Source: CFE

Key Achievements

- **Sustained baseload generation:** More than four decades of commercial operation supported by adaptive reservoir management and continuous field development.
- **Reservoir stimulation:** Matrix acidizing and selective hydraulic stimulation restored permeability and improved wellbore performance in declining producers and injectors.
- **Reinjection optimization:** Long-term cooled-water injection-maintained pressure and enhanced near-wellbore permeability, reducing decline rates and supporting sustainability.
- **Cost-effective expansion:** Commissioning of Unit 18 (27 MW, 2019) and historically low production costs for similar-sized units demonstrate competitive geothermal economics.
- **Corrosion management:** Mitigation programs addressing hydrogen sulfide, chloride, sulfate, and acidic constituents have been implemented to protect carbon-steel infrastructure.
- **Asset reliability:** Environmental controls and improved HVAC/dehumidification in control buildings reduced humidity-related electrical issues, improving plant availability.



Los Azufres geothermal power station. Source: CFE

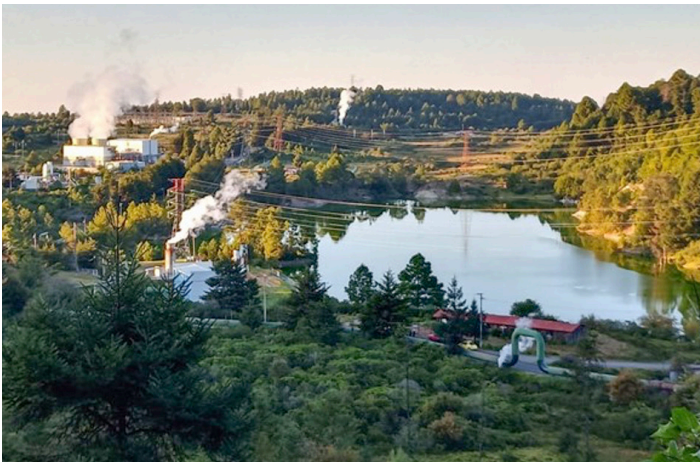
Lessons Learned

- **Magmatic heat source identification:** The use of standard exploration workflow that combines isotopic, geochemical, and geophysical indicators assess whether a magmatic heat source is likely present before advancing drilling.
- **Coupled operations and seismicity:** Production and reinjection can induce small seismic events, underscoring the importance of continuous seismic monitoring and risk management.
- **Targeted stimulation works:** Diagnostics-guided matrix acidizing can significantly increase injectivity and productivity without inducing fractures when operated below fracture pressure.
- **Thermal injection effects:** Cooled-water reinjection can substantially enhance fracture permeability near injectors, supporting pressure maintenance and mass balance.

Status and Outlook

Los Azufres demonstrates that mature hydrothermal fields can sustain and extend productive life through reinjection optimization, targeted stimulation, and modern monitoring. For countries managing aging assets, these practices can defer costly new drilling, stabilize generation, and lower levelized costs.

Continued integration of geochemical/isotopic surveillance, pressure-transient analysis, and induced seismicity monitoring, combined with proactive well maintenance and corrosion control, is expected to support reliable long-term baseload generation from this field.



Los Azufres geothermal power station landscape. Source: CFE

WEST JAVA, INDONESIA

Case Study 10:

Salak (Awibengkok)— The Largest Geothermal Field in Indonesia with Hydraulic Stimulation

Operator:
Star Energy Geothermal
Salak, Ltd

Partners:
PT Pertamina Geothermal
Energy and Perusahaan
Listrik Negara

KEY CHARACTERISTICS



FINANCING:
Public-private
partnership



EXPERTISE:
Characterization of the
reservoir's fracture system
Fluid management



IMPACT:
Largest geothermal field
in Indonesia



POWER PRODUCTION:
Total Capacity:
377 MWe
Type of Plant:
Multiple flash steam units
(55–57.5 MW each)
and a planned 40
MW binary cycle unit
(commissioning 2026)



ROCK TYPE:
Andesitic-to-
rhyodacitic rocks,
liquid-dominated,
fracture-controlled
hydrothermal
system.



TEMPERATURE:
240–312°C
(464–594°F)



DEPTH:
1,500–3,000 m
(4,921–9,843 ft)

The Salak Geothermal Field in West Java is Indonesia's largest operating geothermal system, with an installed capacity of 377 MWe. Operated by Star Energy Geothermal Salak, Ltd., the field has been in production since the 1990s and has undergone significant expansion and optimization including hydraulic stimulation activities in 2012 that improved productivity in declining wells and extended the field's lifetime.

Overview

After nearly 25 years of operation, the Salak Geothermal Field continues to deliver its 377 MWe installed capacity with a sustained net capacity factor of about 95% since 2006. Salak was explored during 1983–1986, with early development wells drilled from 1989–1993, followed by major expansion during 1994–1997 (Golla et al., 2020; Stimac et al., 2008).

Located about 70 km from Jakarta, Salak supplies geothermal steam to a 180-MW power plant operated by Perusahaan Listrik Negara and supplies steam to multiple power plants, totaling 201 MW, that generate electricity for the Java–Madura–Bali grid.

Integrated wellbore data, continuous monitoring, and an updated conceptual model, validated by numerical

simulation, support relocating most reinjection to outfield areas and the southeast margin. Despite substantial early infield injection, field performance has remained robust; cooler natural recharge appears limited and confined to specific, low-flow pathways. Ongoing fit-for-purpose surveillance, iterative process improvements, proactive reservoir management, and adoption of new technologies are expected to sustain high production levels (Golla et al., 2020).

Indonesia has one of the world's largest identified geothermal potentials estimated at 28 GWe (Pambudi and Ulfa, 2024). The Salak field demonstrates what policy commitment, international investment, and technical expertise can deliver in an emerging market context.

Financing and Risk-Sharing Model

Salak's development involved complex public-private partnerships with risk shared among government, state-owned enterprises (Perusahaan Listrik Negara, Pertamina Geothermal Energy), and international private investors. The project's trajectory reflects Indonesia's regulatory evolution from mining law oversight to a dedicated geothermal law.

Site Geology and Reservoir Design

Developed within a Quaternary volcanic complex, the reservoir is hosted in andesitic-to-rhyodacitic rocks overlying Miocene sedimentary formations and is characterized by strong fracture-controlled permeability aligned with dominant north to northeast structural trends (Stimac et al., 2008).

Reservoir temperatures range from 240°C to over 300°C, with a western upflow zone where deep fluids ascend along major structural conduits and then spread laterally through a compartmentalized fracture network. With approximately 10% porosity and low matrix permeability, flow is fracture-dominated, classifying the system as a conventional hydrothermal resource.

Since the start of operations, the field has maintained a high net capacity factor, averaging 91%–95%, supported by reinjection and adaptive reservoir management strategies (Golla et al., 2020). Ongoing optimization, including reinjection realignment outside the main production zone and improved conceptual reservoir modeling, has mitigated challenges such as thermal breakthrough, non-condensable gas accumulation, and recharge variability, supporting stable long-term steam production.

Key Achievements

- **Performance:** By 2017, Salak produced 483,000 MM kg of steam and generated 59,307 GWh of net electricity, maintaining a net capacity factor of 91–95% since commercial operations began (Golla et al., 2020). Turbine upgrades and operational adjustments improved output efficiency.
- **Commercial production start:** Power generation began in 1994 with two 55 MWe units, expanding to a total of 377 MWe by 2002–2005 through additional units and turbine uprates.
- **Surface facility optimization:** Steam supply increased through gas removal upgrades, pipeline debottlenecking, and targeted infrastructure adjustments without drilling new wells.
- **Refined reservoir models:** Integrated geophysical, chemical, and drilling data were used to map fracture networks and guide make-up wells. Campaigns in 2003–2005, 2006–2009, and 2012–2013 targeted high-permeability zones identified by the conceptual model to sustain production.
- **Reservoir management:** Strategies included hydraulic stimulation in 2012 to improve productivity in declining wells, extending field lifespan.
- **Fluids management:** Condensate and brine injection was shifted outside the production zone to sustain pressure and promote steam-cap growth; scale cleanouts using wireline/coiled tubing were applied and select injection wells were converted to production.
- **Dedicated geothermal law:** Enacted in 2003 and revised in 2014, law No 21 enabled private investment by separating geothermal development from mining law restrictions and provided regulatory certainty for private co-investors.

Lessons Learned

- Fracture-controlled flow dominates reservoir behavior; understanding structural permeability is critical for long-term production.
- Reinjection strategy is key; misplaced injection can interfere with production wells and delay steam-cap development.
- Non-condensable gases require monitoring and management to maintain turbine efficiency.
- Continuous modeling improves decisions, supporting optimal make-up well placement and injection planning.
- Volcanic activity and recharge variability can affect shallow reservoir conditions, requiring adaptive operational responses.

Status and Outlook

Salak's operational record demonstrates that long-term, high-temperature geothermal production is achievable through active reservoir surveillance and adaptive operational strategies. Data from recent wells and monitoring programs have guided make-up well targeting toward high-permeability zones in the northern and eastern parts of the field, aligning wellbore trajectories with dominant structural trends to optimize fracture connectivity. Anticipated operational challenges including wellbore scaling and increased

non-condensable gases in developing steam caps are addressed with established scale-cleaning techniques and targeted venting. Surface facility optimizations, such as gas removal upgrades, pipeline improvements, and conversion of select injection wells to production, have added steam without additional drilling. Continuous monitoring, iterative model updates, and proactive management support efficient operation of the Salak field at its current high-capacity generation (Golla et al., 2020).



Salak Geothermal Power Plant, one of Indonesia's largest geothermal power facilities.

Source: <https://www.starenergygeothermal.co.id/salak/>

AKITA PREFECTURE, JAPAN

Case Study 11:

Sumikawa Geothermal Plant—Cold-Water Stimulation in Japan

Operators:

Tohoku Sustainable &
Renewable Energy Co. Inc and
Mitsubishi Materials Corporation

Partner:

Mitsubishi Gas Chemical
Company, Inc.

KEY CHARACTERISTICS



FINANCING:

Mix of corporate R&D investment, technology transfer, and innovative engineering solutions



EXPERTISE:

Cold-water stimulation as a low-seismicity alternative



IMPACT:

Plant has operated stably since it opened in 1995



POWER PRODUCTION:

Installed Capacity:
50 MWe

Type of Plant:
Single flash steam

Commercial off taker:
Tohoku Electric
Power Co., Inc.



ROCK TYPE:

Liquid-dominated, high-temperature hydrothermal system in a volcanic-graben setting with fracture-controlled flow



TEMPERATURE:

200–300 °C
(392–572°F)



DEPTH:

1,600–2,500 m
(5,249–8,202 ft)

The Sumikawa geothermal field is a high-temperature, fractured volcanic reservoir that supports roughly 50-MW-class baseload power with high availability. The field employs systematic reinjection to maintain reservoir pressure and manage brine responsibly. Operations have demonstrated effective well and reservoir management, most notably cold-water stimulation/reinjection campaigns that improved injectivity and helped sustain productivity in multiple wells, while monitoring and mitigation practices limit scaling, corrosion, and induced seismicity. Together, these features underpin reliable, long-lived power generation for next-generation geothermal systems.

Overview

The Sumikawa geothermal plant in Akita Prefecture, operated by Tohoku Sustainable & Renewable Energy Co. Inc and Mitsubishi Materials Corporation, lies in a mountainous setting near hot springs, ski resorts, and national parkland conditions that pose distinct public support challenges for geothermal development in Japan.

The moderate-scale field has produced about 50 MWe since 1995 from a fracture-controlled, liquid-dominated volcanic hydrothermal system. Extensive field studies have focused on characterizing fracture flow and optimizing reinjection. Tracer tests indicate strong hydraulic connectivity between reinjection and production wells, with breakthrough observed within

roughly 48 hours and evidence of rapid fluid recycling (Kumagai et al., 2004). Geochemical monitoring corroborates this behavior, suggesting a significant portion of reinjected fluids can return to the production zone over short timescales (Kumagai et al., 2004; Ariki et al., 2000).

Numerical modeling and history matching have been used to evaluate reservoir performance and refine the conceptual model, emphasizing the need to represent pressure distribution and two-phase steam-water conditions to predict high-enthalpy production and reinjection effects (Kondo et al., 2017). Integrated geological, geophysical, and geochemical investigations, including resistivity modeling and alteration mineral

analyses, have further constrained the cap rock, permeability architecture, and temperature distribution (Ariki et al., 2000), underscoring the central role of fracture-controlled flow and rapid fluid circulation in reservoir management.

To maximize thermal recovery during brine and condensate recycling, production and reinjection areas were spatially separated, wells were spaced widely to limit interference, and cold-water stimulation was applied to enhance injectivity and productivity, collectively reducing the number of wells required to achieve 50 MWe capacity.



Sumikawa Geothermal Plant Aerial View.

Source: Tohoku Sustainable & Renewable Energy Co., Inc.

Site Geology and Reservoir Design

The Sumikawa geothermal field is underlain by Tertiary dacitic pyroclastics, marine sediments, altered andesite, and a granitic intrusion emplaced into the Tertiary section. These units are capped by Quaternary andesitic lavas and lacustrine sediments that serve as an effective seal. Reservoir permeability is dominated by fractures. In the southern sector, temperatures approach 300°C at around 1,600 m vertical depth, increasing progressively toward the volcanic chain to the south and declining sharply to the north. A steam–water two-phase zone lies beneath the cap rock above the hot liquid reservoir, with this interval thickening southward.

A key reservoir design feature at Sumikawa was the use of cold-water stimulation to enhance wellbore performance

without resorting to high-pressure hydraulic fracturing. Intermittent high-rate injections at relatively low wellhead pressures, applied in repeated inject/shut-in cycles to seven wells, induced thermal stresses that opened existing fractures and increased permeability. Following these treatments, productivity improved in two wells and injectivity increased in five; laboratory tests on rock specimens subjected to cyclic heating and cooling showed corresponding permeability gains, reinforcing the field observations (Kitao et al., 1995). These measures contributed to reducing the number of production wells needed to achieve the 50 MWe of generation capacity.

Key Achievements

- The Sumikawa geothermal field has achieved stable, long-term operation within a structurally complex volcanic setting by combining rigorous reservoir characterization with disciplined management. Since 1995, it has maintained approximately 50 MWe of continuous generation, enabled by targeting high-temperature zones in the southern sector near the heat source and by implementing a reinjection program that sustains pressure while minimizing rapid thermal decline (Ariki et al., 2000).
- Several multi-tracer tests clarified fracture connectivity and dominant flow paths, with rapid tracer returns demonstrating highly permeable pathways between reinjection and production wells. These insights guided well siting and reinjection placement, showing that even with north–south spatial separation, significant fluid returns can occur on short timescales and must be actively managed.
- An integrated interpretation of geophysical, geological, and geochemical data defined the reservoir architecture and cap rock, with clay-rich alteration zones delineating boundaries and aiding fluid containment. Ongoing geochemical monitoring of production fluids has supported operational decisions by identifying reinjection breakthrough and tracking reservoir evolution, reinforcing a responsive, data-driven approach to field management.



Sumikawa geothermal power station begins operations in 1995.
Source: Mitsubishi Materials Corporation



Sumikawa geothermal power station pipeline and cooling towers.
Source: Mitsubishi Materials Corporation

Lessons Learned

- Sensitive-area development is feasible with careful siting, subsurface-focused infrastructure, and structured benefit-sharing. Sumikawa is near national parks and onsen (Japanese hot springs) and presents an example of how to minimize surface footprints and engage local stakeholders.
- Lessons from rapid fluid recycling and fracture-dominated flow at Sumikawa can inform the development of similar volcanic geothermal systems.
- Multi-tracer tests are essential for resolving fracture-controlled flow, enabling more accurate mapping of connectivity, flow paths, and reinjection impacts.
- Cold-water stimulation offers a lower-risk alternative to high-pressure hydraulic fracturing where induced seismicity is a concern. Thermal stress can enhance permeability in hydrothermal reservoirs without the pressures associated with EGS-style stimulation.

Status and Outlook

Sumikawa highlights the importance of managing highly connected fracture systems for long-term energy production. Near-term priorities include refining conceptual reservoir models by integrating tracer, geochemical, and geophysical data to better predict fluid circulation and thermal evolution. Optimizing reinjection, particularly well placement and injection rates, is essential to reduce short-circuiting and preserve reservoir temperatures. Closer integration of continuous monitoring with numerical modeling will improve forecasting of reservoir response and guide more effective make-up well targeting.

THUWAL, SAUDI ARABIA

Case Study 12:

KAUST Project on the Red Sea Coast, Kingdom of Saudi Arabia— De-Risking a Sedimentary Geothermal Frontier

The King Abdullah University of Science and Technology Geothermal Exploration Project (K-GEP) is an early-stage, promising geothermal initiative aimed at supporting energy systems.

Overview

This project focuses on the Kingdom of Saudi Arabia's Red Sea coast, where medium-enthalpy geothermal resources may be hosted in deep rift-basin sedimentary aquifers. Geothermal energy is especially valuable for Saudi Arabia because it could provide reliable, around-the-clock heat for direct uses such as desalination, district cooling, and potentially mineral recovery from brines. A shallow pilot well drilled in 2024 served mainly as a reconnaissance and monitoring well and allowed the team to collect geological, geophysical, thermal, and geochemical data needed to reduce uncertainty before deeper drilling.

Challenges

A key challenge for this project has been characterizing the geothermal resource, including subsurface geology and faulting, reservoir and aquifer properties, temperature distribution at depth, drilling feasibility in heterogeneous formations, and the economic viability of heat extraction from sedimentary basin brines. During drilling, the project encountered tight hole conditions, stuck pipe, partial mud losses, and hole enlargement/washouts, creating operational challenges. At depths of 195–225 m, anhydrite interlayered with chert caused additional instability.



Location of K-GEP project on the Kingdom's Red Sea coast.
Source: Finkbeiner et al., 2025

Approach

Researchers at the King Abdullah University of Science and Technology (KAUST) established a pilot well and structural investigations and operation interventions for the challenges encountered while drilling. The pilot well was drilled to a depth of 400 meters and allowed for the collection of drill cuttings, gamma ray caliper, resistivity, and temperature logs. Researchers also installed a permanent fiber-optic cable to conduct distributed acoustic sensing (DAS) and distributed temperature sensing (DTS). A passive seismic monitoring system that included a broadband seismic station, node arrays, and a borehole seismometer was inserted to image shallow subsurface structures, estimate shear-wave velocity profiles, monitor ambient noise and seismic activity, and track well temperature behavior overtime. Brine chemistry, seawater comparison, and lithium and metal enrichment potential were measured from collected formation water samples. To mitigate the mud loss issue encountered while drilling, bentonite and carboxymethyl cellulose were introduced.

Results

The successfully drilled, cased, cemented and instrumented pilot approach produced several key discoveries. The project identified a heterogeneous lithology that consisted of sandstone, claystone, gypsum, anhydrite, chert, and dolomite. Additionally, at a depth of 75 meters, a major non-conformity of Plio/Pleistocene Lisan group and mid-Miocene Kial formation was identified. Thermal measurements produced an average geothermal gradient of 31°C/km. At a depth of 333 meters, a high temperature of 42.3°C was reached after thermal stabilization. The results from passive seismic monitoring were consistent with drilling-based lithological interpretation, demonstrating that the monitoring system can effectively image the subsurface. Chemistry of water from the bottom of the well was compared to Red Sea seawater sample and showed a higher salinity and an elevated concentration of lithium (0.76 ppm), strontium (140 ppm), iron (1.73 ppm), and manganese (4.67 ppm). The results demonstrate that the region has the potential for low- to medium-enthalpy geothermal development and possible mineral recovery from brines.

Key Insights

- A shallow, highly instrumented pilot well is an **effective first step for geothermal de-risking**.
- Even without producing geothermal heat, the pilot well provided **critical data on geology, drilling behavior, thermal gradient, subsurface structure, and brine chemistry**.
- Geological data alone are not enough. **Combining drilling, logs, fiber optics, seismic monitoring, and geochemistry support subsequent phases of exploration**.
- Drilling through heterogeneous sedimentary sequences is challenging, so **careful mud design and drilling adaptation are essential**.
- **Direct-use** geothermal applications **may be more practical in the near term** than electricity generation, especially for **desalination and cooling**.
- The enriched lithium and metal content suggests that combining **geothermal energy with mineral extraction could improve project economics**.
- The next logical step is a deeper geothermal doublet system **to test circulation, heat extraction, and integration with KAUST campus facilities**.

SAN ANTONIO DE LOS COBRES, ARGENTINA

Case Study 13:

Tocomar Geothermal System, Argentina—Exploring a High-Altitude Resource Through Structural and Geophysical Exploration

Tocomar is a high-enthalpy, fault-controlled geothermal system situated at approximately 4,300 meters above sea level in the Central Andes.

Overview

The Tocomar geothermal system is associated with the Quaternary Tocomar volcanic center and the Calama-Olapato-Toro lineament, a major structural feature that controls fluid circulation. In addition to its geological significance, Tocomar stands out because of its location within the emerging Central Puna Energy Hub, where it benefits from proximity to roads, railway infrastructure, a high-voltage interconnection line, solar generation, and major mining projects.



Tocomar Geothermal Area, a high-altitude geothermal exploration site in the Argentine Andes. Source: ThinkGeoenergy 2016.

Challenges

Tocomar's location presents opportunities to access major fault systems but also creates extreme conditions to operate in, leading to a broad regional gap between resource potential and actual development. Advancing greenfield geothermal projects in high-altitude back-arc setting presents difficult technical and accessibility considerations where commercial development remains limited. Projected development costs that include exploration, scalability, policy and finance frameworks needed to support geothermal deployment remain uncertain, creating an additional layer of risk. Assessments that have been conducted demonstrate that generation potential estimates are heavily influenced by recovery factor, reemphasizing the need for exploration drilling and long-duration well testing for geothermal resource confirmation.

Approach

To address the risk associated with geothermal deployment at Tocomar, a phased multidisciplinary strategy was implemented by Consejo Nacional de Investigaciones Científicas y Técnicas (CONICET) research groups with international collaborators. The phases included structural investigations, reservoir characterization, and geochemical analysis:

- Detailed structural investigations to identify Calama-Olapato-Toro-related faults and local extensional systems control (Ahumada et al., 2023).

- Geological mapping to locate structural intersections that create favorable upflow zones.
- 3D audio-magnetotelluric (AMT) inversion modeling to image the subsurface (Ahumada et al., 2022).
- Geothermometric studies to estimate deep reservoir temperatures.
- Petrophysical studies to confirm structurally enhanced permeability and effective cap-rock sealing.
- Probabilistic resource assessment using the U.S. Geological Survey Heat-in-Place volumetric method and Monte Carlo simulations to quantify generation potential and better frame exploration risk.

Results

The approach implemented by the CONICET research group produced several key discoveries of Tocomar features. Tectonic structures were hypothesized to be the main control on hydrothermal circulation and reservoir behavior (Ahumada et al., 2023). 3D AMT revealed a conductive clay cap at a depth range between 200 and 500 meters as well as a potential primary reservoir in fractured Ordovician basement rock at a depth range of 1,000 to 1,500 meters. The reservoir temperature observed was about 235°C (Ahumada et al., 2022). Permeability and sealing conditions were determined to be favorable, improving overall confidence in the conceptual reservoir model. A resource assessment also showed that potential electrical generation capacity ranged between 6 MWe (conservative case) and 28 MWe (optimistic case). This established Tocomar as a strong candidate for supplying reliable baseload energy to support mining operations and complement solar power in the Central Puna region.

Key Insights

- Integrated multidisciplinary exploration can significantly reduce uncertainty before expensive drilling begins.
- In structurally controlled geothermal systems, fault architecture and structural intersections are critical for identifying the best drilling targets.
- Advanced geophysical tools, especially 3D AMT, are highly valuable for defining reservoir geometry and cap-rock distribution.
- Probabilistic resource assessment is essential for understanding risk and communicating realistic development potential.
- Proximity to grid infrastructure, mining demand, and other energy assets can strongly improve geothermal project viability in otherwise remote areas.
- Tocomar may also serve as a natural laboratory for next-generation and higher-temperature geothermal technologies.



Tocomar Geothermal Area, a high-altitude geothermal site in the Argentine Andes. Source: Dr. Rubén Filipovich 2026



Tocomar Geothermal Area, a high-altitude geothermal site in the Argentine Andes. Source: Dr. Rubén Filipovich 2026

Section 5:

Evaluation Framework:

How Are Options Considered?

Choosing among geothermal technology pathways requires systematic evaluation across multiple dimensions. This section provides a structured framework for project and policy decision-makers, drawing on criteria and methods identified across the 13 case studies.

5.1 Resource and Site Conditions Assessment

The first step in any geothermal evaluation is characterization of the subsurface resource. For example, the methods and data sources considered in the Case Studies included the following:

ASSESSMENT COMPONENT	METHODS AND DATA SOURCES
Temperature gradient mapping	Temperature logs, 3D geological and thermal model, hydrocarbon bottom-hole temperatures datasets, hydrothermal geochemistry, heat flow maps
Permeability characterization	Well testing and completion data, multi-tracers' tests, nano tracers, propped stimulation and diagnostic testing,
Geomechanical assessment	2D and 3D structural models, horizontal drilling, multistage stimulation, validated coupled geomechanical, thermal, and reservoir simulation models
Seismic hazard evaluation	Distributed acoustic sensing (DAS), fiber-optic monitoring systems, seismic networks, DOE-aligned protocols,
Surface conditions	Existing facilities, proximity to transmission infrastructure, water availability

For countries with limited geothermal data, national initiatives such as Utah FORGE and Soultz-sous-Forêts are developing open-access subsurface data tools and regional resource assessments. CEM countries are encouraged to engage with these resources as a first step in national-level evaluation.

5.2 Capital and Operating Cost Framework

Geothermal project costs are dominated by upfront capital expenditure. The cost breakdown varies significantly by technology type:

COST COMPONENT	TYPICAL SHARE OF TOTAL COST HYDROTHERMAL	TYPICAL SHARE OF TOTAL COST EGS
Exploration and resource assessment	10–20%	5–15%
Drilling and well completion	25–45%	40–60%
Surface power plant and equipment	30–45%	20–35%
Transmission and grid connection	5–10%	5–15%
Operations and maintenance (annual)	2–4% of capital cost per year	2–4% of capital cost per year

Source: cost shares are drawn from NLR's Annual Technology Baseline for hydrothermal and EGS; base year cost for closed-loop and superhot geothermal systems have not been estimated; ranges reflect variation across the case studies presented in this report.

For next-generation EGS systems at scale, NLR's Annual Technology Baseline (2024) projects LCOE reductions from current levels of \$80–120/MWh to \$50–70/MWh by 2035 under a moderate advancement scenario, driven primarily by drilling cost reductions and learning curve effects. Under an advanced scenario, LCOE could reach \$40–50/MWh, competitive with new combined-cycle gas generation in many markets (Beckers et al., 2014; Prilliman, 2023; NLR ATB, 2024). The Geothermal Electricity Technology Evaluation Model (GETEM), as implemented in NLR's System Advisor Model™ (SAM), supports bottom-up modeling of geothermal project exploration, drilling, field development, surface-plant performance, and project financing. It can also be used to conduct scenario-based or probabilistic sensitivity analyses covering key variables such as drilling depth, well success rate,

reservoir temperature, flow rate, capacity factor, financing terms, project schedule, and contingency allowances (Prilliman, 2023; NLR, 2024).

Techno-economic performance of closed-loop geothermal systems varies strongly by site and is driven mainly by drilling depth, drilling cost, and working-fluid mass flow rate. Closed-loop geothermal systems may become viable in selected high-temperature settings, but broad competitiveness depends on major reductions in drilling cost and, in many cases, deeper drilling and careful flow-rate optimization (Hakes et al., 2025). Evaluation of these systems has been enabled through multi-organization collaborative consortia, including the U.S. Department of Energy Office of Geothermal-funded Closed-Loop Geothermal Working Group, which is focused on assessing the techno-economic performance of closed-loop systems for heating and power generation (GeoCLUSTER, 2026).

5.3 Financing and Risk Profile

Geothermal projects require specialized financing approaches that reflect their distinctive risk profile. The key risk categories are:

1. **Resource risk:** Uncertainty about subsurface temperatures, permeability, and flow rates—highest in exploration phase, reduced after well testing
2. **Technical risk:** Uncertainty about well construction, reservoir stimulation success, and power plant performance—mitigated by technology maturity and qualified operators
3. **Regulatory risk:** Permitting timelines, policy changes, and grid access—addressed through clear legal frameworks and long-term offtake agreements
4. **Financing risk:** Cost overruns, construction delays, and refinancing needs—mitigated through robust project finance structures and contingency reserves

Concessional and blended finance instruments, including first-loss capital, guarantees, and below-market debt from institutions such as the U.S. International Development Finance Corporation (DFC), the Export-Import Bank of the United States (EXIM), and multilateral development banks, are frequently the difference between a resource that is technically sound and a project that reaches financial close. Countries and developers evaluating financing options should assess, early in project design, whether their risk profile and country context make them eligible for these

instruments, since the application and due diligence timelines for concessional finance are typically longer than for commercial debt and should be factored into overall project scheduling.

Financing should be matched to project stage. Reconnaissance and exploration commonly require grants, public geological surveys, government-funded drilling, resource-risk insurance, guarantees, or concessional and first-loss capital. After the resource is confirmed through well testing, projects can transition to sponsor equity, development-finance loans, commercial debt, green bonds, and long-term offtake-backed project finance. The World Bank/Energy Sector Management Assistance Program (ESMAP) Geothermal Handbook and comparative reviews of geothermal resource risk mitigation mechanisms provide frameworks for screening these options (World Bank/ESMAP, 2012; La Rocca et al., 2017).

Risk-Sharing Mechanisms for Next-Generation Geothermal

- Public exploration drilling programs that generate shared subsurface data, reducing risk for private developers
- Government-backed resource risk insurance or guarantee instruments
- Blended finance structures combining concessional public funds with commercial debt and equity
- Production-linked support mechanisms (feed-in tariffs, capacity payments) that provide offtake certainty
- Multilateral development bank co-investment and first-loss tranches in project finance packages.

5.4 Grid Integration and Infrastructure

Geothermal power projects should be planned in coordination with existing and anticipated grid infrastructure. Although geothermal facilities generally have a compact surface footprint, their location is primarily determined by subsurface resource conditions. Where suitable resources are located near load centers or existing transmission corridors, projects may benefit from lower interconnection costs and reduced infrastructure requirements.

Key grid-integration considerations include:

- **Transmission access:** Distance to the nearest suitable connection point, available network capacity, and the need for new lines or system upgrades.
- **Interconnection requirements:** Technical studies, protection and control requirements, permitting, and the timing of utility approval processes.
- **Grid-support services:** The plant's ability to contribute frequency response, reactive power, voltage support, inertia, and other ancillary services.
- **Operational flexibility:** The extent to which the plant can adjust output, operate in load-following mode, or support changing system conditions.
- **Hybrid-system opportunities:** Potential coordination with energy storage, district energy systems, or other generation and infrastructure assets.
- **Behind-the-meter supply:** Direct, non-grid-connected delivery to a co-located load, such as a mining operation, industrial facility, or data center, reducing dependence on transmission access and interconnection timelines.
- **Microgrid integration:** Operation within an islanded or grid-connected microgrid, requiring assessment of backup, black-start, and grid-support capabilities alongside the primary generation role.

Grid integration and transmission screening is beneficial during site selection rather than after the geothermal resource has been confirmed. Early analysis should evaluate available interconnection capacity, required network upgrades, transmission-expansion needs, potential grid-support services, and any opportunities for coordinated or hybrid operation. The IEA's *The Future of Geothermal Energy* discusses geothermal flexibility and its broader value to the energy system, while NLR's 2019 *Standard Scenarios Report: A U.S. Electricity Sector Outlook* provides a framework for evaluating transmission expansion and grid-system requirements. Identifying these considerations early is important because interconnection and transmission upgrades can materially affect project cost, schedule, financing, and overall bankability (IEA, 2024; Cole et al., 2019).

5.5 Public Support and Risk Mitigation

Public opinion can be a significant constraint on geothermal development, and the issues that matter most vary by technology, site conditions, and community context. Concerns may include potential impacts on hot springs and other geothermal features, induced seismicity, subsurface stimulation, groundwater and surface-water resources, protected areas, agricultural land, culturally important sites, Indigenous or traditional land rights, tourism, local livelihoods, and the distribution of project costs and benefits. These concerns may be influenced by both actual project risks and public perceptions of drilling, injection, and stimulation methods, making early engagement, transparent communication, and credible monitoring essential to successful project development (IEA, 2024; IRENA, 2023).

Key environmental and social considerations include:

- **Induced seismicity and subsurface stimulation:** Concerns about felt seismic events, property damage, and the use of hydraulic stimulation should be addressed through site-specific risk assessment, baseline monitoring, publicly available traffic-light protocols, transparent disclosure of operating methods, and clear response procedures.
- **Water resources and geothermal manifestations:** Potential effects on groundwater, surface water, hot springs, and other geothermal features should be evaluated through baseline studies, monitoring, reinjection strategies, and water-management plans.
- **Land use, visual impacts, and local disruption:** Project siting should consider protected areas, landscape character, tourism, noise, traffic, construction activity, and competing land uses.
- **Livelihoods, cultural heritage, and community rights:** Projects should assess potential impacts on local businesses, agriculture, tourism, culturally important places, and Indigenous or traditional land interests.
- **Community participation and benefit sharing:** Early engagement, subsurface basics education, accessible grievance mechanisms, local employment opportunities, benefit sharing agreements, and transparent communication can help ensure that affected communities participate meaningfully in project decisions and benefits.

Environmental and social risk management should begin during site selection and continue throughout development, operation, and closure. DOE's Protocol for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems, the International Finance Corporation's Performance Standards on Environmental and Social Sustainability, and the World Bank's Environmental and Social Framework provide relevant approaches for identifying, assessing, mitigating, and disclosing project risks. Project plans should include baseline environmental and social studies, transparent descriptions of proposed drilling, stimulation, and operating methods, monitoring and mitigation measures proportionate to the identified risks, early and continuing stakeholder engagement, accessible grievance mechanisms, and appropriate arrangements for community benefits. Addressing these issues openly and at an early stage can strengthen social support, improve project design, and reduce the risk of regulatory delays, public opposition, or conflict during development and operation (Majer et al., 2012; IFC, 2012; World Bank, 2016).

5.6 Workforce, Supply Chain, and Local Content Development

A geothermal project's cost and schedule depend heavily on the availability of skilled labor, specialized equipment, and capable domestic suppliers. These factors are often given less attention during early project planning than resource uncertainty and financing risk, even though shortages can result in significant delays and cost increases (Gehring and Loksha, 2012).

Drilling is frequently the most immediate workforce and supply-chain constraint. Directional and horizontal drilling rigs, high-temperature logging tools, specialized well-completion equipment, and crews with geothermal experience are concentrated in a limited number of markets. Countries with established oil and gas or mining sectors may have a meaningful advantage because existing rig fleets, drilling crews, service companies, and subsurface expertise can often be adapted through targeted training rather than developed entirely from the ground up. Fervo Energy's experience illustrates how oil and gas drilling technologies, operational practices, and workforce capabilities can be transferred directly to next-generation geothermal development.

Other capabilities, including reservoir engineering, geoscience, geochemistry, plant operations, land management, environmental permitting, health and safety, and community engagement, can take many years to develop domestically. The Philippines and

Iceland case studies demonstrate that sustained national programs, university and industry partnerships, on-the-job training, and experience accumulated within utilities and operating companies can progressively establish these capabilities. Workforce development should therefore be treated as a long-term component of national geothermal planning rather than as a requirement addressed only after projects enter construction.

DOE's Workforce Development Opportunities emphasizes education, hands-on training, industry-recognized credentials, research opportunities, and partnerships among government, academic institutions, and industry. Similarly, IRENA and the International Labour Organization's Renewable Energy and Jobs: Annual Review 2025 highlights the importance of skills development, workforce inclusion, and domestic supply-chain capacity in converting renewable-energy investment into durable employment and economic benefits. Drawing on these approaches, a country-level workforce assessment should identify capabilities that can be transferred from the oil and gas, mining, power-generation, and construction sectors; determine gaps in specialized technical and nontechnical skills; and evaluate the ability of domestic training institutions and suppliers to address those gaps (DOE, 2026; IRENA and International Labour Organization, 2026).

Local-content targets should be phased according to project maturity and existing domestic capacity. Early requirements that exceed the capabilities of the local workforce or supply chain may increase project costs, restrict competition, and delay implementation. Over time, however, local-content objectives can be progressively increased and linked to accredited training, apprenticeships, university-industry partnerships, workforce-transition programs, and supplier-development initiatives. This approach can reduce project delivery risks while building lasting domestic expertise, employment, and industrial capacity.

Section 6:

Decision-Relevant Outputs: Applying Case Study Lessons

The case study evidence, taken together, yields a structured framework for national decision-makers seeking to evaluate, plan, and advance geothermal deployment in their own contexts. This section translates the lessons from individual projects into actionable guidance.

6.1 Country-Specific Decision Pathway

The GeoFuture Decision Pathway

- Step 1: CONTEXT ASSESSMENT:** Characterize national energy goals, resource endowment, and enabling conditions
- Step 2: TECHNOLOGY SCREENING:** Identify applicable pathways based on geology, fluid presence, risk tolerance, and development timeline
- Step 3: EARLY VALIDATION:** Commission targeted subsurface assessment, exploratory drilling, or data compilation to reduce uncertainty
- Step 4: PILOT DEVELOPMENT:** Demonstrate technology and resource in a field pilot, generating bankable data
- Step 5: COMMERCIAL FINANCING:** Structure project finance based on validated resource and technology data
- Step 6: SCALE-UP:** Apply learning-curve effects through standardized designs and expanded development

6.2 Technology Consideration

Based on case study evidence, geothermal development depends heavily on local context rather than a single best solution. In places with very high heat and volcanic geology, conventional hydrothermal systems may be a natural fit, while higher-temperature next-generation options could also become relevant where natural fluid is not present. In areas with more moderate heat and faulted or extensional geology, conventional binary systems or newer enhanced geothermal approaches are possible directions, especially where more research and testing can happen first. Where the resource sits in sedimentary basins with good natural porosity and permeability, development leans toward options that can work with lower-temperature conditions, including closed-loop concepts and binary generation.

For mature hydrothermal fields that are starting to decline, the case studies highlight ways to make better use of the existing resource, such as reservoir stimulation or adding binary systems to capture lower-enthalpy heat. In places where induced seismicity is a major public concern, lower-risk pathways that avoid or reduce stimulation can be considered.

Geothermal choices are not just about site geology and reservoir design. Countries with limited drilling experience may find it easier to start with more familiar hydrothermal opportunities and build capability over time through partnerships. In emerging markets with limited private investment, public support for early exploration and blended financing can help reduce risk and make projects more feasible. Overall, geothermal technologies offer a flexible set of options that should be matched with resource conditions, local capacity, financing, and public acceptance.

6.3 Identification of Bankable Opportunities

Private capital is available for geothermal development—but it requires credible data. Based on case study evidence, projects become increasingly bankable as they progress through the following data milestones:

DATA MILESTONE	TYPICAL EFFECT ON FINANCING
Regional resource assessment (temperature gradient maps, available well data)	Enables initial screening; qualifies for concessional exploration finance
Exploratory well drilled with temperature logging	Demonstrates resource temperature; qualifies for early-stage risk capital
Flow test in exploratory well	Demonstrates permeability; major reduction in lender risk premium
Pilot production well with 90-day production test	Demonstrates commercial flow rates; enables project finance term sheet
Signed power purchase agreement with creditworthy offtaker	Provides revenue certainty; enables commercial debt on market terms
Operating plant with 12+ months of production data	Eliminates residual resource risk; enables refinancing at reduced cost of capital

6.4 Considerations for National Planning and Feasibility Studies

CEM member countries seeking to incorporate geothermal into national energy planning may consider the following inputs, based on case study evidence:

1. Include geothermal in national electricity system modeling with its full capacity value—not just LCOE comparison, but system integration value as a firm, dispatchable resource (NLR ATB 2024 provides appropriate modeling parameters)
2. Commission national geothermal resource assessments using available subsurface data, leveraging international technical expertise and technical assistance where available

3. Establish a dedicated geothermal legal and regulatory framework if one does not exist—drawing on Indonesia’s Geothermal Law model as the most comprehensive developing-country template
4. Develop a national geothermal risk-sharing instrument—such as a government-backed exploration drilling fund or resource risk insurance product—to reduce private investor risk premium
5. Build institutional capacity in geothermal regulation, permitting, and environmental management within relevant national agencies.

6.5 Opportunities Beyond Power Generation

While this report focuses primarily on electricity generation, several case studies point to revenue and development opportunities that extend well beyond the power plant gate, and that CEM member countries could weigh when building the investment case for a geothermal project.

Direct-use applications, including district heating, greenhouse agriculture, aquaculture, and industrial process heat, can generate revenue from lower-temperature resources that would not otherwise justify power plant development. Berlin’s use of residual geothermal heat for direct-use applications beyond electricity is one modest but replicable example of extending resource value in this way.

Geothermal co-production with oil and gas and the repurposing of existing wells represent additional opportunities, particularly in regions with established hydrocarbon production. Geothermal energy can be produced from hot fluids associated with active oil and gas operations, while existing or inactive wells may also be converted or repurposed for geothermal use. These approaches can leverage existing subsurface data, well management, surface infrastructure, and access rights, potentially reducing exploration requirements and development costs. They may be particularly relevant for countries with substantial oil and gas sectors seeking to leverage existing assets and technical capabilities for geothermal development.

Critical mineral co-production, particularly critical metals extraction from geothermal brines, is an emerging opportunity in some resource types and is noted here as an area for CEM countries to monitor, though it remains commercially unproven at scale in the projects reviewed in this series.

Section 7:

Key Takeaways:

What the Series Shows Us

Across 13 case studies spanning four technology types and 11 countries, six consistent takeaways emerge for CEM member countries and GeoFuture Initiative partners.

Takeaway 1: Context Determines Technology Choice

There is no universally optimal geothermal technology. The right pathway depends on geology, risk tolerance, financing environment, regulatory context, and national energy goals. Countries with high heat gradients and existing hydrothermal resources might prioritize proven hydrothermal development; countries with low-permeability hot crystalline basement and access to drilling expertise may consider EGS; countries with sedimentary basins and low seismicity tolerance can explore closed-loop approaches.

Country Insight

Indonesia's success with large-scale hydrothermal development (Salak, 377 MWe) reflects favorable volcanic geology, dedicated regulatory reform, and sustained public-private partnership structures. These conditions do not exist everywhere—but elements of the Indonesian model could be replicable through targeted policy and financing interventions.

Takeaway 2: Early Assessment and Validation Lowers Cost and Risk

Projects that invest in detailed subsurface data acquisition before committing capital to production development consistently achieve better outcomes, lower drilling failures, faster reservoir development, and more favorable financing terms. The Utah FORGE field laboratory embodies this principle at the national scale: public investment in early-stage research, generating open-access data, reduces risk for the entire industry.

For developing countries, this translates to a clear priority: invest in resource assessment, exploratory drilling, and subsurface data compilation before seeking private

investment for production development. Every dollar spent on pre-competitive data typically saves five to ten dollars in subsequent development costs, estimated by the authors.

Takeaway 3: Financing Follows Credible Data

Across all case studies, the transition from public or concessional financing to commercial project finance is triggered by credible resource data. Lenders and investors do not require certainty; they require sufficient evidence to quantify risk. The sequence of data milestones identified in Section 6.3 provides a practical roadmap for any country seeking to mobilize private capital for geothermal development.

Takeaway 4: Technology Transfer Is a Multiplier

The most significant factor in the recent acceleration of EGS performance, demonstrated most clearly at Fervo Energy's Project Red, is the application of oil and gas drilling technologies to geothermal contexts. Horizontal drilling, multi-zone hydraulic fracturing, and distributed fiber-optic sensing have each been applied from oil and gas to geothermal with transformative effect.

For CEM countries with significant oil and gas sectors, this represents an immediate opportunity: The drilling expertise, supply chains, and subsurface data of the oil and gas industry are directly applicable to geothermal development. Facilitating this technology transfer, through regulatory frameworks, training programs, and industry partnerships, should be a priority.

Takeaway 5: Policies and regulations that specifically address geothermal can foster successful deployment

No case study in this series achieved large-scale commercial development without a clear, stable, and supportive policy framework. The critical policy elements, documented across Iceland, Indonesia, the Philippines, El Salvador, and others, are:

1. A dedicated geothermal legal framework that clearly defines resource ownership, permitting pathways, and developer rights
2. Long-term power purchase agreements or feed-in tariff mechanisms that provide revenue certainty
3. Grid access commitments that prevent geothermal projects from being displaced by cheaper intermittent resources
4. Community benefit sharing frameworks that build social support

Takeaway 6: Multiple Pathways Can Scale Geothermal

The diversity of technologies represented in this Case Study Series—from mature hydrothermal fields to closed-loop systems in sedimentary basins to frontier superhot rock development—underscores a fundamental insight: there is no single pathway to scaling geothermal. Different countries, different geologies, and different development stages call for different approaches.

The GeoFuture Initiative's contribution is to ensure that decision-makers across CEM member countries have access to the full range of evidence, across technologies, contexts, and development stages, to identify the pathway that is right for them.

Section 8:

Enabling Conditions and Pathways to Scale

Translating the lessons of individual case studies into system-wide deployment requires attention to the enabling conditions that allow geothermal projects to move from exploration to commercial operation

at scale. This section synthesizes the enabling conditions identified across case studies and identifies three primary scaling pathways for CEM member countries.

8.1 Enabling Conditions Framework

ENABLING CONDITION	DESCRIPTION AND CASE STUDY EVIDENCE	ENABLING CONDITION	DESCRIPTION AND CASE STUDY EVIDENCE
Clear legal and regulatory framework	Dedicated geothermal law (e.g., Indonesia model); streamlined permitting; defined surface rights and environmental requirements. Critical enabler in all case studies where large-scale deployment was achieved.	Creditworthy offtake structures	Long-term power purchase agreements with creditworthy off-takers (utilities, state power companies, or large commercial buyers power purchase agreements) are the single most important enabler of commercial project finance.
Public risk-sharing mechanisms	Government-backed exploration drilling, resource risk insurance, or first-loss tranches in project finance. Essential for early-stage development. Demonstrated in Iceland (state investment), Indonesia (Pertamina co-investment), and USA (DOE Utah FORGE program).	International cooperation and knowledge sharing	The GeoFuture Initiative, International Energy Agency, and NLR international partnerships all reduce duplication of effort and accelerate learning. Open-data approaches such as Utah FORGE and Soultz-sous-Forêts, are particularly valuable.
Subsurface data availability	Pre-competitive geophysical surveys, temperature gradient maps, and open-access borehole data. Open source tools, data repositories, user facilities, and/or field testbeds, subsurface tools, and national geological surveys all contribute to derisk geothermal development. Countries with oil and gas sector data are at significant advantage.	Social support	Transparent seismic monitoring, water management protocols, and community benefit agreements established early in project development. Berlin's community programs and Hellisheidi's public seismic data illustrate this in mature operating contexts.
Technical and institutional capacity	National expertise in drilling, reservoir engineering, and plant operations. Built over time through training programs, technology transfer from oil and gas, and international partnerships. Philippines and Iceland demonstrate multi-decade capacity development.		

8.2 Three Potential Pathways to Scale

Based on case study evidence, three primary pathways for scaling geothermal deployment are identified for CEM member countries to consider:

Pathway 1: Public-Led Exploration and De-Risking

Governments fund early-stage exploration drilling, subsurface data acquisition, and pilot testing. Private developers are invited to participate in subsequent phases with access to public data. This model, demonstrated at Utah FORGE in the USA and in national exploration programs in Iceland, is most appropriate for countries with promising resources but limited private sector track record in geothermal.

Pathway 2: Pilot-to-Commercial Transition

Private developers, supported by concessional finance and regulatory clarity, develop pilot projects that validate technology and resource before scaling to commercial development. Fervo Energy's progression from Project Red to Cape Station exemplifies this pathway. International development finance institutions, such as the World Bank, International Finance Corporation (IFC), and Asian Development Bank (ADB), can play a critical role in providing the patient capital and technical assistance needed to bridge the pilot-to-commercial gap.

Pathway 3: Mature Field Optimization and Life Extension

Countries with existing hydrothermal fields, including several CEM member countries, can deploy stimulated reservoir activities (hydraulic, acid, cold-water, chemical stimulation) to extend field life, restore declining production, and improve economics. The Los Azufres, Berlin, Hellisheidi, and Sumikawa case studies all demonstrate elements of this pathway. This is often the fastest and lowest-cost route to near-term geothermal capacity additions.

Conclusion

Next-generation geothermal technologies are advancing from experimental concepts to commercially viable energy solutions with a meaningful role in global energy markets. The 13 case studies presented in this series collectively demonstrate that:

1. **The technical barriers** to EGS, closed-loop, and superhot rock development are being overcome, driven by technology transfer from oil and gas, open-data research programs, and iterative commercial deployment.
2. **The economic barriers** are declining on a learning-curve trajectory, particularly as drilling costs fall with oil and gas technique adoption.
3. **The financing barriers** are addressable through structured risk-sharing, and public investment in exploration and pilot phases reduces the risk premium required by private capital, enabling project finance on increasingly commercial terms.
4. **The policy and/or regulatory barriers** are well understood and tractable, and countries that have implemented dedicated geothermal law, streamlined permitting, and offtake security have achieved faster and more cost-effective deployment.

The GeoFuture Initiative exists to accelerate the deployment of next-generation geothermal technologies for CEM member countries. Through knowledge sharing, technical assistance, and facilitated access to international financing, the Initiative is committed to helping countries move along the decision pathway from resource assessment to commercial geothermal power at scale.

CEM invites all member countries to engage with the findings of this series, contribute their own case studies, and work with the GeoFuture Initiative team to identify the geothermal development pathway most appropriate for their national context. The next generation of geothermal energy is here. Together, we can make it happen.

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