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The Future of Geothermal Energy

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Abstract

This special report focuses on geothermal, a promising and versatile renewable energy resource with vast untapped potential for electricity generation, heating and cooling. Geothermal has been a part of energy systems for more than 100 years, but it has played a limited role on a global scale. Now, the geothermal industry is at a critical juncture.

New technologies are enabling access to previously untapped resources, while cost reductions and innovative financing models are paving the way for increasing geothermal's role in energy systems around the world. Additionally, techniques developed by the oil and gas industry – including a strong understanding of the subsurface, drilling and completing wells, predicting fluid flows and managing large-scale projects – can rapidly drive down costs and help tap geothermal resources deeper in the ground.

However, to successfully scale up geothermal energy, a number of challenges need to be addressed, including project development risks, permitting and licensing processes, environmental concerns and social acceptance. This report quantifies the technical and market potential of next-generation geothermal and suggests measures that could help reduce risks, accelerate innovation and increase the bankability of conventional and next-generation projects, allowing for wider geothermal uptake.

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Table of contents

Executive summary

Technology breakthroughs are unlocking huge potential for geothermal energy

Advances in technology are opening new horizons for geothermal, promising to make it an attractive option for countries and companies all around the world. These techniques include horizontal drilling and hydraulic fracturing honed through oil and gas developments in North America. If geothermal can follow in the footsteps of innovation success stories such as solar PV, wind, EVs and batteries, it can become a cornerstone of tomorrow's electricity and heat systems as a dispatchable and clean source of energy. For the moment, geothermal meets less than 1% of global energy demand and its use is concentrated in a few countries with easily accessible and high-quality resources, including the United States, Iceland, Indonesia, Türkiye, Kenya and Italy.

With continued technology improvements and reductions in project costs, geothermal could meet up to 15% of global electricity demand growth to 2050. This would mean the cost-effective deployment of as much as 800 GW of geothermal power capacity worldwide, producing almost 6 000 terawatt-hours per year, equivalent to the current electricity demand today of the United States and India combined.

Geothermal is a versatile, clean and secure energy source

Geothermal can provide around-the-clock electricity generation, heat production and storage. As the energy source is continuous, geothermal power plants can operate at their maximum capacity throughout the day and year. On average, global geothermal capacity had a utilisation rate over 75% in 2023, compared with less than 30% for wind power and less than 15% for solar PV. In addition, geothermal power plants can operate flexibly in ways that contribute to the stability of electricity grids, ensuring demand can be met at all times and supporting the integration of variable renewables such as solar PV and wind.

The potential for geothermal is now truly global

The full technical potential of next-generation geothermal systems to generate electricity is second only to solar PV among renewable technologies and sufficient to meet global electricity demand 140-times over. This is a key finding of first-of-a-kind analysis of geothermal potential conducted for this report in collaboration with Project InnerSpace. Geothermal energy potential increases as developers access higher heat resources at greater depths. New drilling technologies exploring resources at depths beyond 3 km open potential for geothermal in nearly all countries in the world. Using thermal resources at depths below 8km can deliver almost 600 TW of geothermal capacity with an operating lifespan of 25 years.

Geothermal can also provide a continuous source of low- and medium-temperature heat for use in buildings, industry and district heating. Global geothermal potential from sedimentary aquifers at depths up to 3 km and temperatures greater than 90°C is estimated around 320 TW. This is consistent with the requirements of existing fossil fuel-fired district heating networks, which could be decarbonised by switching to geothermal heat. For lower temperature requirements, the potential for geothermal increases about tenfold.

The technical potential of geothermal would be more than enough to meet all electricity and heat demand in Africa, China, Europe, Southeast Asia and the United States. Geothermal holds particular promise in markets with rapidly rising electricity demand by complementing output from other low-emissions technologies such as renewables and nuclear power while also bolstering energy security.

Investment in geothermal is growing

Governments, oil and gas companies and utilities are among those looking for investment opportunities in geothermal. If deep cost reductions for next-generation geothermal can be delivered, total investment in geothermal could reach USD 1 trillion cumulatively by 2035 and USD 2.5 trillion by 2050. At its peak, geothermal investment could reach USD 140 billion per year, which is higher than current investment in onshore wind power globally. As a dispatchable source of clean power, geothermal is also attracting interest from stakeholders beyond the energy industry, including technology companies looking to meet the fast-growing demand for electricity in data centres.

The market potential for next-generation geothermal is spread around the world

Cost-competitive geothermal would offer a much-needed source of dispatchable low-emissions electricity to markets around the world. Rising awareness of the potential for geothermal comes at a time when global electricity demand growth is set to accelerate due to both conventional uses, such as cooling, and newer ones, such as electric vehicles and data centres. The availability of geothermal would be particularly valuable to bolster electricity security in regions looking to transition away from coal-fired power, such as China, India and Southeast Asia, or to complement large amounts of solar PV and wind in regions such as Europe and the United States. China, the United States and India have the largest market potential for next-generation geothermal electricity, together accounting for three-quarters of the global total.

The oil and gas industry can play a key role in boosting the cost-effectiveness of geothermal

Up to 80% of the investment required in a geothermal project involves capacity and skills that are common in the oil and gas industry. The industry has transferable skills, data, technologies and supply chains that make it central to the prospects for next-generation geothermal. Diversifying into geothermal energy could be of great benefit to the oil and gas industry, providing opportunities to develop new business lines in the fast-growing clean energy economy, as well as a hedge against commercial risks arising from projected future declines in oil and gas demand.

Technologies and resources are available but cost reductions are crucial

Policy and innovation support, together with the expertise of the oil and gas sector, can help to bring down costs for new next-generation geothermal projects to levels that make it one of the cheapest dispatchable sources of low-emissions electricity. Costs for next-generation geothermal are relatively high today compared with other low-emissions technologies. But engagement from policymakers and the oil and gas industry can lead to a significant fall in geothermal costs as new projects are commissioned, as has been proven possible by the rapid cost reductions for solar PV, batteries and EVs over the past decade. We estimate that, with the right support, costs for next-generation geothermal could fall by 80% by 2035. At that point, new projects could deliver electricity for around USD 50 per megawatt-hour, which would make geothermal one of the cheapest dispatchable sources of low-emissions electricity, on a par or below hydro, nuclear and bioenergy. At this cost level, next-generation geothermal would also be highly competitive with solar PV and wind paired with battery storage.

Challenges related to permitting and environmental impacts need to be addressed

Permitting and administrative red tape mean that it can take up to a decade to commission a new geothermal project: a renewed effort to simplify project development while maintaining high environmental standards will be essential. Governments could simplify permitting processes by consolidating and accelerating administrative steps involved. Governments could also consider dedicated geothermal permitting regimes separate from minerals mining. Policies and regulations enforcing robust environmental standards are critical for the responsible development of geothermal projects.

Delivering widespread and competitive geothermal will require specialised labour

The geothermal industry provides around 145 000 jobs today and geothermal employment could rise more than sixfold to 1 million by the end of this decade, but there is a risk of a skills shortfall. Many people working in geothermal today came from the oil and gas sector, and future geothermal developments will hinge on having a skilled, appropriately sized workforce. Enrolments in degree programmes traditionally associated with the fossil fuel industry have fallen in many advanced economies in recent years and this could have knock-on implications for geothermal developments. Further support for university degrees, apprenticeships, training programmes, and regional and international centres of excellence is needed.

Government support is needed to encourage investment and help reduce costs of next generation geothermal

Policy support is lagging: more than 100 countries have policies in place for solar PV and/or onshore wind, but less than 30 have implemented policies for geothermal. If geothermal is to realise its potential, governments need to move it up the national clean energy policy agenda with specific goals and roadmaps and recognise its unique features as a source of firm, dispatchable low-emissions electricity and heat. Along with support for innovation and technology development, governments could design policies that de-risk project development. These could include policies focusing on risk mitigation measures at the early project development phase and on contracts ensuring long-term revenue certainty.

Policy recommendations

- **Move geothermal up the energy policy agenda** by making geothermal energy more prominent in national energy planning; developing dedicated goals and technology roadmaps; and recognising the unique features of geothermal as a source of firm, dispatchable low-emissions electricity and heat.
- **Design risk mitigation schemes for early-stage project development,** including in collaboration with regional, national and international finance institutions.
- **Introduce policies ensuring long-term revenue certainty and fair remuneration** through long-term contracts and support schemes that properly compensate for contributions to system adequacy and flexibility.
- **Simplify and streamline permitting for geothermal energy** by consolidating and accelerating administrative steps involved. Consider dedicated geothermal permitting regimes separate from minerals mining.
- **Design policies and regulations enforcing robust environmental and social safeguards** by actively engaging communities.
- **Support geothermal heat applications for residential, commercial and industry use** by investing in heat demand mapping, energy system planning, district network infrastructures and by financing at national, regional and city levels.
- **Improve data quality and create open data repositories** to facilitate geothermal resource assessments for investors.
- **Expand geothermal-specific research and innovation programmes** including demonstration and testing of emerging technologies.
- **Increase policy focus on expanding geothermal skillsets to meet growing demand for workforce** by increasing the number of geothermal-specific academic programmes and trainings in partnership with academia and industry.
- **Promote international collaboration to develop technical standards for geothermal** to address environmental concerns and enable scalability for achieving economies of scale.

Introduction

This special report focuses on geothermal energy, a promising and versatile renewable energy resource with vast untapped potential for electricity generation, heating and cooling.

Geothermal energy is the thermal (heat) energy derived from the Earth's subsurface. Part of this energy is residual heat generated during the planet's formation (i.e. from planetary accretion and the decay of short-lived radioactive isotopes) more than 4 billion years ago. The rest originates mostly from the continuous and spontaneous radioactive decay of naturally occurring isotopes (e.g. uranium 238 and 235, thorium 232 and potassium 40) within the Earth's core and mantle, which maintains the core temperature at around 5 000°C. This heat from the core and mantle is transferred to the Earth's surface through conduction (heat passing through materials) as well as convection and advection mechanisms (heat being transported by a moving fluid – e.g. magma), resulting in a continuous heat flow of about 45 TW across the surface of the globe.

Another portion of the Earth's thermal energy comes from solar radiation at the surface and from ambient heat absorbed and accumulated over millennia, which influences the temperature of soil, bedrock and water at shallow depths everywhere on Earth.

The temperature difference between the Earth's core and surface induces a temperature gradient in the crust: on average, the temperature increases 25-30°C per kilometre of depth. However, geothermal heatflows and temperature gradients are unevenly distributed and are strongly linked to tectonic conditions, including volcanic activity at spreading centres, rift zones, subduction zones and hot spots, as well as crustal extension (with thinner crust). These circumstances can lead to regionally elevated temperatures in the crust, and temperatures can also be higher in areas with extensive sediment-covered granitic intrusions, due to heat produced from radioactive decay.

Geothermal energy systems harness this heat from the subsurface and transport it to the surface, where it can be used for heating and cooling, electricity generation and energy storage.

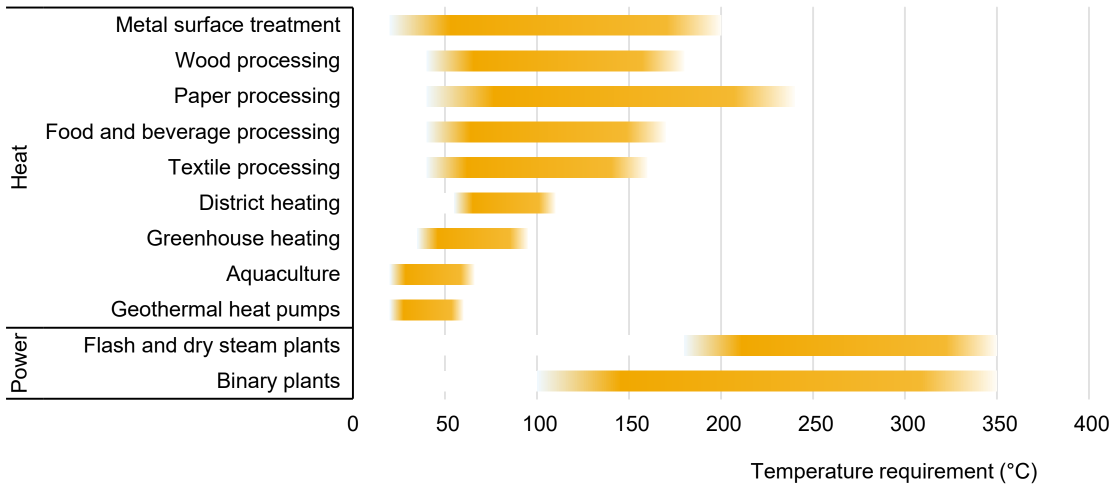
Geothermal heat can be carried to the surface by fluids naturally occurring in the subsurface in specific geological settings such as aquifers, where water trapped in porous or fractured rock beneath a layer of relatively impermeable caprock forms a reservoir and is heated by the surrounding rock. Temperature, fluid and rock permeability conditions define hydrothermal resources. The systems used to exploit these hydrothermal reservoirs are what this report refers to as **conventional geothermal technologies.**

Efforts to overcome dependency on location-specific hydrothermal resources have led to the development of new approaches that harvest heat at greater depths by circulating a fluid from the surface through engineered systems, either through fractured rock or in closed-loops circuits, sometimes in areas that have no preexisting hydrothermal reservoir.

These approaches, also termed reservoir-independent, are more recent and generally less mature. This report therefore refers to them as **next-generation geothermal technologies.** Overall, they include enhanced geothermal systems (EGSs) and closed-loop geothermal systems (CLGSs), with the latter sometimes also referred to as advanced geothermal systems (AGSs).

In addition, low-temperature heat can be transferred from and to the near-surface (<100m of depth) using **ground-source heat pumps** – also called **geothermal heat pumps** – to supply a variety of applications with low- and medium-temperature heat (generally below 200°C) or cooling.

Temperature requirements for possible geothermal energy applications



Sources: IEA analysis based on data from Arpagaus, C. et al. (2018), High Temperature Heat Pumps; US DOE (2019), GeoVision.

Unlike for other renewable energy sources such as wind, solar and hydro, geothermal energy production does not depend on climatic conditions or seasonality. It can be used in direct applications (for space and water heating and cooling, or for industrial processes) or for electricity generation, with different technologies (e.g. binary, flash and dry steam plants[1]) depending on the geothermal resource conditions (temperature, pressure of the reservoir) and properties (e.g. reservoir geology, permeability/porosity, heat transfer conditions); the chemical properties of the fluid; and whether the fluid is in vapor or liquid phase in the system.

However, several challenges must be addressed to successfully scale up geothermal energy development. This report presents these obstacles and highlights policy strategies, measures and actions that stakeholders could take to help spur geothermal deployment and realise its potential contribution to low-carbon energy systems in upcoming decades.

The first chapter of this report summarises the state of conventional geothermal energy development worldwide, its current role in final energy consumption for heating and cooling as well as electricity generation, and the policy and market environment. It also presents untapped potential and provides the IEA's conventional geothermal outlook for power generation and heat.

The second chapter introduces recent technology innovations in geothermal energy systems – what this report refers to as next-generation geothermal – and explores how these innovations could technically unlock substantial energy resources. It describes an assessment of this new technical potential for power and heat applications and discusses remaining technical challenges and ongoing research to overcome them.

In the third chapter, we highlight how the oil and gas sector could contribute to low-carbon energy transitions by leveraging its extensive resources and its long-term expertise and knowhow to support and accelerate geothermal development, while diversifying its activity. This chapter discusses competencies and overlaps between the oil and gas and geothermal industries, assesses the potential cost reductions achievable through expertise and technology transfers, and explores the implications in terms of skill development and worker opportunities.

Next, the fourth chapter delves into the cost competitiveness of next-generation technologies, explores their future market potential and provides a global and regional outlook for power and direct-use applications, including industrial heat and district heating. It also discusses how geothermal energy storage could

[1] Geothermal power plants use heat from the geothermal fluid to power a turbine that turns a generator to produce electricity. The heat-depleted geothermal fluid is then reinjected into the reservoir, where it collects heat again. Binary-cycle power plants circulate the geothermal fluid through a heat exchanger to heat and vaporise a second fluid that flows through the turbine to produce electricity (generally using a closed-loop Rankine cycle). Flash steam power plants process the geothermal fluid to separate steam from water, before flowing the steam through the turbine to generate electricity. Dry steam power plants inject geothermal steam that is above the saturation point of water directly into the turbine to generate electricity, without needing to separate water from steam. Binary plants can operate with fluids at lower temperatures than flash and dry steam plants (from ~95°C versus more than ~180°C), but they also have lower conversion efficiencies and generally higher investment costs.

enhance power system flexibility and describes possible geothermal system opportunities for (and contributions to) lithium production.

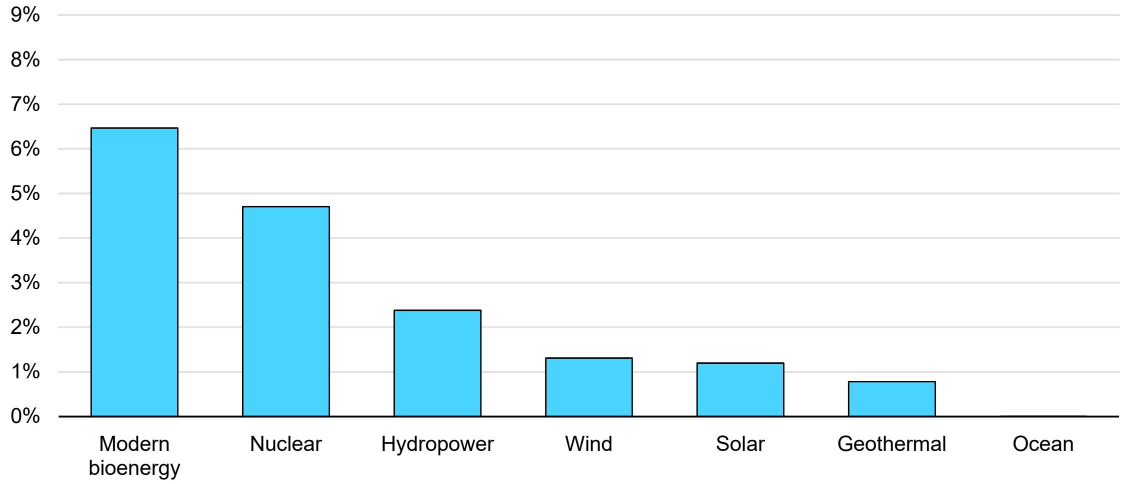
Finally, the fifth chapter discuss challenges to faster geothermal energy development and provides policy examples, suggestions and recommendations.

Chapter 1: Conventional geothermal

Total geothermal energy use

Geothermal energy is directly used to heat and cool buildings (space and water), including through district heating networks, as well as for electricity generation. Geothermal technologies also have considerable energy storage potential. In 2023, geothermal energy use reached 5 exajoule (EJ), accounting for almost 0.8 % of global energy demand. Among clean energy sources, modern bioenergy makes up almost 7% of global energy demand, while the shares of others such as hydropower, nuclear, wind and solar range from 1% to 3% each. Today, geothermal remains the second least-used clean energy source after ocean energy.

Shares of clean energy technologies in total energy demand, 2023



Notes: Values exclude geothermal heat harnessed by ground-source heat pumps, which is not included in official IEA statistics. However, estimates of geothermal heat from ground-source heat pumps derived from modelling are included in the heat discussion below, as well as in the outlook section. "Modern bioenergy" includes all bioenergy in the form of liquids (ethanol, biodiesel and biojet fuel), gases (biogas and biomethane) and solids, excluding the traditional use of solid bioenergy such as a three-stone fire or basic improved cook stoves (ISO tier < 3), often with no or poorly operating chimneys.

Source: IEA (2024), World Energy Balances.

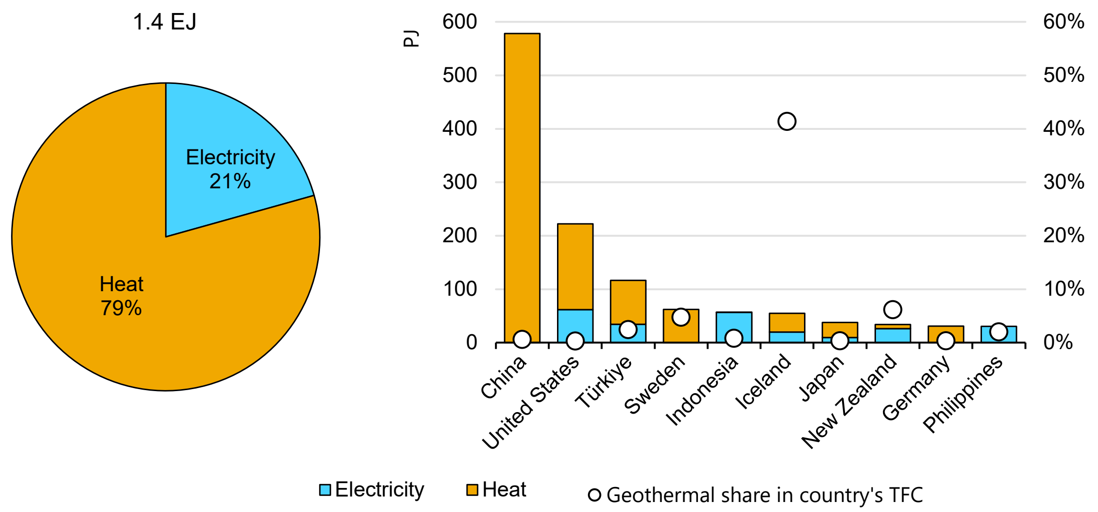
Globally, the consumption of electricity from geothermal accounts for more than one-fifth of total geothermal final energy consumption. District heating networks and ground-source heat pumps consume the remainder to heat and cool space and/or water in residential and commercial buildings, including tourism/wellness facilities (e.g. for bathing and swimming), greenhouses and aquaculture ponds; to dry agricultural crops; and to supply process heat to industry, in addition to other applications.

While geothermal energy is used for heating/cooling and electricity in more than 40 countries today, the 10 largest consumers – People's Republic of China (hereafter "China"), the United States, Türkiye, Sweden, Indonesia, Iceland, Japan, New Zealand, Germany and the Philippines – together account for almost 90% of the global total.

Iceland has the highest share, meeting almost half its final energy consumption with geothermal resources because they are highly available and the country's policies have supported continuous exploration, drilling and project development since the 1920s. Next, China is responsible for almost half of global geothermal final energy consumption, using it exclusively for space heating, followed by the United States.

In Türkiye, geothermal final energy use is divided between electricity and heating, used mostly in the agriculture and tourism/wellness sectors, while in Sweden and Germany, ground-source heat pumps dominate consumption. In other major markets, including New Zealand, the Philippines and Italy, most geothermal energy is used in the form of electricity.

Total final geothermal energy consumption by application, world (left), and top 10 consuming countries (right), 2023



Notes: TFEC = total final energy consumption. EJ = exajoule. PJ = petajoule. Heat consumption includes an estimate for ground-source heat pumps that is not included in IEA direct heat consumption statistics.

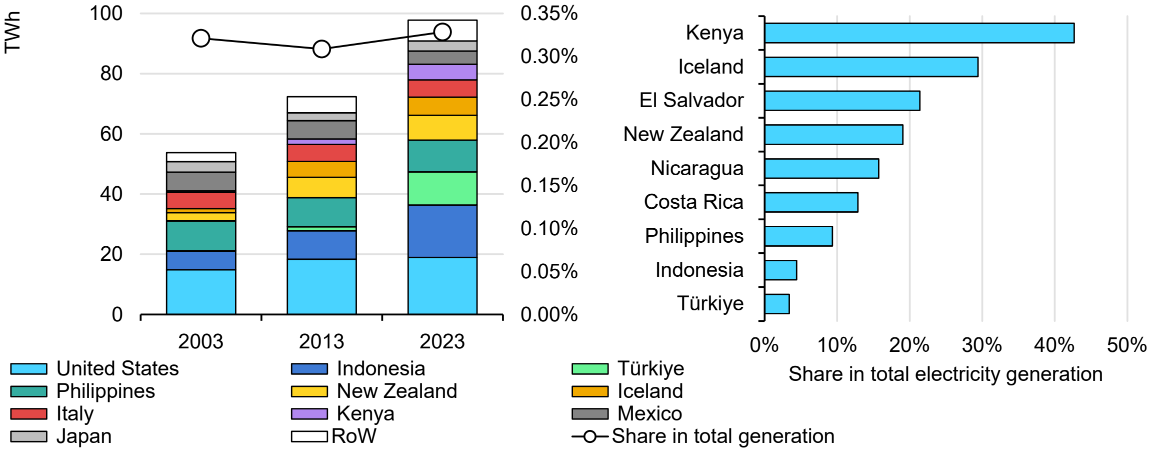
Sources: IEA (2024), World Energy Balances; IEA (2024), World Energy Outlook 2024.

Electricity generation

The first successful generation of electricity from geothermal energy took place in Italy in 1904, followed in 1913 by development of the first commercial geothermal power plant (Larderello 1), with its 250-kilowatt (kW) capacity powering the railway system and villages in the area. Around thirty other countries have since developed geothermal power production, with annual worldwide generation almost doubling in the past two decades to just below 100 terawatt-hour (TWh) in 2023 – 0.3% of total global electricity generation and just above 1% of global renewable electricity supply.

In 2023, the United States, Indonesia, Türkiye, the Philippines and New Zealand together accounted for two-thirds of global geothermal electricity generation, with Iceland, Italy, Kenya, Mexico and Japan contributing another 25%. While its share in total electricity generation is marginal in most regions, geothermal plays a major role in the power systems of Kenya, Iceland, El Salvador, New Zealand, Nicaragua and Costa Rica, where its contribution exceeds 10% of total electricity supply.

Geothermal electricity generation, 2003-2023 (left) and geothermal shares in selected countries' electricity supplies, 2023 (right)



Note: RoW = rest of world.

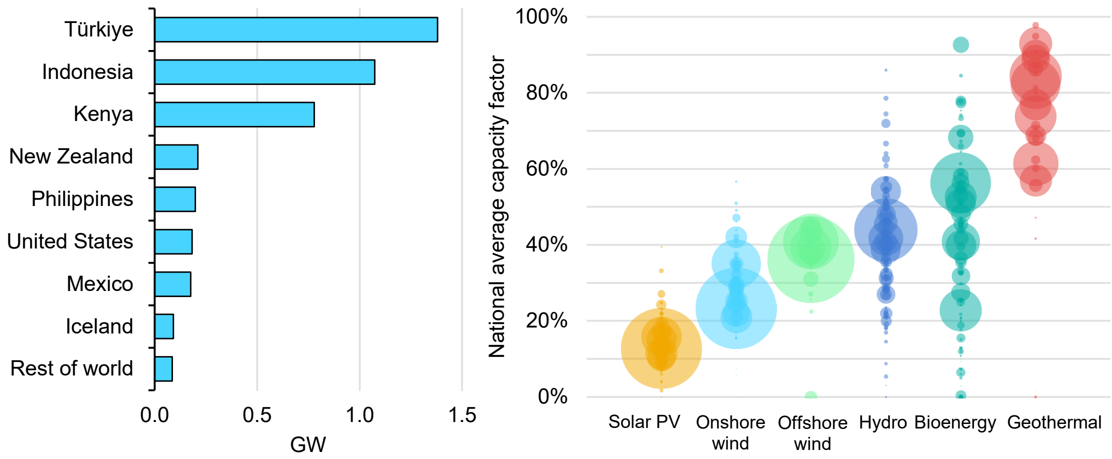
Source: IEA (2024), World Energy Balances.

Global geothermal power capacity increased almost 40% over the past decade to nearly 15 gigawatt (GW) in 2023. During this period, Türkiye, Indonesia and Kenya accomplished the largest developments, accounting for more than three-quarters of new capacity additions. Despite recent growth from emerging markets and developing economies, the United States still has the largest installed geothermal power capacity worldwide, built mostly between 1980 and 1995.

Geothermal power plant utilisation hours, or capacity factors, are relatively high compared with those of other renewable energy sources. In 2the last decade, the global geothermal fleet's capacity factor averaged 75-80%, with national averages for certain years exceeding 90% in countries such as New Zealand, Iceland, Italy and Ethiopia.

A typical geothermal power plant can produce five to six times more energy than a solar PV plant with similar installed capacity (typically with a 10-15% capacity factor). Coal and combined-cycle natural gas power plants can reach similar capacity factors as geothermal facilities, but their global average utilisation rates are lower (around 60% and 50% respectively), as some plants adapt their output to daily (or seasonal) demand profiles and variable renewable power generation. Overall, geothermal power plants can provide dispatchable renewable electricity that can help integrate variable solar PV and wind.

Geothermal net power capacity additions in leading countries, 2013-2023 (left) and capacity factors for renewable electricity sources (right)



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Notes: Capacity factors are five-year national averages (2019-2023). Bubble size is proportional to country shares in global installed capacity for each technology. Capacity factors describe average output for the year relative to maximum rated power capacity.

Heat and cooling

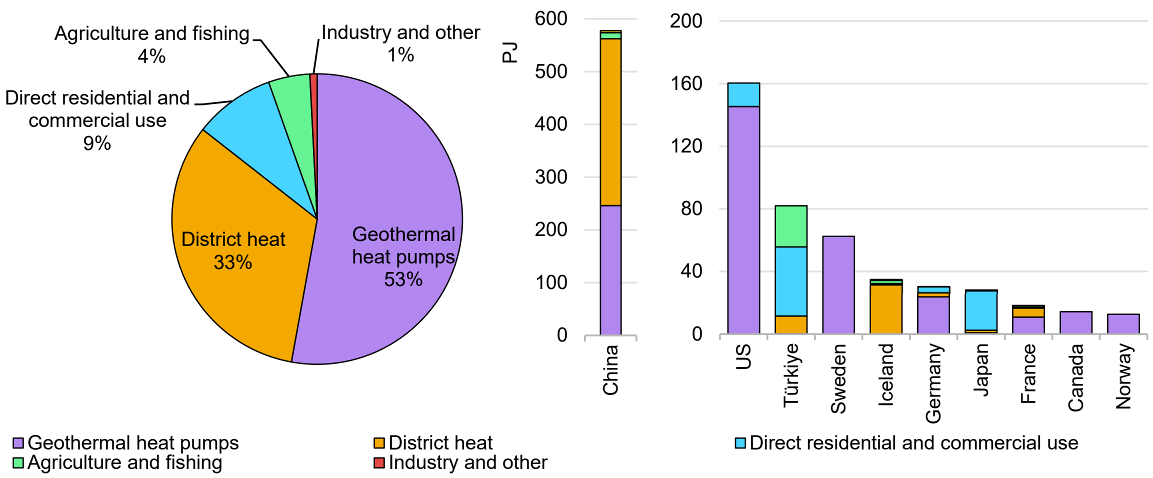
Today, geothermal energy meets around 1% of heat demand in buildings globally, with a very limited role in industry. Over 60% of geothermal heat (1.1 exajoule [EJ]) is consumed in residential and commercial buildings, either through ground-source (geothermal) heat pumps (which provide heating and cooling to residential and commercial facilities by transferring heat from – and to – the ground at shallow depth) or by direct heat delivery from medium depth. Geothermal energy use in buildings also includes tourism/wellness sector consumption, for instance at hot springs for thermal bathing.

It is estimated that ground-source (geothermal) heat pumps supply about half of all geothermal heat consumed.[2] Today they are being deployed mostly in China, the United States, Sweden, Switzerland, Germany, France, Canada and Norway owing to incentives or public programmes that promote heat pump technologies in general. Considering the large amount of easily accessible low-temperature resources that can be harnessed by ground-source (geothermal) heat pumps for heating and cooling, their potential remains largely untapped in most locations.

High initial investment costs compared to other residential and commercial heating and cooling options and temporary disruptions during their installation – which can represent half of the total installation cost – limit their deployment in many markets, especially when technology-specific policy support is not available. However, these high initial investment costs should be weighed against potential infrastructure savings. Utility-financed geothermal networks can address these barriers to enable mass market deployment.

District heating networks[3] are the second-largest geothermal heat application, accounting for one-third of its global final consumption. Almost all of Iceland's district heat production (over 90%) is fuelled by geothermal energy, making it the country's largest geothermal heat application thanks to particularly favourable geological conditions.

Direct and indirect geothermal energy consumed for heating and cooling by application, world (left) and top 10 consumers (right), 2023



Note: "Direct residential and commercial use" includes space and water heating, bathing and swimming, and snow-melting.

[2] As ground-source heat pumps are not included in IEA statistics and energy balances, estimates are based on sales and installation data.
[3] District heating systems can also use ground-source (geothermal) heat pumps.

China is the largest user of geothermal district heating worldwide, accounting for two-thirds of the total, with extensive district network infrastructure in its Eastern and Northern provinces stemming from policies supporting the decarbonisation of heating. Nevertheless, geothermal represents just 4% of the country's district heat supply, which is dominated by coal. In Europe, geothermal energy provides less than 3% of district heating, but countries have been offering stronger policy support since 2022 as a result of energy security concerns arising from the energy crisis.

Only 4% of all geothermal energy consumed is used in the agriculture and fishing sectors, with Türkiye's greenhouses dominating these applications. Meanwhile, industrial use of geothermal heat remains very limited globally, representing just 1% of direct use, concentrated mostly in China and New Zealand (96% of the global total), where it is used for various industrial processes. While geothermal energy can meet low-temperature process heat needs, its use remains limited due to high investment costs compared with fossil fuel alternatives, as well as by the availability and relative ease of deploying other low-carbon alternatives (such as electrification) and of using bioenergy wastes and residues that are readily available in some subsectors (e.g. paper and pulp).

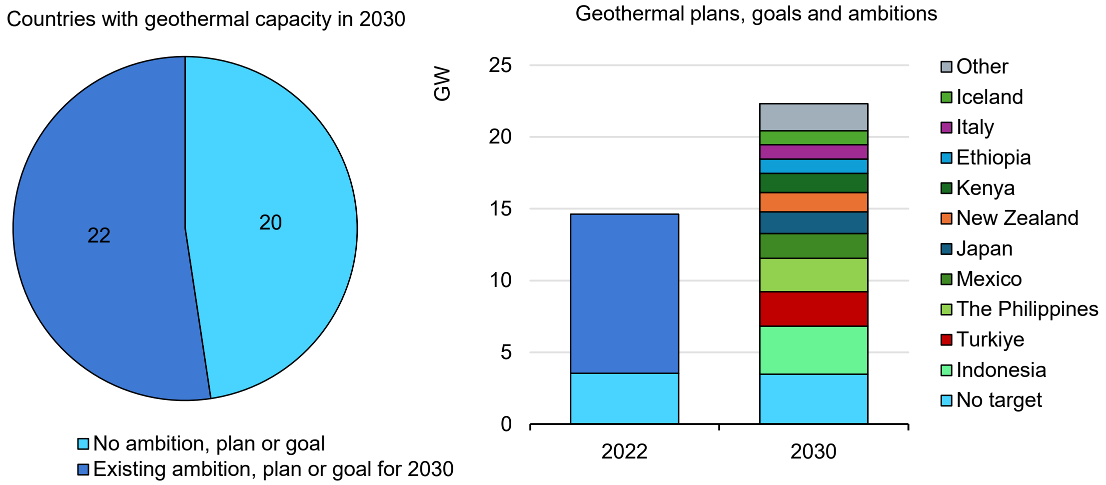
Policy

Government plans and ambitions

More than thirty countries currently have geothermal power capacity installed, with this number increasing to 42 by 2030. However, only 22 countries have included geothermal energy in their renewable energy goals for 2030. The combined geothermal-specific goals of these countries total 19 GW, a 30% increase from current geothermal capacity.

Indonesia, the Philippines and Türkiye together have the most ambitious announced goals. These three countries collectively aim to expand their geothermal capacity by more than one-third followed by Mexico, Japan and New Zealand. However, a country-by-country analysis shows that geothermal is also expected to expand in countries that have no announced ambition or government plan, including the United States, El Salvador, Costa Rica, Germany and France. In fact, the US Department of Energy's GeoVision analysis explores geothermal potential in a variety of scenarios that consider technology development, market conditions and barriers, demonstrating a potential of 90 GW by 2050.

Government plans, goals and ambitions for geothermal power capacity in 2030



Note: Left figure numbers include three regional aggregates, accounted as single countries. Actual number of countries may be larger than indicated.

Sources: IEA (2024), COP28 Tripling Renewable Capacity Pledge; IEA (2024), Renewables 2024.

For heat, only few countries currently include geothermal as a viable heating and cooling option in their government ambitions, plans and modelling. For those that do, geothermal energy is often harnessed through district heating systems or geothermal heat pumps.

However, several EU member states have recognised the potential of geothermal technology in their National Energy and Climate Plans (NECPs), highlighting its ability to increase the share of renewables in final energy consumption while enhancing energy security. Austria, Ireland, the Netherlands, Poland, Croatia, France, Hungary and Germany have therefore adopted geothermal roadmaps and ambitions for their heating and cooling sectors. Furthermore, at the city level, many localities across Europe are considering using geothermal applications to decarbonise their heating and cooling demand.

Incentives and remuneration

While more than 100 countries have policies in place for solar PV and/or onshore wind, less than 30 have implemented policies for geothermal power. These policies fall into two categories: risk mitigation schemes, which focus on reducing resource risks before a power plant is built, and remuneration schemes, which address revenue risks during a plant's operation.

Numbers of countries with policies in place

Technology	Risk mitigation schemes	Remuneration schemes
Solar PV, onshore wind	44	101
Offshore wind	13	22
Geothermal	27	28

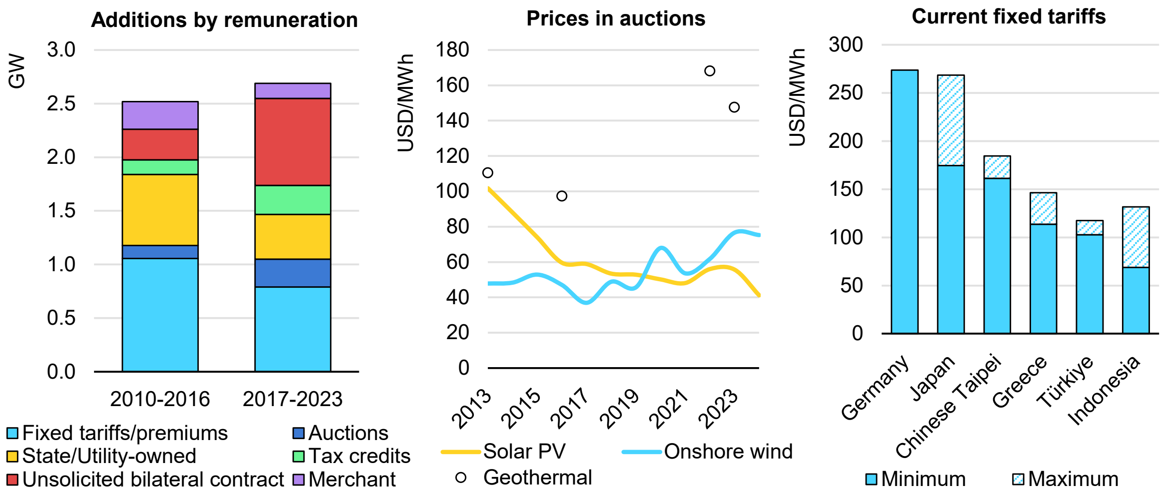
Notes : In addition to the national risk mitigation schemes counted here, regional schemes exist covering several countries, for instance the Geothermal Risk Mitigation Facility (GRMF) which is eligible in 13 countries in East Africa or the Geothermal Development Facility for Latin America which provides support in 11 countries.

Sources: IEA analysis based on data from REN21 (2024), Renewables 2024 Global Status Report: Energy Supply; REN21 (2023), Renewables 2023 Global Status Report: Energy Supply data pack, ESMAP (2024), Activities grouped by "Thematic/Cross-Cutting and Priorities", Duma, D., Muñoz Cabré, M., & Kruger, W. (2023), Risk mitigation and transfer for renewable energy investments: Case studies in the Southern Africa Development Community

In contrast with other renewable energy sources, geothermal projects are vulnerable to notable resource risks during project development, i.e. the risk of not finding geothermal resources with appropriate qualities (temperature, flowrate) for the planned surface application. These risks could be further exacerbated by high exploration and drilling costs.

To address these risks, 27 countries have introduced risk mitigation schemes. Depending on a market's maturity, instruments can include grants for drilling, subsidised loans and public and/or private insurance schemes to cover resource risks. Public (and/or private) resource assessments gained through geophysical and geochemical surveys, such as in France, Germany and the Netherlands, can also mitigate risks significantly.

Overview of incentives for geothermal power development



IEA. CC BY 4.0.

Notes: In the right figure, the solid bar represents the minimum level of fixed tariffs and the striped bar the maximum. Typically, the actual level depends on the project's installed capacity and other factors such as location. MWh = megawatt-hour.

Sources: IEA (2024), Renewables 2024.

The revenue risks of geothermal power plants are usually covered through either policies (e.g. feed-in tariffs) or long-term, market-driven remuneration mechanisms (e.g. corporate power purchase agreements [PPAs]). Motivated by cost competitiveness and policy targets, state-owned or public utilities developed almost all conventional geothermal projects pre-2010. During 2010-2016, the share of geothermal projects commissioned through bilateral power purchase contracts between utilities and private companies increased to around 20%, with much of this capacity developed in the Philippines and Kenya. Since 2010, the use of long-terms contracts with fixed government-set tariffs has increased steadily, mainly owing to policies in Türkiye.

Remuneration for geothermal power is usually higher than for electricity from solar PV and onshore wind plants.[4] For instance, recent auctions in Croatia, Italy, Mexico and the United Kingdom awarded geothermal plant contracts for USD 100-170 per megawatt-hour (MWh) – three to four times higher than for wind and solar PV. While the fixed tariffs set by the governments of Türkiye, Greece, and Japan are similar to recent auction results, Germany offers almost USD 275/MWh for new geothermal electricity projects.

Costs, investment and jobs

Costs

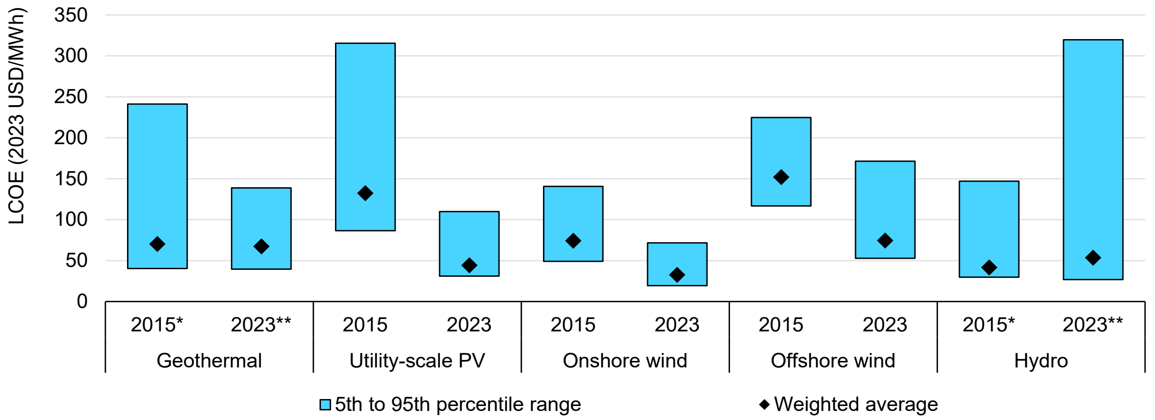
Conventional geothermal power generation costs are site-specific, and lower expenses can be achieved only in certain locations with favourable natural resource availability. As a result, generation costs for plants built during 2010-2023 vary widely, with the estimated levelised cost of electricity (LCOE) ranging from USD 40/MWh to over USD 240/MWh. Costs are highly dependent on the quality of the geothermal resource (i.e. its depth, temperature and flow rate) and rock permeability. In most cases, large projects (100-300 MW) have been developed in the most suitable areas of resource-rich countries such as the Philippines, Indonesia, Kenya, the United States, New Zealand and Türkiye.

As a result, global average annual generation costs reported over the past decade are in the range of USD 60-80/MWh. Indeed, only a limited number of large-scale projects were able to achieve electricity generation costs below USD 80/MWh, comparable with other dispatchable technologies. This value exceeds the LCOE of most solar PV and wind installations. However, geothermal power is a

[4] However, it should be noted that despite higher costs/tariffs, geothermal offers additional value to the system as a dispatchable baseload renewable energy source.

dispatchable technology that can provide many additional services to the energy system, which is not captured in the LCOE methodology (Chapter 3 discusses the value of these additional services).

Typical LCOE range for renewable power technologies, 2015-2023



*Projects commissioned in 2010-2015. **Projects commissioned in 2019-2023.

Sources: IEA analysis based on data from IRENA.

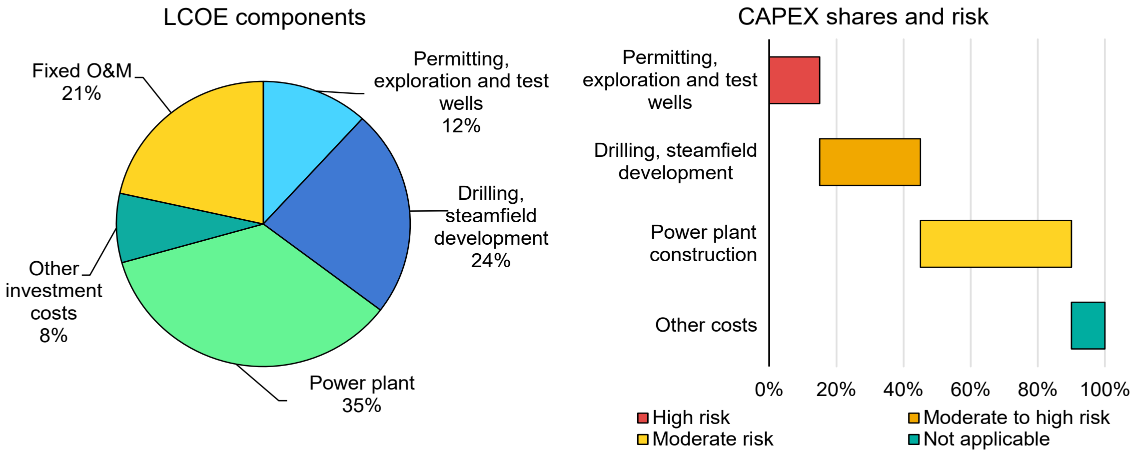
Average costs of conventional geothermal power generation remained stable over the last decade because the need for a location-specific design makes it difficult to achieve economies of scale and standardise equipment. In addition, the geothermal market remains small and the number of equipment manufacturers and service providers is limited, precluding the potential cost savings that result from strong competition.

Initial investment accounts for about 80% of electricity generation costs, with the remainder associated with fixed operations and maintenance (O&M) expenses. O&M expenses for geothermal plants are relatively high due to the necessity of carefully managing production and potentially drilling additional wells to maintain required performance over a project's lifetime.

Power plant equipment and construction accounts for 40-60% of total conventional geothermal investment costs. These costs can vary significantly, depending on the size and complexity of a power plant's configuration. Large, direct-steam and flash plants utilising high-temperature resources typically have the lowest costs per MW, followed by binary, hybrid and other complex designs.

The second-largest item in the investment cost breakdown is production and injection well-drilling and steamfield development, comprising 30-45% of the total conventional geothermal project investment. Geological conditions, resource quality and drilling success rates can vary drastically, impacting overall investment needs.

Typical breakdown of conventional geothermal power plant LCOE (left) and capex shares and risks for plant development stages (right)



Notes: O&M = operations and maintenance. Risk assessments account for the possibility of cost overruns and delays due to finding geothermal resources of insufficient quality, lengthy permitting and unforeseen technical challenges.

Sources: IEA analysis based on data from IRENA, BNEF and NREL.

Permitting, geothermal resource exploration and test-well drilling make up another 10-15% of investment costs. This predevelopment stage represents the highest project risk, as it can lead to delays and cost increases due to lengthy permitting, unsuccessful geothermal resource exploration or unforeseen technical challenges. Risk in this phase is influenced by the complexity and duration of permitting procedures, the availability of sound geological data and the number of test wells.

The remaining 5-10% of the total cost is related to engineering, management and contingencies. In addition, in remote areas where many high-quality geothermal resources are located, constructing new roads and transporting materials over long distances can have a significant impact on overall investment costs.

In most cases, only a limited number of investors are willing to take the risks involved with the resource exploration and well-drilling phases, resulting in a high cost of capital, which drastically impacts the competitiveness of geothermal power. For instance, doubling the weighted average cost of capital from 5% to 10% can increase the overall LCOE of a geothermal plant by about 40%.

The costs of heat generation from geothermal resources depend on a similar set of factors as those influencing power generation, resulting in a wide range of observed values. Investment costs for direct-use applications, such as geothermal heating in industry or district heating, are approximately 30–50% lower than those for power generation due to the absence of expensive electricity generation equipment. Consequently, the resulting heat costs can range from 4 to over 40 USD/GJ, with typical values falling between 5 and 30 USD/GJ.

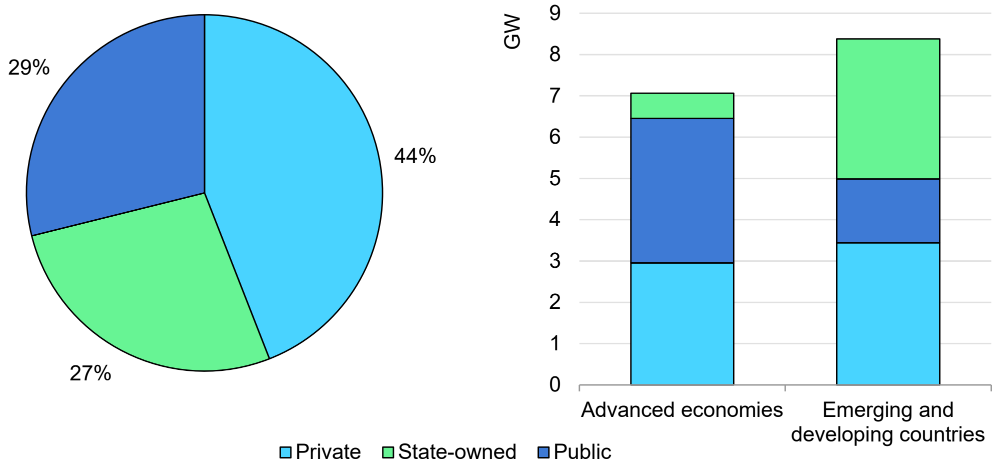
For instance, the average cost of geothermal heat supplied to district heating systems was estimated in 2014 at 22 USD per gigajoule (GJ) in the European Union and in 2017 at 10 USD/GJ in the United States. However, the competitiveness of geothermal heating is highly dependent on local circumstances, including the availability of alternative technologies, fuel costs, carbon pricing, and the required heat parameters (Chapter 4 provides a detailed discussion of the costs associated with various heating technologies)

Investment and ownership

Ownership

Publicly traded or private firms own or are planning to develop the majority of geothermal operations for power generation, accounting for over 70% of installed, under-construction and planned capacity. Of all firms, 7% of projects deployed or in development are fully or partially owned by oil and gas companies, and most of these are state-owned (e.g. Pertamina Geothermal Energy in Indonesia).

Shares of operational and planned ownership by type (left) and operational and planned geothermal capacity ownership by economy and ownership type (right), 2023



Note: Includes Australia, Austria, Chile, China, Chinese Taipei, Colombia, Costa Rica, El Salvador, Ethiopia, France, Germany, Guadeloupe, Guatemala, Honduras, Hungary, Iceland, Indonesia, Italy, Japan, Kenya, Mexico, New Zealand, Nicaragua, Papua New Guinea, the Philippines, Portugal, Russia, Thailand, Türkiye and the United States.

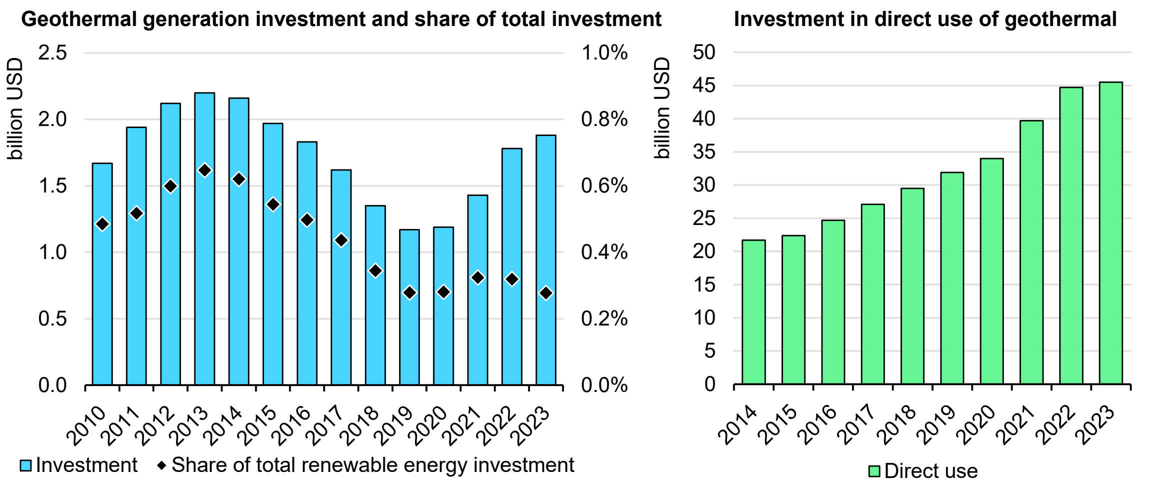
However, state-owned enterprises still play an important role in global geothermal project development, accounting for nearly 30% of the total. Emerging and developing economies host nearly 85% of all operational state-owned plants, with Indonesia registering the greatest amount of installed capacity, followed by Mexico, Kenya, Costa Rica and El Salvador.

Given the development timelines (up to eight years depending on the market) and amount of capital required for geothermal exploration, state-backed firms, which may benefit from development bank-backed loans or grants, are in a better position to secure affordable financing for projects. Plus, if the location of the resource means that grid expansion is required, state-owned organisations could also spur the development of enabling infrastructure to connect projects to the grid.

Investment

In 2023, geothermal power and heat investments exceeded USD 47 billion, accounting for over 5% of total spending on all renewable energy projects. Heating applications for residential and commercial buildings, including ground-source heat pumps, make up over 95% of global geothermal investments. China alone registered more than 70% of all geothermal investments.

Global investments in geothermal power plants and in direct use, 2010-2023



Source: Analysis based on IEA (2024), World Energy Investment 2024.

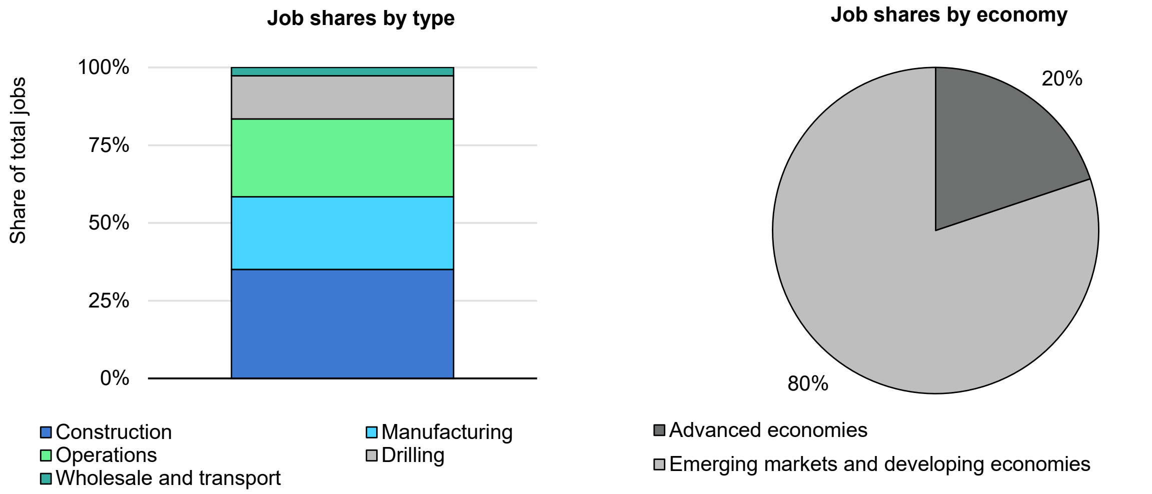
Investments in the use of geothermal energy for heating and/or cooling have been increasing steadily and have in fact doubled since the IEA first began tracking them in 2014, though China is almost exclusively responsible for this rise. Chinese policy under the 13th and 14th Five-Year Plans – including targets for the amount of area heated by geothermal energy – has driven recent uptake. Outside of China, geothermal investments have been climbing since 2022, after falling year over year from 2014 to 20210. Policy support in the United States (tax credits) and Europe (EU member country support for renewable heat) has encouraged this increase in investments.

After peaking in 2013, geothermal power plant investments declined through 2019 before increasing again. In 2023, geothermal power generation development represented less than 1% of total renewable power investments. Regionally, investments in geothermal generation are highly concentrated in emerging economies in Southeast Asia and Africa, which represented nearly three-quarters of investment in 2023.

Jobs

Today, around 140 000 jobs are associated with geothermal power development and operations worldwide[5]. Geothermal jobs are currently more concentrated in developing and emerging economies, which host a higher share of operational capacity than advanced economies. The manufacturing of equipment, including major parts such as steam turbines, steam-gathering systems, generators, cooling towers and abatement systems, accounts for almost 25% of all geothermal jobs.

Shares of geothermal-for-power jobs by segment and total jobs by economy type, 2023



Constructing conventional geothermal power plants is labour-intensive and involves multiple phases, including surface exploration, exploration drilling, production-well drilling, powerplant construction and testing. These tasks are responsible for nearly 50% of total jobs, one-quarter of which are dedicated to drilling geothermal wells, which employed an estimated 20 000 people in 2023.[6] Large developers such as Ormat employ their own drilling teams, while smaller firms outsource their drilling operations to drilling service companies. The

[5] The International Geothermal Association estimates that, when including heating and cooling, a total of 250 000 jobs are directly associated with geothermal activities. IEA values only include jobs associated with geothermal for power.
[6] This estimate assumes 25 employees per rig, with an additional 50 for drilling services; moreover, this estimate assumes 250 wells were drilled for geothermal resources in 2023.

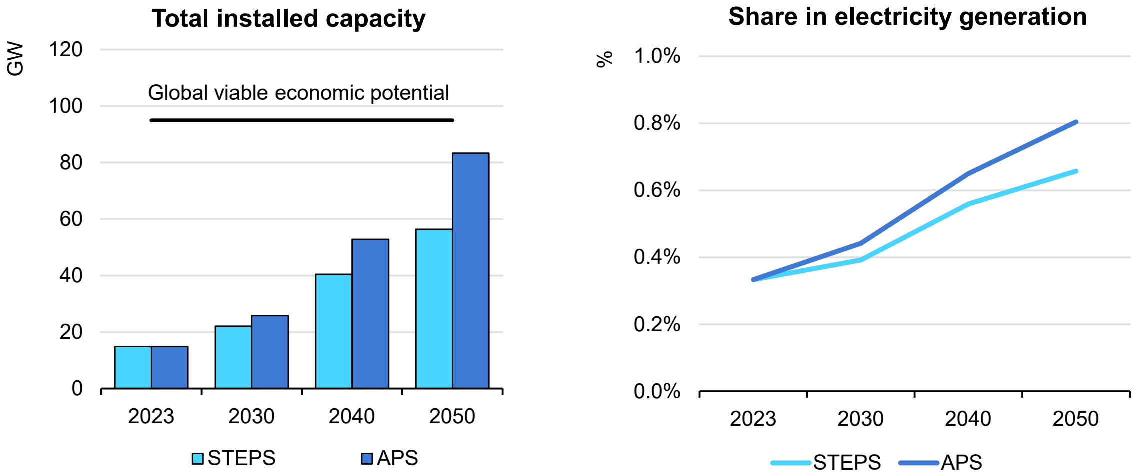
operations and maintenance of a geothermal plant is less labour-intensive than construction and drilling, but this domain creates more than 35 000 jobs.

Outlook

Power outlook

Global conventional geothermal capacity is expected to increase almost 50% to 22 GW in 2030 and to almost 60 GW in 2050 in the IEA Stated Policies Scenario (STEPS). This scenario assumes that projects under development and planned for the upcoming decade will be deployed under existing government policies. Beyond 2030, the untapped economic potential of hydrothermal resources, long-term government goals – and increasing geothermal competitiveness – drive further growth through 2050. In fact, the Announced Pledges Scenario demonstrates that global geothermal capacity in 2050 could be more than 30% higher, reaching over 80 GW with faster implementation of existing projects and the permitting of new drilling.

Projected global conventional geothermal power capacity and electricity generation shares by scenario, 2023-2050



Notes: STEPS = Stated Policies Scenario. APS = Announced Pledges Scenario.

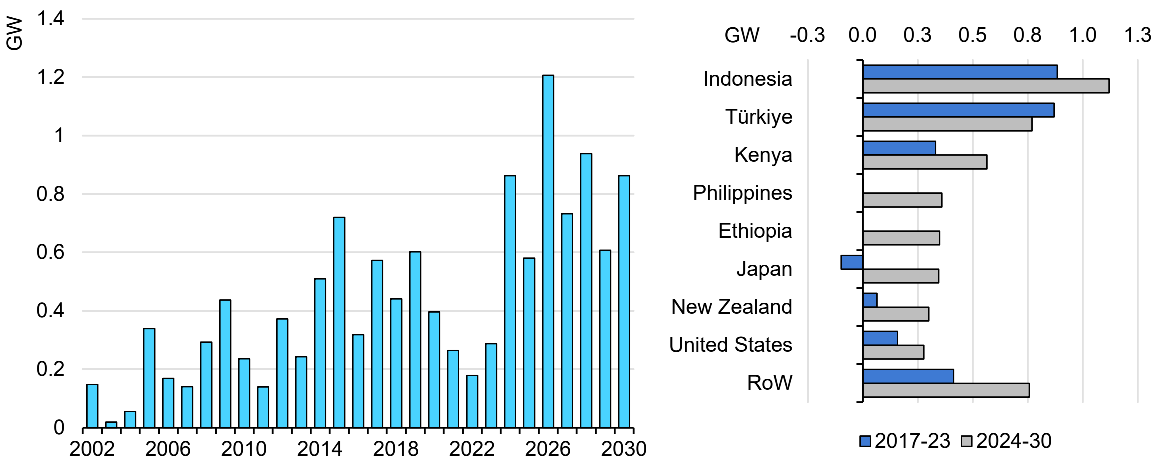
Source: IEA (2024), World Energy Outlook 2024.

As the need for dispatchable renewables increases, we expect geothermal growth to accelerate beyond 2030. Nevertheless, the outlook for conventional geothermal power capacity in both the Stated Policies and Announced Pledges Scenarios remains significantly below untapped economic potential in almost all countries. This reflects the prohibitive investment cost of developing geothermal projects compared with other renewables such as solar PV and onshore wind, and a lack of policy attention and awareness to address high predevelopment risks. As a result, while the share of geothermal in global electricity supply is expected to increase in all scenarios, it remains below 1% in 2050.

Global annual geothermal electricity capacity additions have been fluctuating over the past decade (from less than 200 MW up to 800 MW per year) due to the commissioning timelines of a handful of large projects. Growth in 2024-2030 is expected to increase compared with 2017-2023 deployment in most traditional geothermal markets. Indonesia leads expansion through 2030, thanks to large-scale projects being constructed under private-public partnerships, followed by Türkiye, where 15-year feed-in tariffs support growth.

In the Philippines, Ethiopia, Japan and New Zealand, only a few projects have been commissioned since 2017. However, policies support expansion in all four markets by 2030. In the United States, federal tax credits, state-level incentives and growing demand for dispatchable clean energy drive growth. In addition, in March 2024 the US House of Representatives passed a new bipartisan bill (the Geothermal Energy Opportunity Act) facilitating permitting for geothermal developments on public land.

Annual conventional geothermal capacity additions and growth, 2002-2030



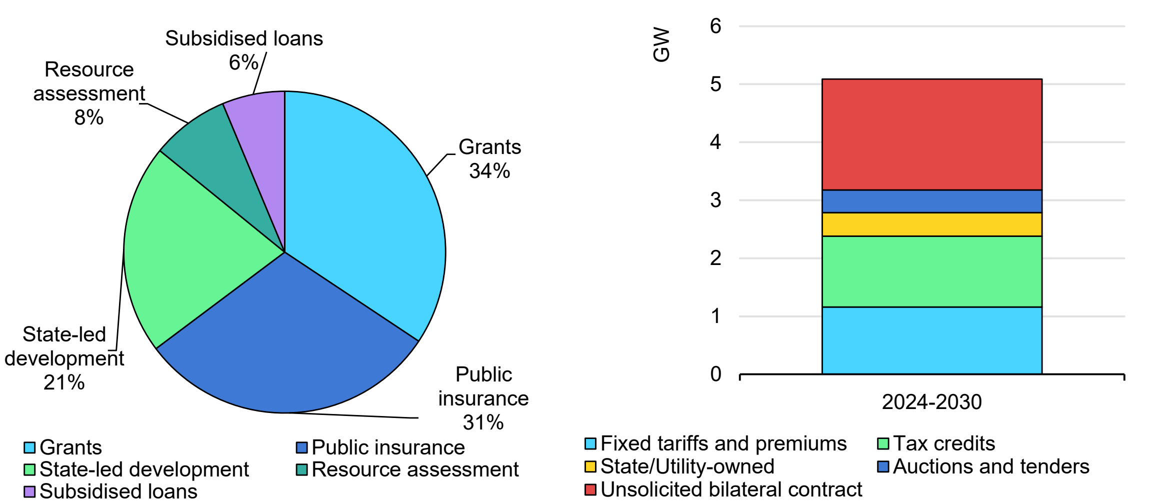
Note: RoW = rest of world.

Source: IEA (2024), Renewables 2024.

Policies addressing predevelopment risks and providing long-term remuneration mechanisms remain key for the deployment of foreseen projects. Grants, public insurance schemes and state-owned enterprises contributing to geothermal project predevelopment (including exploration and test drilling) provide most of the risk mitigation mechanisms.

Drilling activities in Ethiopia and Tanzania are supported with direct grants under the Geothermal Risk Mitigation Facility (GRMF) in Eastern Africa. Direct grants are also the main risk mitigation scheme in the United States. Public insurance schemes can take the form of Türkiye's risk-sharing mechanism or Japan's Organization for Metals and Energy Security (JOGMEC) guarantee. State-owned predevelopment prevails mainly in Kenya and Indonesia, where the Geothermal Development Company (GDC) (Kenya) and the State Electricity Company (PLN) (Indonesia) are conducting the majority of exploration drilling. State-led resource assessments and subsidised loans underpin the remaining capacity, contributing less than 10% each. Subsidised loans are used in Indonesia, which has set up a scheme with the World Bank.

Conventional geothermal capacity additions by risk mitigation scheme (left) and by remuneration (right), 2024-2030

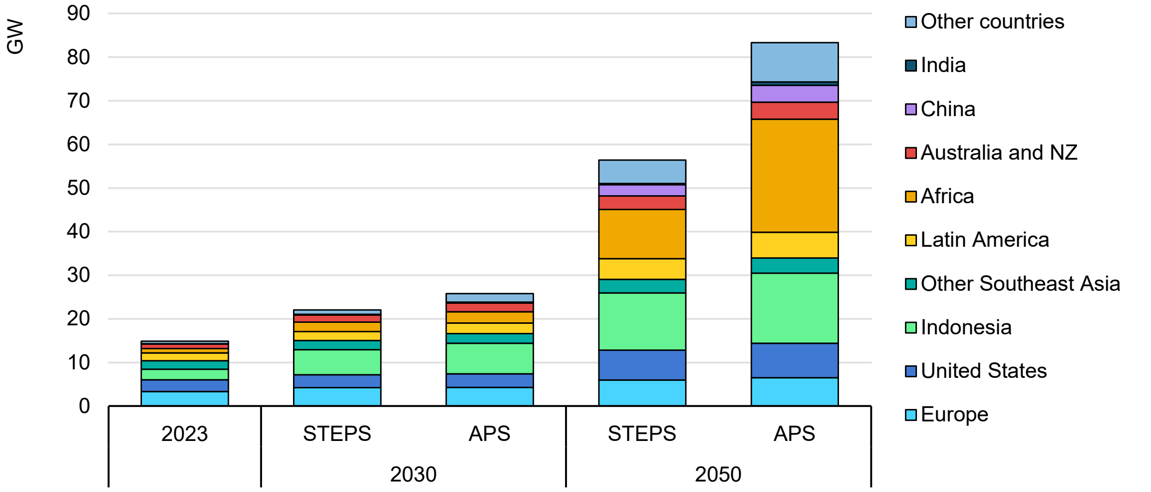


In terms of remuneration schemes, almost two-thirds of geothermal power capacity additions between 2024 and 2030 are expected to be policy-driven. The largest policy-driven additions are spurred by tax credits and fixed tariffs and premiums (around 1.2 GW each). Tax credits are applied mainly in the United States, while fixed tariffs are the main driver in countries such as Türkiye and Japan. State and utility-owned projects in Indonesia and Kenya and competitive auctions in Philippines add another 0.4 GW of capacity each. Market-driven geothermal deployment is concentrated mostly in Indonesia Kenya and Ethiopia, where unsolicited bilateral contracts propel around 1.6 GW of new projects by 2030.

Between 2030 and 2050 in the Stated Policies Scenario, Africa is responsible for the largest geothermal expansion as it develops its considerable untapped conventional geothermal resources relatively cost-effectively to meet quickly rising power demand. Although wind and solar PV power plants can provide electricity more affordably than geothermal facilities in many African countries, deploying them rapidly to accommodate growing power demand can pose integration challenges due to weak grid infrastructure.

In addition to having a key role in generating baseload electricity, geothermal plants can also boost flexibility as dispatchable low-emissions generators. In the Announced Pledges Scenario, an improved macroeconomic environment and widespread policy support that addresses development risks can unlock 25 GW of geothermal capacity in Africa by 2050, making it host to the largest installed capacity.

Geothermal power capacity by country/region and by scenario, 2023, 2030 and 2050



Notes: STEPS = Stated Policies Scenario. APS = Announced Pledges Scenario.

Heat outlook

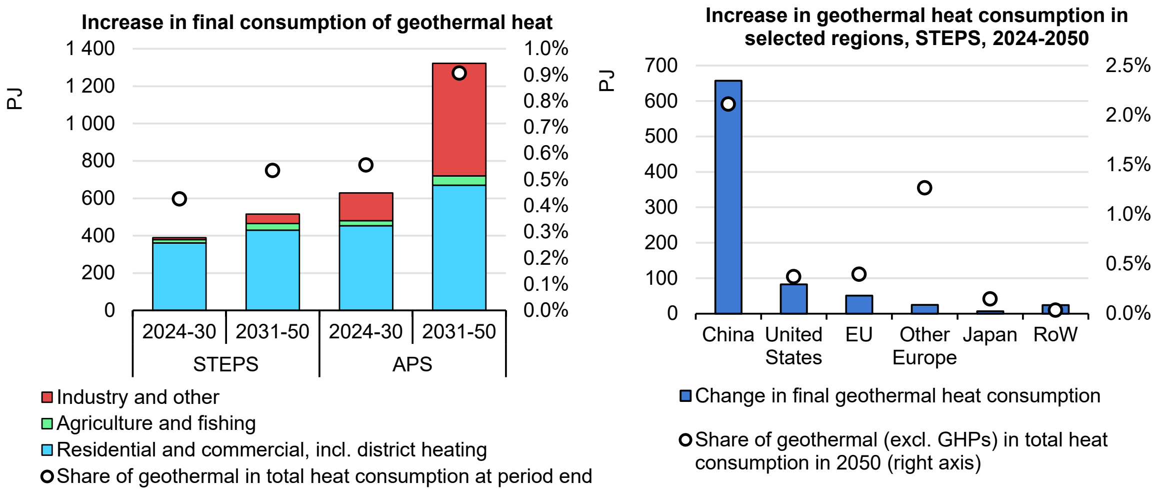
In the Stated Policies Scenario, the use of geothermal resources for heating doubles by 2030 and triples by 2050. Nevertheless, its share in overall heat consumption remains at roughly just 0.5% in 2050. Geothermal energy use in residential and commercial buildings (including for thermal baths in the tourism/wellness sector), mostly through district heating networks, accounts for almost 90% of the geothermal consumption increase to 2050. The direct use of geothermal heat for industrial processes also grows in sectors that require low and medium temperatures, including for various food and beverage, textile, paper and chemical applications.

China continues to be the largest geothermal energy producer in the Stated Policies Scenario, responsible for almost 70% of the increase in direct use by

2050. The country's efforts to decarbonise its district heating networks, combined with growing industrial heat demand, drive geothermal expansion. It is anticipated to remain the largest geothermal heat market over the outlook period. The second-largest growth market for geothermal heating is the United States, followed by Europe, where EU member states have ambitious plans to reduce CO_2 emissions from heating and cooling.

In the Announced Pledges Scenario, the generalisation of effective derisking policies, streamlined permitting procedures and faster implementation of policy goals could boost new geothermal heat developments 50% by 2030 compared with the Stated Policies Scenario. Deployment after 2030 could also accelerate, including in the industry sector, with a growing number of applications for low-temperature processes.

Increases in direct conventional geothermal use in the Stated Policies and Announced Pledges Scenarios, 2023-2050



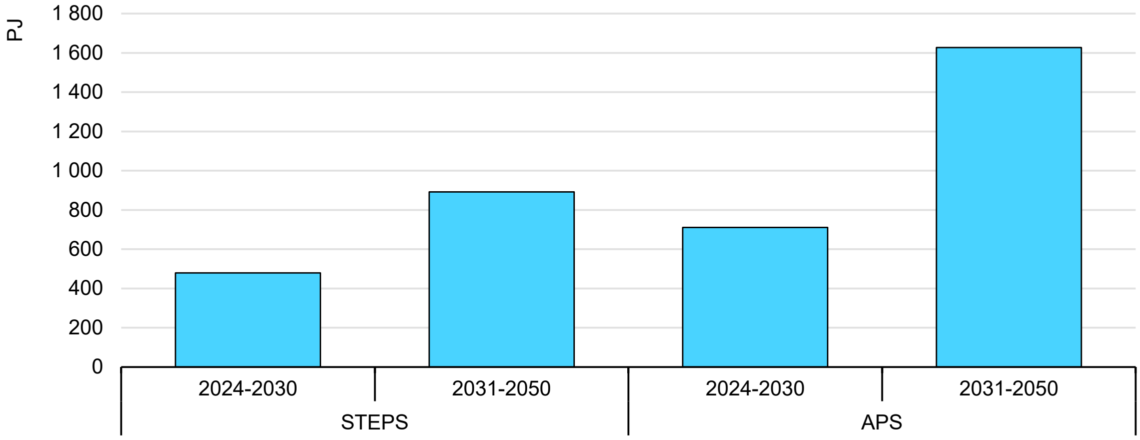
Notes: STEPS = Stated Policies Scenario. APS = Announced Pledges Scenario. RoW = rest of world. GHPs= geothermal heat pumps. Residential and commercial heat figures exclude geothermal heat pumps.

Source: IEA (2024), World Energy Outlook 2024.

Ground-source (geothermal) heat pumps for residential and commercial applications are also key contributors to overall geothermal energy consumption for heat. In the Stated Policies Scenario, the amount of heat they supply doubles to more than 1000 PJ in 2030 and to almost 2000 PJ in 2050, making them the primary user of geothermal energy for heating globally. Geothermal networks combining ground-source (geothermal) heat pumps with district heating and cooling systems are becoming an increasing driver for expansion.

What is more, in the Announced Pledges Scenario, expanding policy support and cost reductions achieved through technology standardisation and economies of scale push ground-source heat pump consumption to almost 3 000 PJ – 50% higher than in the Stated Policies Scenario. China, the United States and Europe together account for 80% of ground-source heat pump growth in the two IEA scenarios.

Increase in global heat delivered by geothermal heat pump in the Stated Policies and Announced Pledges Scenarios, 2023-2050



Notes: STEPS = Stated Policies Scenario. APS = Announced Pledges Scenario.

Source: IEA (2024), World Energy Outlook 2024.

Chapter 2: Geothermal innovation and technical potential for next generation technologies

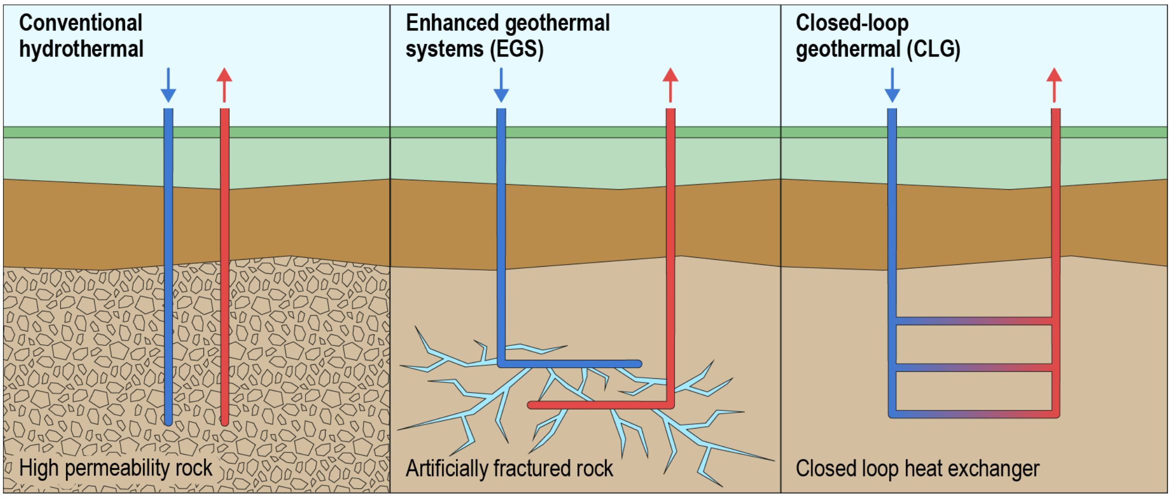
Recent technological innovation

Until recently, geothermal energy development was essentially circumscribed to the exploitation of either ground-source heat pumps that can harness shallow, low temperature geothermal heating and cooling resources anywhere, or higher temperature but location-specific naturally formed hydrothermal reservoirs. Clearly, in developing conventional geothermal systems for high-temperature industrial applications and to generate geothermal power, reservoir dependency is a strong limiting and risk-increasing factor.

Fortunately, efforts to overcome geological limitations have led to growing research activity and breakthrough innovations in recent decades. Building upon techniques and knowhow developed for – and by – the oil and gas sector (especially in the areas of hydraulic fracturing, well insulation and directional drilling), geothermal developers are experimenting with new approaches that enable the exploitation of geothermal energy independent of natural hydrothermal reservoirs.

These “reservoir-independent” approaches, currently being tested through pilot, demonstration and commercial projects, generally fall into two main categories: enhanced – or engineered – geothermal systems (EGSs) and closed-loop geothermal systems (CLGSs; also called advanced geothermal systems [AGSs]). These new-generation geothermal technologies have the potential to make geothermal power generation and direct-use heating accessible in parts of the world where conventional geothermal resources are not available, creating significant decarbonisation opportunities.

Conventional (hydrothermal), enhanced geothermal and closed-loop systems



Note: Closed-loop geothermal systems (CLGSs) are also referred to as advanced geothermal systems (AGSs).

Enhanced geothermal systems

Enhanced geothermal systems (EGSs) expand existing geothermal reservoir capacity or create new reservoirs by enhancing hot-rock permeability, typically by drilling deep wells and opening up natural fractures in the rock and/or creating new ones through:

- Hydraulic stimulation, the process of injecting fluids – generally water, sometimes with additives and proppants – at high pressure into underground rock formations to create and propagate new fractures in the rock reservoir (hydraulic fracturing) or to reactivate and open natural fractures (hydroshear stimulation). The latter induces shear movement along existing fracture planes, allowing fluid and heat to flow more efficiently. Hydraulic stimulation is one of the most-used methods.
- Thermal stimulation, the process of circulating a cold fluid into the hot-rock mass to induce thermal shocks.
- Chemical stimulation, the process of circulating a chemical compound (e.g. mineral acids or a chelating agent) to dissolve specific minerals and create voids – generally done in complement to hydraulic or thermal stimulation.

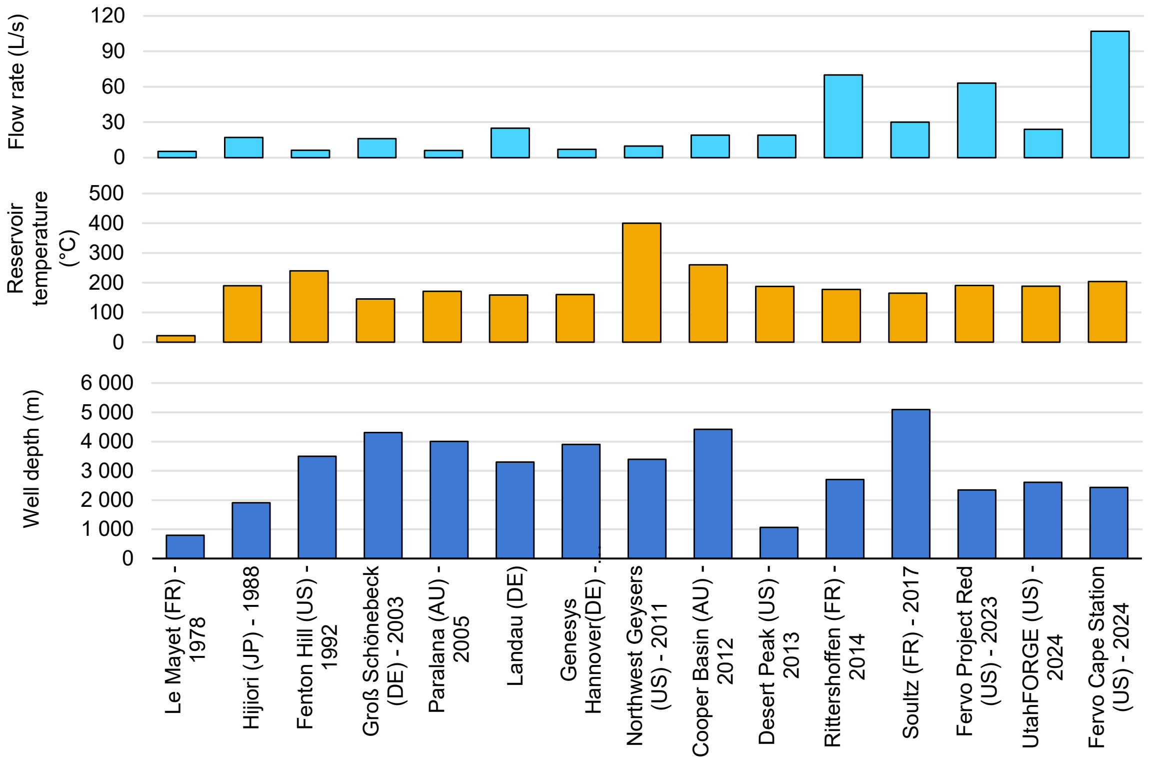
The resulting fractures allow fluids to circulate throughout the hot rock to absorb heat and transport it to the surface, where it can be used directly or to produce electricity.

EGS techniques expand the technical potential of geothermal energy considerably, for instance by making exploitation possible in regions with high subsurface temperatures but insufficient fluid volumes and natural rock permeability (such geological settings were sometimes referred to as “hot dry rock”

[HDR] in the past). With further innovation, EGSs could take advantage of deep, very-high-temperature (>375°C) impermeable crystalline basement formations, which could boost energy flows significantly.

EGS approaches have been explored since the 1970s, with the first pilot project drilled at Fenton Hill in the United States in 1974. Since then, over 30 experimental EGS projects have been operated with varying levels of success, including in Australia, Finland, France, Germany, Japan, the United Kingdom, Switzerland and South Korea. Notable recent EGS breakthroughs include the use of horizontal wells (versus deviated wells in earlier projects) and multistage stimulation techniques (demonstrated in 2023 at Fervo's Project Red in Nevada), which increase reservoir volumes and heat transfer area, and make flow rates higher and more consistent.

Vertical well depths, reservoir temperatures and maximum sustained flow rates of selected enhanced geothermal projects



Notes: Dates correspond to the year the flow rate was achieved. Flow-testing duration varied significantly across sites, from hours to years.

Sources: Breede, K., K. Dzebisashvili and G. Falcone (2013), A Systematic Review of Enhanced (or Engineered) Geothermal Systems; Baujard, C. et al. (2017), Hydrothermal Characterization of Wells GRT-1 and GRT-2 in Rittershoffen, France; Norbeck, J.H. and T. Latimer (2023), Commercial-Scale Demonstration of a First-of-a-Kind Enhanced Geothermal System; Fervo Energy (2023), Fervo Energy Announces Technology Breakthrough in Next-Generation Geothermal; Fervo Energy (2024), Fervo Energy's Record-Breaking Production Results Showcase Rapid Scale Up Of Enhanced Geothermal.

Notable ongoing EGS projects include:

- The Utah FORGE research project (highly deviated deep wells more than 2 400 m below the surface in crystalline basement rock), begun in 2015 and sponsored by the US Department of Energy.
- Fervo Energy's 400-megawatt (MW) Cape Station project (21 horizontal geothermal wells at a target depth of 2 400 m) also in the United States, expected to start commercial operation in 2026.
- The Haute-Sorne project of Geo-Energie Suisse and Geo-Energie Jura in Switzerland, using the same concepts and technologies as the Utah FORGE and Fervo projects. A 4 000 m-deep vertical well was drilled in 2024 and a stimulation test is planned for spring 2025. If successful, a second well will be drilled in 2026 and the reservoir will be stimulated in 2027. Commercial power generation is planned for 2029 (expected capacity of 5 MW_e). The project has been financed by several Swiss city utilities and subsidised by the Swiss federal state (CHF 90 million of which CHF 65 million from the government).

EGS technology remains technically challenging, with multiple projects having experienced difficulties in reducing water losses and parasitic loads from pumping fluid through the system, and in maintaining well integrity, distributed permeability of the reservoir, high flow rates, and production temperatures over time.[7] In addition, reservoir stimulation generally requires a significant amount of water and engenders several risks, most notably induced seismicity from formation fracturing, which has already led to social opposition from local communities and the banning of the technique in some jurisdictions.

However, recent flow rate achievements in ongoing projects indicate that new experimental EGS approaches, such as the use of horizontal wells and cased wells, new stimulation methods and adherence to appropriate protocols for seismicity could help resolve some of these challenges.

Closed-loop geothermal systems

Closed-loop geothermal systems (CLGSs) – sometimes also referred to as advanced geothermal systems (AGSs) – require the drilling and sealing of deep, large, artificial closed-loop circuits. These systems act as underground heat exchangers in which a fluid is circulated and heated by surrounding hot rocks (without chemically interacting with them) through conductive heat transfer.

[7] Thermal short-circuits can happen in EGSs when reservoir porosity becomes uneven and the working fluid starts flowing through a preferred crack. This process is generally self-reinforcing and causes accelerated cooling of the rock around the predominant pathway, reduced heat exchange, and a premature drop in production temperature. Expensive flow-control measures are required to mitigate this risk, or interventions such as refracturing are necessary to extend project lifetimes.

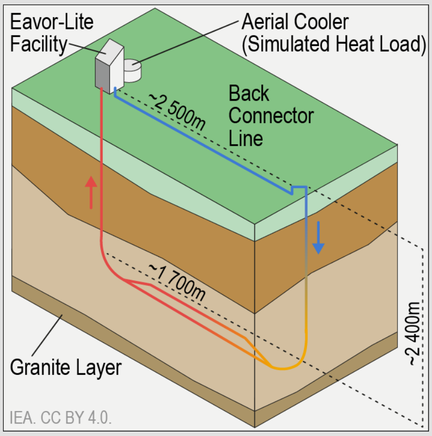
Different designs have been researched, including deep vertical doublets with laterals, and single vertical boreholes with concentric isolated pipes.

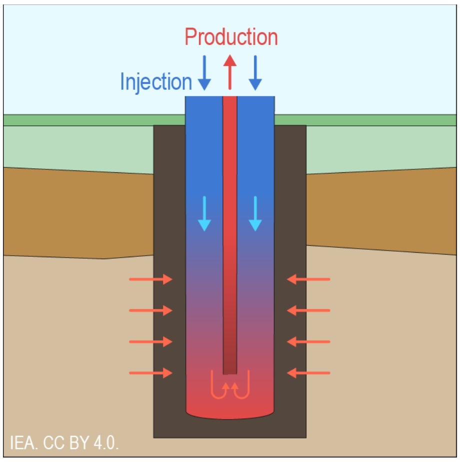
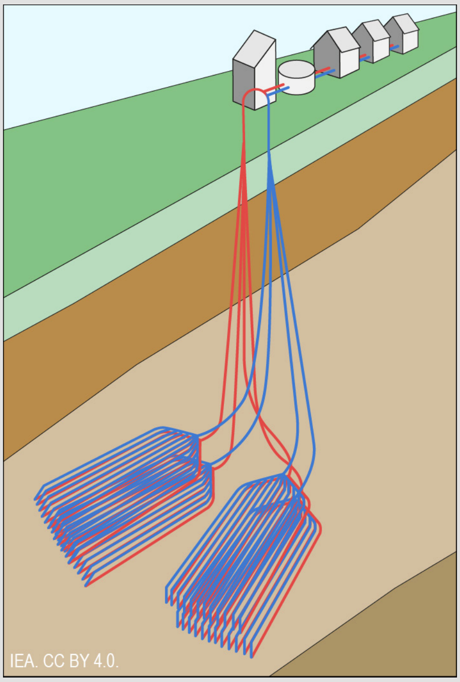
One advantage of CLGSs is that they have very few site-specific requirements, enabling their application virtually everywhere and limiting development risks related to resource availability. They also have relatively high output predictability, low water consumption and, in contrast with EGSs, do not require reservoir stimulation, which is expected to limit the risk of induced seismicity.

Technical challenges stem essentially from the considerable drilling distance required to create a sufficient heat transfer area within the surrounding rock. In fact, the drilling length is multiple times (i.e. an order of magnitude) longer than for traditional geothermal or EGS wells, which translates into higher costs and more complex downhole completions. Limiting production temperature declines over time is another difficulty that improved project designs and operating patterns will have to overcome. While EGS projects involve risk and uncertainty linked with specific site characteristics, CLGS challenges are more engineering related.

Concrete examples of closed-loop projects are more novel than EGSs. Although only a handful of CLGS concepts have materialised into full-scale projects to date, they have proven their technical feasibility. Nonetheless, there is still only a small amount of field data available to judge their long-term performance and scalability potential. CLGS examples include the 2019 Eavor-Lite™ demonstration project in Alberta, Canada, as well as GreenFire Energy's GreenLoop demonstration project at the Coso field in California, although the latter is a slightly different concept initially designed to retrofit existing hydrothermal wells. Notable ongoing developments include Eavor's commercial heat and power plant project in Geretsried, Germany.

Examples of closed-loop geothermal projects

Project (company)	Description	
Eavor-lite (Eavor)	**Location**: Alberta, Canada **Completion date:** 2019 • **Design**: U-tube-shaped closed loop with two 1 700 m-long laterals at a depth of 2 400 m, sealed with chemical completion technique, circulating a water-based working fluid driven by thermosiphon effect. • Outlet temperature: 50°C • **Flow rate**: 5.6 L/s	 Source: Eavor Technologies, 2024

Project (company)	Description	
Coso Greenloop (Greenfire)	**Location**: Walnut Creek, California, United States **Completion date**: 2019 • **Design**: Single well, 330 m-deep downbore co-axial heat exchanger through which water and supercritical CO_2 are circulated and returned to the surface through a vacuum-insulated tube. Designed as a well retrofit solution. • **Outlet fluid**: 180°C, 11 bar • **Flow rate** (water): 26 kg/s • **Output**: 1.2 MW_e	
Eavor-Europe (Eavor)	• **Location**: Geretsried, Bavaria, Germany • **Completion date**: Scheduled for 2027 for the overall project – drilling started in 2023 and power generation from the first heat exchanger is expected to start in the first half of 2025, while drilling for other exchangers continues. • **Design**: Four subsurface heat exchangers (called “Eavor-Loops”), each formed by twenty-four 3 500 m-long lateral wells drilled from the base of two 4 500 m-deep vertical wells and connected in pairs (totalling about 320 km of drilling length for the whole project), using water as working fluid, circulated by thermosiphon. **Expected output**: 64 MW_{th} / 8.2 MW_e	 Source: Eavor Technologies, 2024

EGS and CLG approaches are not intended to replace conventional geothermal techniques, which are expected to remain more cost-effective in suitable locations. These techniques are complementary, and their relevance depends on site characteristics and planned applications.

Technical potential

By avoiding the natural-reservoir dependency of conventional geothermal projects, EGS and AGS approaches enable the technical exploitation of geothermal heat in almost any location. Because subsurface temperatures generally increase with vertical depth,[8] the temperature conditions required for heat and power generation can be found by simply drilling deep enough, making a considerable amount of geothermal energy technically accessible.

In collaboration with the IEA, and building upon the Geothermal Exploration Opportunities Map (GeoMap™) project, Project InnerSpace™ has assessed the total technical geothermal potential of hydrothermal systems and EGSs specifically for this report using geographical information system (GIS) modelling and multiple regional and global data resources.

Project InnerSpace methodology for assessing combined conventional and EGS potential

The assessment method is based on a "heat-in-place" or "volumetric" approach (originally proposed by Muffler and Cataldi in 1978), which estimates the quantity of thermal energy stored in a subsurface volume up to a given depth and at a temperature greater than the minimum needed for the different applications (e.g. district heating, industrial processes, power generation).

This approach requires first that global heat density maps be established by estimating subsurface temperatures and porosity across the globe. Temperature profiles were built from surface temperature and geothermal temperature gradient datasets – the latter derived from multiple public domain sources. Porosity profiles were derived from sediment thickness maps, based on compaction curves.

The volume of the subsurface between 500 m and 8 000 m of depth was split into elementary volumes of approximately 1 km x 1 km at 500 m of thickness. The usable heat stored in each of these elementary reservoirs is represented by:

$$Q = V \cdot (\rho_R \cdot C_R \cdot (1-\varphi) + \rho_w \cdot C_w \cdot \varphi) \cdot Max\big(\, 0\,; (T - T_{cutoff})\big)$$

V is the volume of the reservoir considered (m^3)

ρ_R and ρ_w are respectively the densities of the rock matrix and the pore fluid (assumed to be water here) (kg/m^3)

[8] Temperature gradients vary by location. The global average is 25°C per km of vertical depth on the upper part of the continental crust, but some locations near tectonic borders and volcanic areas exceed 50°C per km.

C_R and C_w are respectively the specific heat capacities of the rock and the pore fluid under the reservoir conditions (kJ/kg·°C)

φ is the porosity of the reservoir (volume fraction of the fluid)

T is the reservoir temperature. Reservoir volumes with temperatures above 250°C for EGSs and above 350°C for hydrothermal applications were excluded due to field data limitations and additional challenges associated with higher temperatures.

T_{cutoff} is defined in relation to the application considered, to reflect minimum temperature requirements. For instance, this assessment chose relatively conservative assumptions of a cutoff temperature of 40°C for agriculture processes, 90°C for district heating, 60°C for low-temperature industrial processes and 200°C for medium-temperature processes – meaning it excludes subsurface volumes with temperatures below these values. For power generation, only subsurface volumes with temperatures above 150°C were considered, and T_{cutoff} was set to $T - 10°C$ to reflect constraints of acceptable reservoir temperature decline, related to the fact that power plants are designed to operate within a narrow range of fluid temperature conditions.[9]

Technical power generation potential is then derived from the calculation of total usable heat by applying a recovery factor of 20% (based on NREL, 2011, 2016 and 2023) and, for electricity, a heat-to-power conversion efficiency dependent on exergy (following Beckers and McCabe, 2019). This generation potential is then translated into power capacity, assuming 20 years of operation at a capacity factor of 80% for electricity and 25 years of operation at a capacity factor of 90% for heat.

Finally, the levelised cost of electricity and heat (LCOE/LCOH) associated with this technical potential is calculated considering the technology used (EGSs or hydrothermal), based on assumptions for the number of wells and flow rate; drilling and stimulation costs; power plant equipment costs; operating expenses; derisking and construction time; and the discount rate. Additional costs such as for transmission line requirements and grid connection are not included.

Assumptions used to assess geothermal potential

Parameter	Value
Number of wells	10
Horizontal length	3 000 m
Injector/producer ratio	1:1
Total flow rate	80 kg/s

[9] The assumed threshold of 10°C average temperature decline in the reservoir is based on NREL (2011, 2016 and 2023).

Parameter	Value
Temperature decline (°C/year)	10-year plateau followed by a 60°C temperature drop over the next 10 years
Productivity	5 kg/s/bar
Drilling cost	USD 2 000/m
Stimulation cost	USD 2 800/m
Power generation CAPEX	USD 2 250/kW
OPEX (as % of CAPEX)	2%
Production lifetime	20 years for power / 25 years for heat
Capacity factor	80% for electricity / 90% for heat
Derisking and construction time	6 years

Most of the geological data supporting this analysis are freely accessible through the GeoMAP™ platform, developed by Project InnerSpace™ in partnership with Google. The GeoMap™ platform provides surface and subsurface modules that include 200+ layers of data as well as a techno-economic sensitivity tool, allowing users to explore development potential in specific geographies.

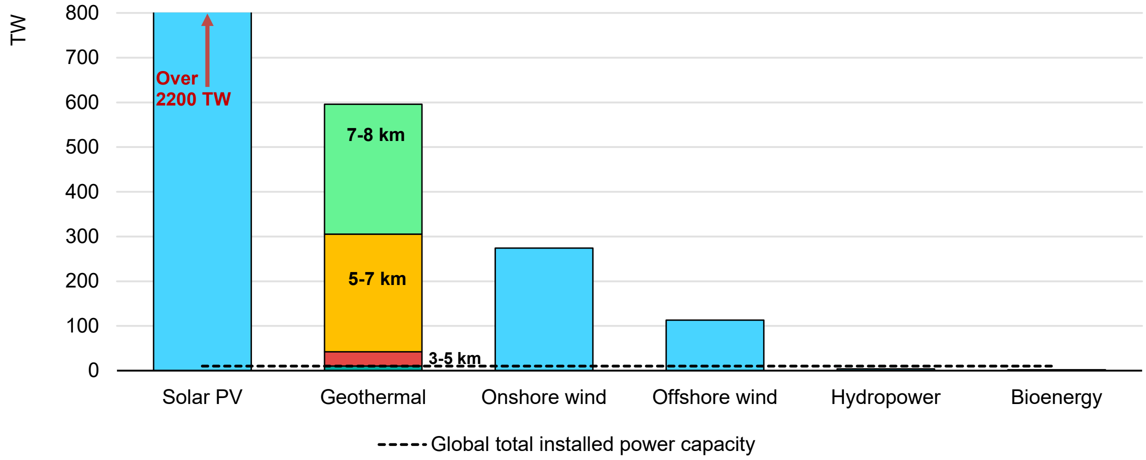
Many contributors have worked with Project InnerSpace™ on the GeoMAP project: Sven Fuchs and Florian Neumann (GFZ, Potsdam) for IHFC heatflow data; Veit Matt and Helen Doran for the BHT temperature database; Paul Markwick (Knowing Earth), Douglas Paton, Estelle Mortimer (Tectonknow) and Michal Nemčok (RM Geology) for tectonics; Nicky White, Megan Holdt and Philippa Slay (University of Cambridge) for sediment thickness; Sergei Lebedev, Yihe Xu, Raffaele Bonadio (University of Cambridge) and Javier Fullea (Universidad Complutense de Madrid) for lithosphere definitions and thermal modelling.

Electricity potential

Globally, the amount of electricity that could be technically generated by EGSs for less than USD 300 per megawatt-hour (MWh) using thermal resources within 8 km of depth is about 300 000 exajoule (EJ). This is equivalent to almost 600 terawatt (TW) of geothermal capacity operating for 20 years – exceeding the technical potential of conventional geothermal by almost 2 000 times.

Compared with other renewable power generation sources and technologies, geothermal has the second-largest technical potential for electricity-generating capacity after solar PV, and almost three times that of onshore wind and more than five times that of offshore wind. Given the average capacity factors of each renewable technology, geothermal's 4 000 petawatt-hour (PWh) (15 000 EJ) of technical potential for annual generation is about 150 times current global annual electricity demand. Furthermore, this estimate relates to electricity generation only, while in practice additional waste heat could also be used for district heating or industrial processes.

Technical potential of selected renewable energy technologies for electricity generation

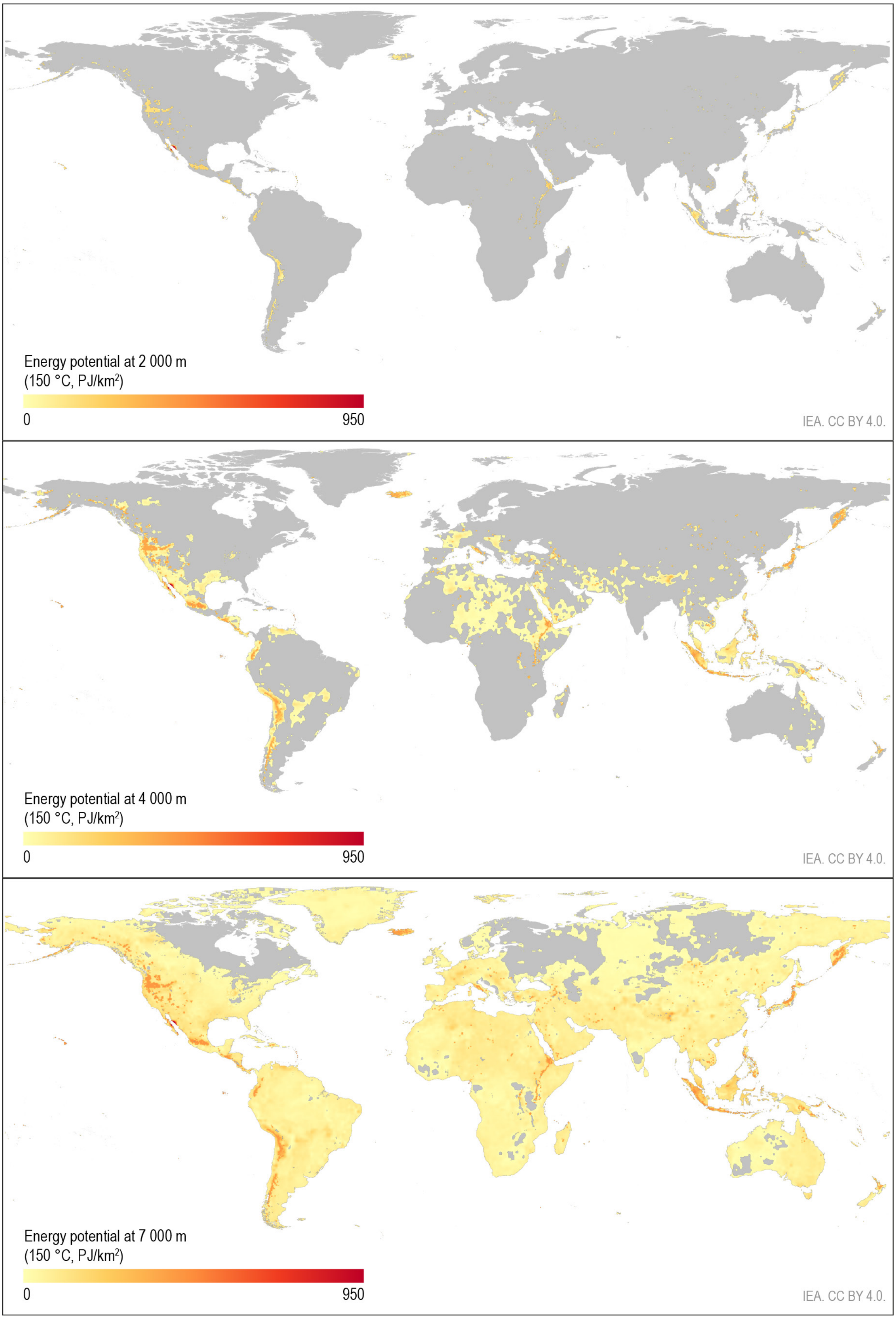


Sources: Geothermal: Project InnerSpace™ calculations for EGSs based on GeoMap™ data with a threshold of USD 300/MWh, in collaboration with IEA. Offshore wind: IEA (2019), Offshore Wind Outlook 2019. Hydropower: IEA TCP 2010. Bioenergy: IEA calculation based on the assumption that all sustainable bioenergy potential of 100 EJ is used for power generation. Onshore wind: based on DTU-2027 study. Solar PV: technical potential from various studies in de La Beaumelle N.A. et al. (2023), The Global Technical, Economic, and Feasible Potential of Renewable Electricity.

Geothermal energy potential increases as you tap into deeper and hotter resources. The technical potential for geothermal electricity at depths of less than 5 000 m is an estimated 42 TW of power capacity over 20 years of generation (21 000 EJ), while potential at 5 000-8 000 m exceeds 550 TW (280 000 EJ).

At a depth of 2 000 m, only a limited number of countries with favourable geothermal conditions can effectively harness high-temperature heat for electricity generation. Conditions for geothermal electricity generation generally become more widely plentiful at greater depths: for instance, almost every region has technically suitable resources beyond 7 000 m.

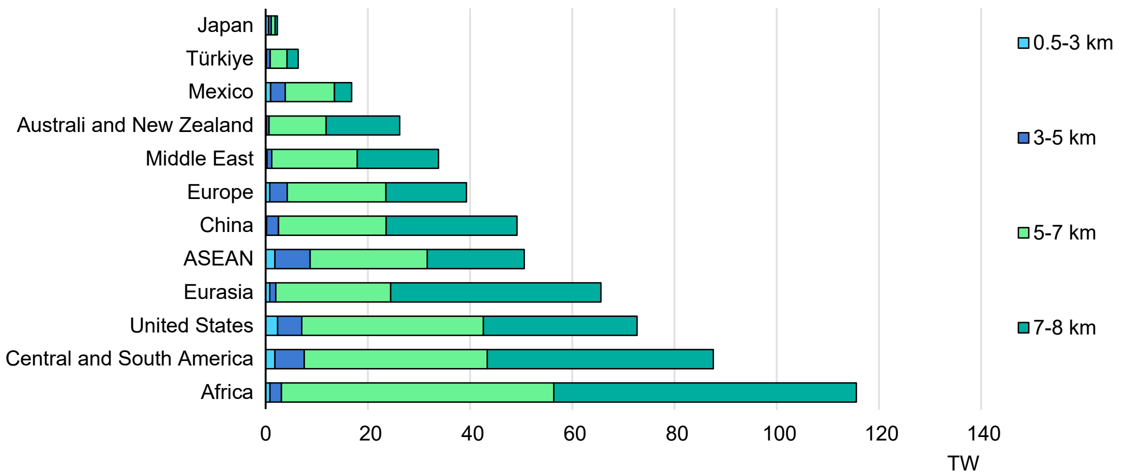
Global geothermal potential for electricity generation using EGS technologies



Source: Project InnerSpace™ calculations for EGSs based on GeoMap™ data.

Almost one-fifth (115 TW) of EGS power potential is in Africa, which also has the largest untapped conventional geothermal potential. In fact, even tapping less than 1% of this potential would meet Africa's electricity needs in 2050 in all IEA scenarios. As a country, the United States is assessed to have the world's largest technical enhanced geothermal capacity potential, with about one-eighth of the global total (over 70 TW). Even at a depth of 5 km, US technical potential is over 7 TW, seven times more than the country's total installed power capacity today. China has the second-largest potential, accounting for almost 8% (50 TW) of the global total. The Chinese government has identified the provinces of Hainan, Guangdong and Fujian as potential enhanced geothermal sites owing to their favourable geological conditions.

Technical potential for EGS electricity capacity by depth in selected countries/regions



Note: ASEAN = Association of Southeast Asian Nations.

Source: Project InnerSpace™ calculations for EGSs based on GeoMap™ data with a threshold of USD 300/MWh.

ASEAN countries together represent about 15% (125 TW) of the global technical potential for EGS power generation, with Indonesia and the Philippines in the lead.

Meanwhile, Europe, where several countries have been conducting EGS research and demonstrations since the 1970s, accounts for less than 5% (40 TW) of global potential – but this already represents 35 times Europe's current total installed electricity capacity. In India, potential for conventional geothermal is highly limited; however, at a depth of 5 km the country's potential grows considerably to around 14 TW. Within Gujarat State, the eastern coast of Andhra Pradesh and the central Son Narmada Fault Zone are among the key areas for geothermal power generation development.

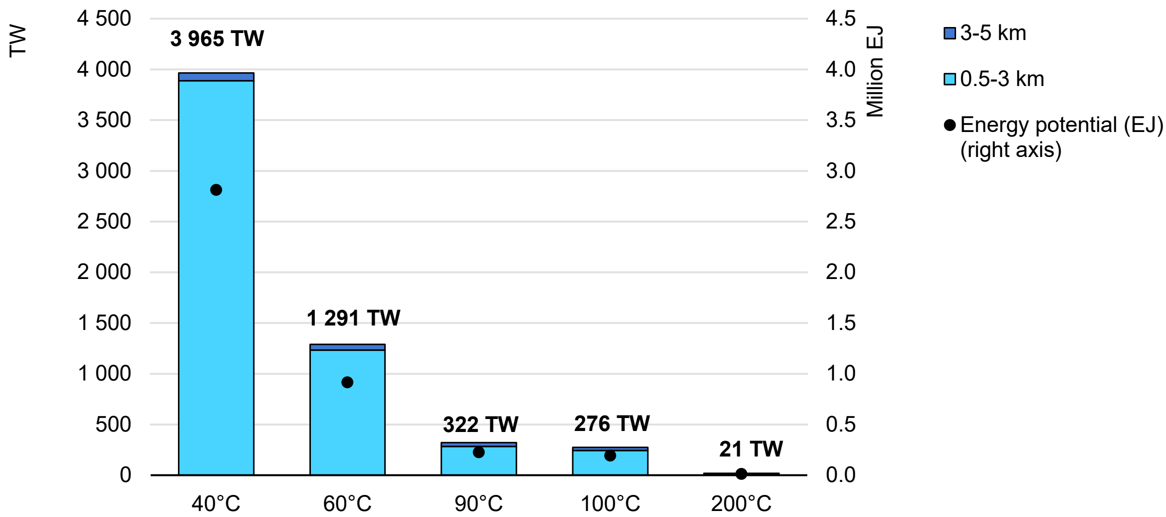
Heat potential

The amount of heat that can be extracted globally from sedimentary aquifers 0.5-5 km deep, at temperatures greater than 90°C using advanced techniques and at a levelised cost of less than USD 50/MWh, is estimated at more than 250 000 EJ – equivalent to an average heat flow of 320 TW sustained for 25 years.

The 90°C temperature threshold reflects the requirements of most current fossil fuel-fired district heating networks, which could be decarbonised by switching to geothermal heat using existing network infrastructure. However, for new high-efficiency district heating networks that operate at lower temperatures (<70°C), as well as for those that use geothermal heat pumps, the heat potential of hot sedimentary aquifers is even higher. Considering a minimum temperature threshold of 60°C, the estimated technical geothermal heat potential is four times larger (1 million EJ) than at 90°C.

Conversely, while geothermal heat at more than 200°C is less widely available, the corresponding technical potential is still about 15 000 EJ – representing almost 500 years of global below sub-200°C industrial heat demand at current levels.

Global technical potential for geothermal heat at different cutoff temperatures

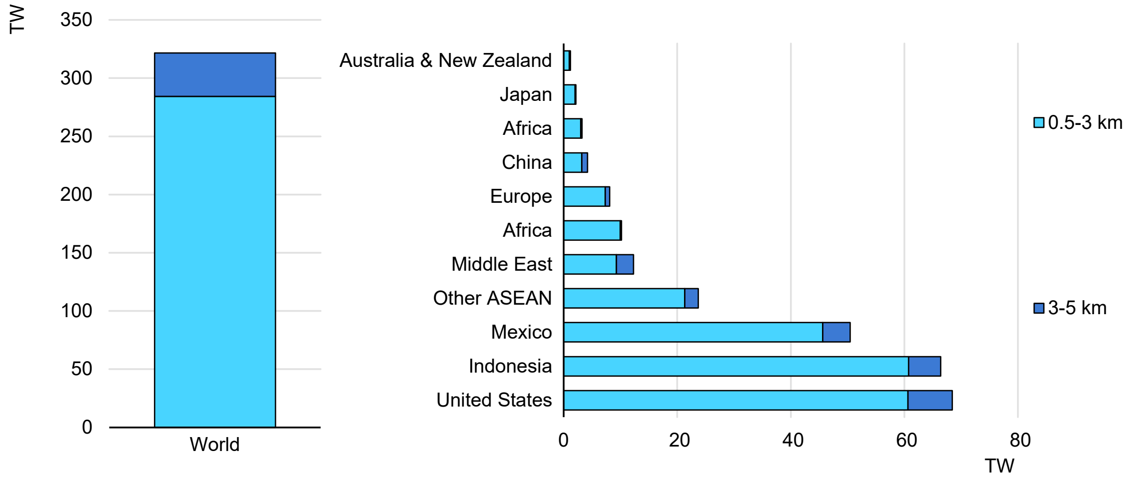


Notes: Heat potential covers resources within hot sedimentary aquifers only. The conversion from energy to heat flow capacity assumes that energy is used over 25 years of operation with a capacity factor of 0.9.

Source: Project InnerSpace™ calculations for conventional geothermal techniques based on GeoMap™ data with a threshold of USD 50/MWh.

Almost 90% of district heating potential from hot sedimentary aquifers lies at depths of less than 3 km, as only a few regions have deeper sediment layers. Beyond this depth, enhanced and closed-loop geothermal systems can technically be used independent of the presence of sedimentary aquifers to extract heat and supply it to district heating systems. However, as investment costs for these projects are still very high, combined heat and power generation could be a more attractive business model.

Technical potential for geothermal heat at 90°C by depth, selected countries/regions

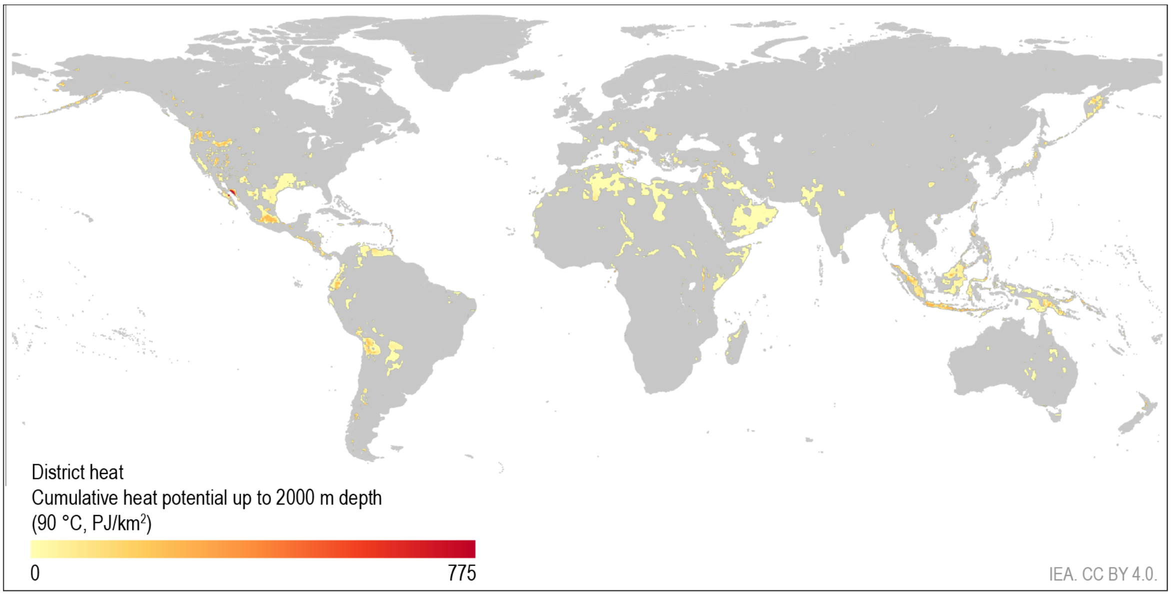


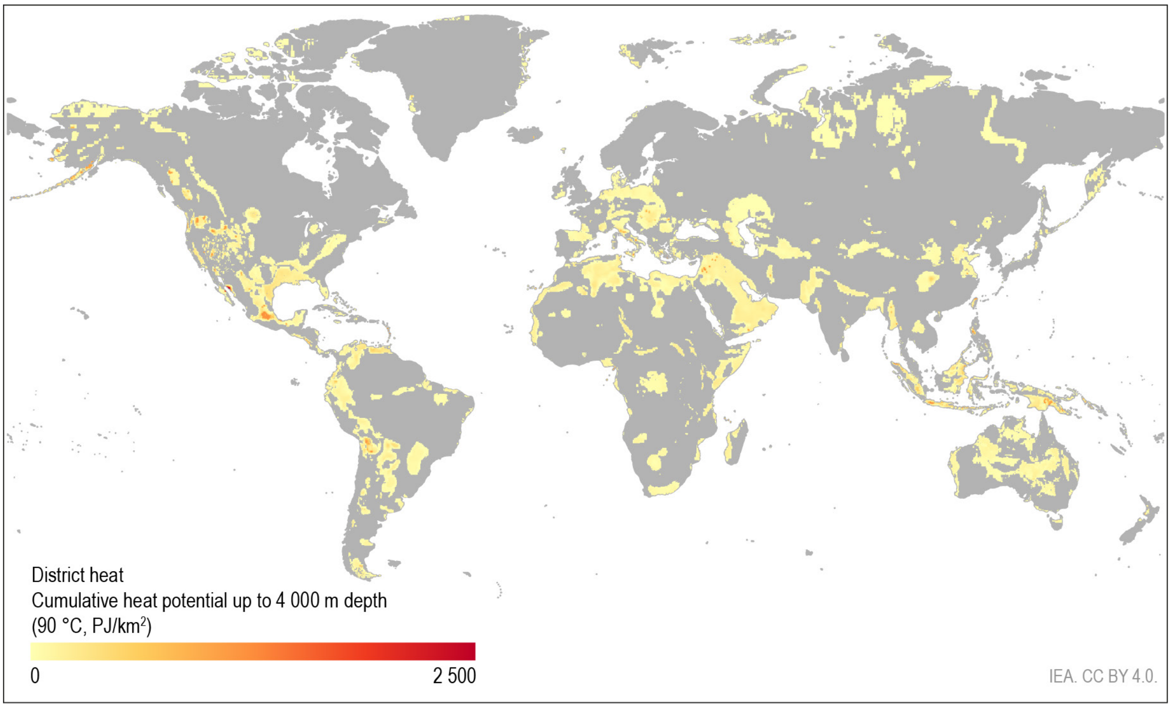
Notes: ASEAN = Association of Southeast Asian Nations. Potential covers hydrothermal resources within sediment layers only.

Source: Project InnerSpace™ calculations for conventional geothermal techniques based on GeoMap™ data with a threshold of USD 50/MWh.

Among the key regions and countries, the United States has the largest estimated geothermal heat potential at 90°C (68 TW), followed by Indonesia and Mexico. Africa also has significant potential of almost 10 TW. While district heating and cooling network infrastructure is limited in these regions, geothermal heat could meet a significant fraction of low-temperature heat demand in the industry sector, for processes commonly used in the food and beverage, textile, and paper industries (e.g. pre-heating, drying, sterilising, bleaching, dying, desalination and cooking). In Europe, hot sedimentary aquifers could provide about 8 TW of heat at 90°C – 30 times the energy district heating systems currently supply to more than 70 million people in the region.

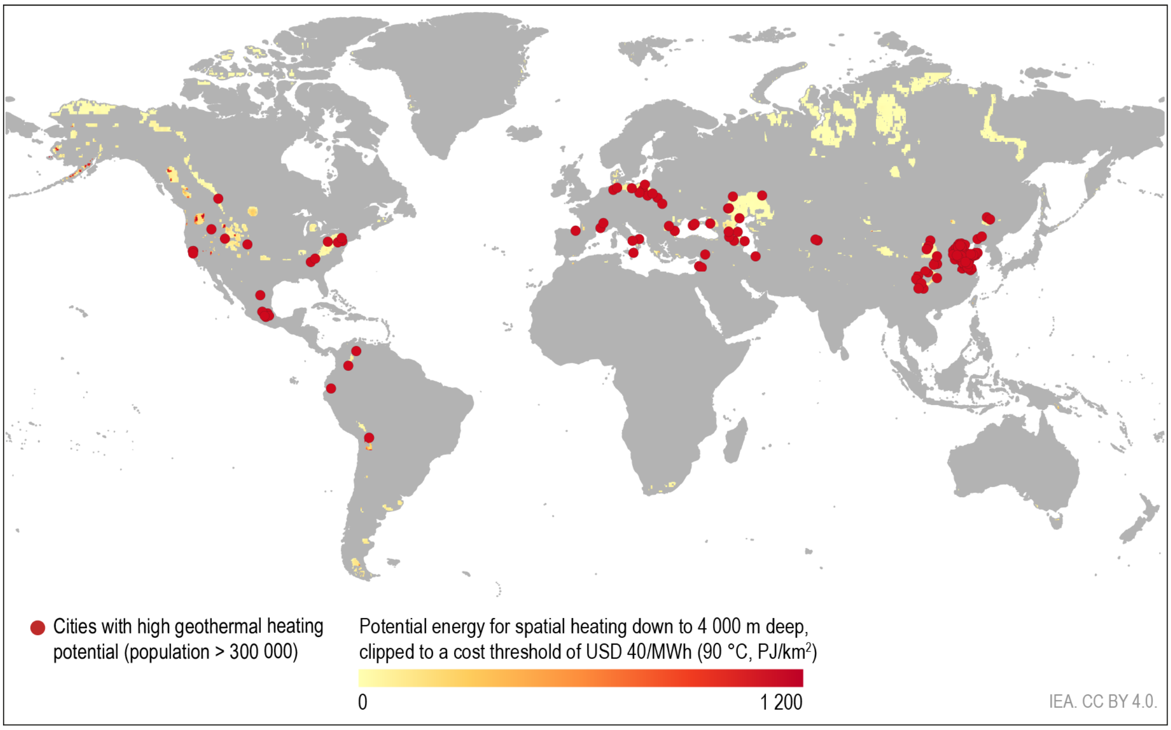
Global heat-in-place geothermal potential of hot sedimentary aquifers for district heating

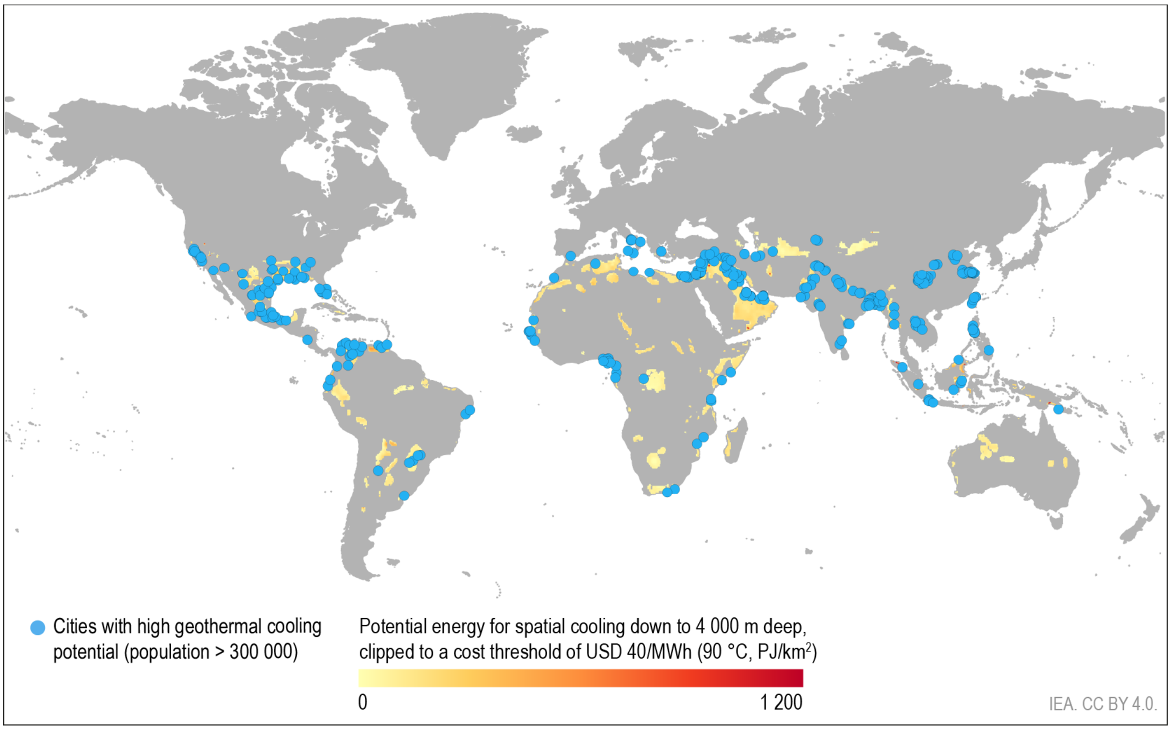




Source: Project InnerSpace™ calculations based on GeoMap™ data.

Overlap between urban centres and geothermal potential for district heating (top) and for cooling (bottom)





Note: Cities indicated on the map are urban areas with populations exceeding 300 000, with significant geothermal district heating or cooling potential.

Source: Project InnerSpace™ calculations for hot sedimentary aquifer systems based on GeoMap™ data with a cost threshold of USD 40/MWh.

Comparing and overlapping geothermal heat potential with population density data reveals particularly strong opportunities for district heating in multiple large cities across China, Mexico, the United States, Germany, Italy, Poland and Russian Federation (hereafter "Russia"). Geothermal energy also offers high district cooling potential in a number of large cities across the Philippines, Indonesia, Mexico and China.[10]

Key technical challenges

Induced seismicity

Any action that alters the state of subsurface stress has the potential to induce seismicity, depending on the geological context. This risk concerns conventional as well as closed-loop systems to some extent due to the long-term cooling of the reservoir or rocks associated with their operation.[11] In the case of EGSs, reservoir stimulation is an additional risk factor for induced seismicity, as it can result in earthquakes that could damage local infrastructure and facilities. Any occurrence in populated areas is likely to trigger social opposition and delay or halt project development.

Induced seismicity has already caused some projects to be suspended, for instance in Basel, Switzerland, where hydraulic fracturing triggered multiple seismic events of up to magnitude 3.4, leading to project cancellation in 2009. In Pohang, South Korea, an earthquake of magnitude 5.4 in 2017 also led to the suspension of a geothermal project, although the earthquake's origin and causality are still under debate.

In 2012, the US Department of Energy published a protocol detailing general guidelines to address induced seismicity associated with EGS projects. Several research projects have also advanced understanding of induced-seismicity factors to mitigate associated risks – for instance highlighting that, in low-porosity rock formations, injecting fluid into existing low-permeability fault networks can cause more seismicity than creating new fracture networks in previously unfractured rock.

[10] Large cities with particularly strong district heating potential include: Mexico City, Pachuca de Soto, Toluca de Lerdo, Tlaxcala, Querétaro and Cuernavaca in Mexico; Boise City, Antioch, Ogden-Layton and San Jose in the United States; Beijing, Xingtai, Shijiazhuang and Tangshan in China; Hamburg in Germany; Warsaw in Poland ; Catania in Italy; Damascus in the Syrian Arab Republic; and Vladikavkaz in Russia. Large cities with particularly good geothermal resources for geothermal district cooling include: Bandung, Bogor and Tasikmalaya in Indonesia; Angeles City, San Fernando, Manila, San Jose del Monte, Antipolo, Imus, San Pedro, Cabuyao, Dasmanrinas, Binan and Bacoor in the Philippines; Nanjing and Taoyuan in China; Querétaro and Celaya in Mexico; Damascus in the Syrian Arab Republic; and Dakar in Senegal.
These examples are derived from a weighted overlap analysis based on population density, energy demand for heating and cooling, and geothermal potential. Project InnerSpace carried out this analysis in collaboration with the IEA.

[11] Local communities usually accept the small earthquakes potentially associated with conventional geothermal projects in tectonically active areas because the relatively high number of natural earthquakes in these regions has bred familiarity with seismic occurrences. However, public acceptance of induced seismicity could differ in areas far from tectonic activity.

While seismicity risks remain inherent to reservoir stimulation in some geological contexts, notable progress has been achieved recently through microseismicity monitoring, which has become widespread in EGS projects thanks to lessons learned from nonconventional oil and gas developments. Using multistage stimulation techniques also makes it possible to stimulate selected reservoir zones sequentially, limiting the amplitude of potential earthquakes.

Furthermore, international co-operation on R&D initiatives such as the DEEP project (2021-2024) has supported the development of risk management solutions, for example advanced or adaptative traffic light systems (ATLSs) for reservoir stimulation and operation. ATLSs consist of probabilistic tools that allow operators to adapt stimulation flow rates and pressures to avoid larger-magnitude earthquakes. They dynamically assess and model induced seismicity risks, informed by a range of real-time data and parameters. While such ATLSs have been successfully tested in the Utah FORGE project, codifying and mandating the use of best practices will be crucial to reduce the risk of induced seismicity in future developments.

Drilling

Drilling for geothermal resources is technically similar to oil and gas drilling. Economically, time on site is the main predictor of overall cost, highlighting the importance of drilling efficiency and good well design in both cases. In the business model for geothermal developments, the period required to generate a cash flow is longer than for petroleum production, making it even more imperative to reduce drilling time.

Efforts to reduce drilling-associated costs focus on (i) increasing penetration rates; (ii) extending drill-bit lifetime; and (iii) improving supply chain efficiency and logistics to accelerate operations and reduce downtime. Leveraging knowledge and experience from the oil and gas industry, in addition to expanding research and development, can help achieve these goals (see Chapter 3).

Additional innovation will also be required for successful resource utilisation in deeper and hotter reservoirs (sometimes referred to as superhot rock systems[12]), where supercritical fluids offer a significantly higher energy yield than traditional water- and steam-based systems. The successful harnessing of superhot rock energy is being tested in several regions, including through the upcoming demonstration projects of Reykjavík Energy (Iceland), GNS Science (New Zealand) and Mazama Energy (United States).

[12] Generally refers to extremely deep, high-pressure rocks above ~373°C – the temperature at which water is in a supercritical state.

However, high temperatures create significant technical issues for drilling and completion equipment and materials. Corrosive water, rock that is hard and brittle, and long drill paths all compound problems and require innovative solutions. Drilling jobs also need to be carefully planned and executed to avoid risks associated with pulling out of hole, pore pressure, and formation damage.

Running cooling fluids while rotary drilling and using compact polycrystalline diamond bits, for example, are solutions being developed and tested. Hybrid conventional and no-contact drilling technologies are also under development (see box below). They involve using and regulating drilling fluids (usually water based) to manage drilling operations and potential issues related to pressure control, well structure, frictional forces and circulation loss. Insulated pipes and mud chillers are also being employed and enhanced to protect equipment from long exposure to high temperatures.

Emerging drilling technologies and concepts

High-pulsed-power drilling

By initiating an electrical discharge within the rock, high-pulsed power (HPP) induces fractures through tensile forces using significantly less energy than traditional or alternative methods that rely on compressive force or heat to break or melt the rock. When the HPP drilling technology is combined with conventional drill bits, the HPP pre-cracks the rock before the drill bit fragments it, resulting in much faster penetration and extended drill-bit life, substantially reducing drilling costs.

Thermal-shock drilling

Researched by Japanese scientists, this method involves giving rocks "thermal shocks" by rapidly heating and cooling them. The temperature changes create cracks in the rocks, making them easier to drill. Thermal shocks weaken the structural integrity of the rock, allowing more efficient penetration. This technology is still in its early stages, and testing has been done to depths of a few dozen metres.

Millimetre-wave laser drilling

Combining millimetre-wavelength lasers with traditional rotary drilling is a hybrid method that breaks down rock material at the drill bit-rock formation interface, speeding up the drilling process and reducing the overall cost of accessing geothermal resources.

Percussive drilling

Combining traditional rotary drilling with percussive action is another augmented drilling method being tested. By "hammering" into the rock as the drill rotates, drilling is more efficient and thus quicker. One commercialisation effort is the Geovolve Hammer.

High-pressure water jet-assisted drilling

Developed by researchers in France and the United Kingdom, this method uses high-pressure water jets to cut rock into specific shapes that can then be broken apart more easily by fluid-powered percussive hammers. Still in the lab-testing phase, field tests may be deployed next year to demonstrate how it can be used to improve drilling rates.

Directional steel-shot drilling

Currently being tested in the Netherlands, this technology incorporates the release of steel-shot particles under high pressure to erode the formation and reduce resistance to subsequent rotary drilling.

Plasma-based drilling

This method can use electrical discharges to create a plasma torch with high-temperature gas to disintegrate rock directly. The technology can be also integrated with mechanical drill bits to weaken rock. These technologies are typically at the laboratory or early testing stages.

Well completion

Well completion involves readying a drilled well for production by preparing the wellbore, installing production tubing and downhole tools, and performing any necessary perforation and stimulation. Many completion technologies are adequate or can be simplified for many geothermal applications, although continuous flow of liquid and steam can also cause mechanical issues, and the fluids may contain acidic or scaling components that degrade, foul or occlude surfaces and openings.

Temperature-resistant downhole tools are also essential for reservoir evaluation, and research and development funding and trialling is ongoing. As logging tools and samplers need to be able to withstand high temperatures and corrosive conditions, service providers are increasingly designing and offering adapted equipment. Meanwhile, national laboratories and energy companies are developing high-temperature-resistant optical fibres, creating new approaches to downhole measurement. Well-testing processes and software tools also need to be adapted to gain a complete understanding of a geothermal reservoir's overall potential as flow and pressure-transient tests are performed and as temperature, pressure and flow rate are monitored.

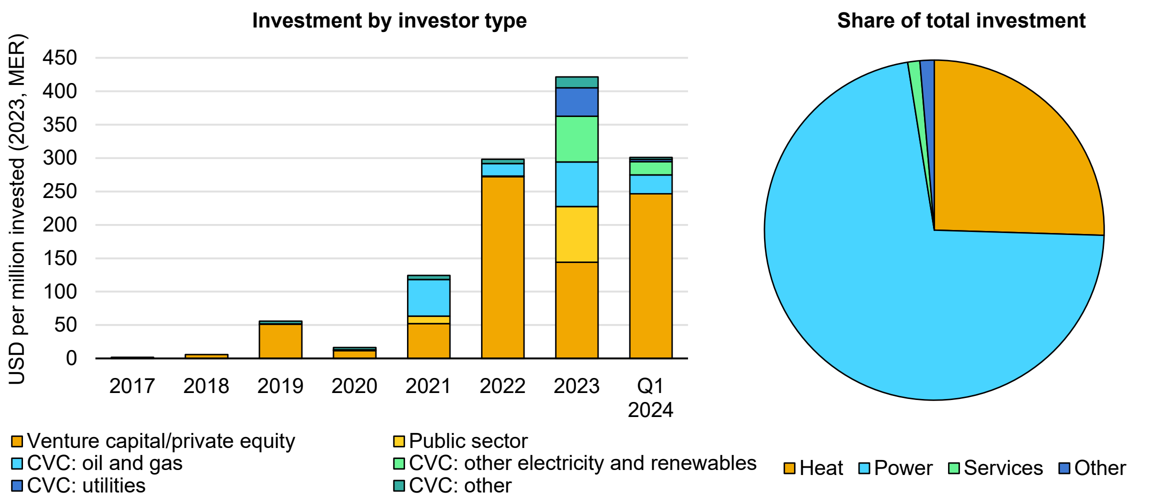
Investment in next-generation geothermal innovation

Early- and growth-stage investment in companies focused on next-generation geothermal technology development is key to achieve economies of scale and improve cost competitiveness. Since 2017, investments (mainly from venture capital firms, the public sector and corporations) have risen from negligible amounts to over USD 420 million per year in 2023 and are expected to expand further as interest grows in 2024, supporting the momentum for next-generation geothermal technologies. In the last five years, power generation projects received nearly 75% of total global funding, with the remainder allocated to heat production, including both district heating and innovative business models for shallow-heat applications.

Most investments in innovation and startup companies have been concentrated around just a few pioneering EGS and AGS enterprises since 2021. Together, Fervo (for EGSs) and Eavor (for closed-loop systems or AGSs) have closed financing for more than USD 700 million, accounting for over 60% of early- and growth-stage investments since 2021. In addition to investments from venture-capital firms and corporate financing, public funding has helped geothermal startups improve, test and expand their technologies. For instance, the United States, Canada and Germany have all provided public support to EGS and AGS companies, and to drilling and technology service providers.

Given the considerable synergies between the oil and gas and geothermal sectors, oil and gas companies have invested nearly USD 140 million in EGS and AGS development. For heat, GIC (a public entity that partly manages Singapore's foreign reserves) invested USD 240 million in Arctic Green Energy to help develop district heating in Europe and Asia. Projects to extract lithium from geothermal brine have also garnered similar levels of interest from public and private companies (see Chapter 4).

Annual geothermal investments by investor type and investment shares by sector, 2017-Q1 2024



Notes: CVC = corporate venture capital. Direct lithium extraction investments are excluded.

Source: IEA analysis based on Cleantech Group data.

Venture-capital (VC) and private-equity firms have been the most active in financing next-generation geothermal developments such as EGSs and AGSs. While venture-capital portfolios do not shy away from high risk (about 5% to less than 10% of investments typically account for most of a firm's returns), project rewards need to match risk levels. Clean-tech investments, particularly in geothermal, often rely on higher amounts of capital, and project development and trialling is several years longer than for clean-tech software technologies before moving into long-term demonstration trials or demand testing.

The higher risk levels, longer timelines and lower upside potential of many new geothermal projects contrast with the typical VC-style investment focus areas (e.g. internet, software and telecommunications). Meanwhile, oil and gas companies, more familiar with the time frames and risk level of geothermal development, seek a higher return profile than is typically associated with geothermal projects.

Because of uncertainties about demand and consumer willingness to pay, the time gap between the early investment stage and the geothermal demand testing phase is considerable. Since investments and purchase agreements from large data firms e.g., Google, Microsoft indicate demand pull from data centres, government support to implement demand-side incentives could encourage geothermal development by further reducing demand-side risks.

Ultimately, the goal of venture-capital investors is to secure returns on their investments within the lifespan of a VC fund (typically 10 years), meaning that they need to be able to sell onward into a market. The oil and gas and utility sectors are obvious sell-forward targets, with the venture-capital arms of oil and gas utility service companies having shown a willingness to invest in technologies. The crossover between geothermal and oil and gas is clear, allowing service companies to capitalise on technology bets across sectors.

However, for the geothermal sector to advance substantially, it needs a market to sell into. The oil and gas sector bridges the gap to financial markets with practices such as reserve-based lending and detailed resource reporting, which create transparency for financial markets that may serve as a reference for the geothermal industry.

Geothermal resource classification can increase data transparency and facilitate financing and transactions

Very similar to oil and natural gas exploitation, geothermal resource development can be associated with significant geological, technical, socioeconomical and financial risks. While parallels with the oil and gas sector are numerous, geothermal resources span more reservoir types, are renewed to differing degrees, and may be exploited by very different technologies. Geothermal reserve and resource assessments therefore require a platform through which project risks and opportunities can be communicated to support countries, developers, investors and insurers.

In the oil and gas sector, robust resource characterisation systems have been developed, primarily the Petroleum Resources Management System (PRMS) for general principles and the US Security and Exchange Commission (SEC) for reporting rules. Both provide consistently applied approaches to estimate oil and gas quantities and evaluate the economic feasibility of projects, and they are widely accepted globally for oil and gas reserve classification and categorisation. Reserves are reported openly, and the auditable reports form the basis for the oil and gas sector to communicate company potential to financial markets.

The geothermal industry has developed several reporting standards, for example those of the Australian Geothermal Energy Association/Australian Geothermal Energy Group (2008; revised 2010) and the Canadian Geothermal Energy Association (2010). Potential ambiguities and subjectivity in these standards catalysed development of the 2016 *Supplementary Specifications for the Application of the United Nations Framework Classification (UNFC) for Resources to Geothermal Energy Resources* (revised 2022). In 2022, Queensland, Australia, became the first government body to adopt the UNFC geothermal framework.

The UNFC framework addresses evaluation of a geothermal project's environmental and socioeconomic viability and the technical feasibility of developing project resources, independent of the mineral or energy type being considered. Challenges remain, though, given the complexity of geothermal resource assessments. In 2017, 14 geothermal case studies were published and in 2018-2019, participants attended workshops to apply the UNFC guidelines to geothermal applications in Indonesia, the Caribbean and Ethiopia. The workshops determined that "there are still a few challenges to solve within the UNFC system that pose specific issues for classifying geothermal energy resources, such as the quantification of the geothermal resource, as this requires a method that is not yet universally accepted and applied."

This is one of the primary reasons the investment community has not yet adopted the UNFC framework as the common language for merger and acquisition transactions and for raising capital for geothermal projects – even though the UNFC system can be as rigorous as the PRMS and SEC guidelines. Bridging documents have been developed to adapt mineral and energy sector standards to the UNFC reporting matrix, but they have not been employed globally.

As new geothermal extraction techniques such as EGSs and AGSs mature, support is needed for the geothermal sector to develop technology-specific guidelines to estimate economically recoverable reserves. Similarly, the oil and gas sector continues to adapt to "unconventionals", having released new guidelines for unconventional resources as recently as 2022. The geothermal sector could benefit from further support to harmonise resource characterisation and project assessment frameworks and enable further adoption across all stakeholders.

Chapter 3: The oil and gas industry and geothermal

Introduction

The oil and gas industry could be instrumental in encouraging future geothermal developments. The industry has extensive knowhow in handling liquids and gases; large financial resources; substantial research and development expertise; technical and operational knowledge; and proficiency in executing and managing large, capital-intensive projects. In fact, oil and gas industry innovations (most notably the honing of hydraulic fracturing and directional drilling techniques for tight oil and shale gas developments in North America) have already been foundational for the development of next-generation geothermal technologies.

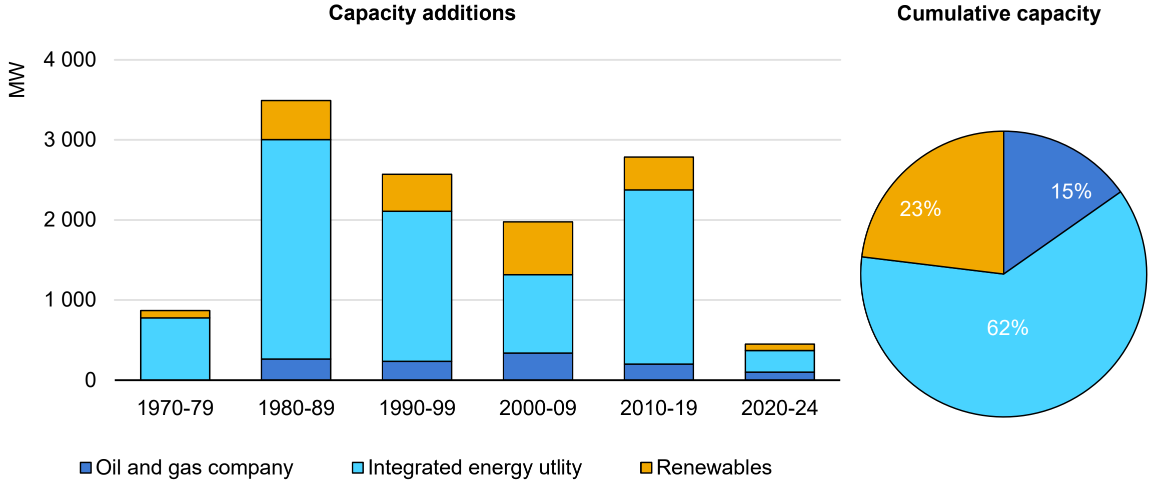
Applying the oil and gas industry's expertise and resources more widely to geothermal technologies could therefore expand their potential and reduce their costs significantly. Diversifying into geothermal energy could also be of great benefit to the oil and gas industry, providing not only a hedge against possible future declines in oil and gas demand but also opportunities to grow new business areas in the emerging clean energy economy.

In this chapter, we first examine the oil and gas industry's role in developing and operating current geothermal projects. We then explore overlapping technical competencies and financial synergies between the oil and gas and geothermal industries and estimate the extent to which oil and gas industry skills and resources can reduce the cost of future next-generation geothermal projects.

Role of oil and gas industry to date

Oil and gas companies have long recognised the potential of geothermal energy, but today pure-player geothermal developers and utilities own the vast majority of installations. Only around 15% of capacity is operated by oil and gas companies, as parent entities, through subsidiaries, ownership stakes in startup companies, and joint ventures. A much greater share is owned by integrated energy utilities that have expanded their natural gas and electricity portfolios to include geothermal energy.

Company ownership of global geothermal power plant capacity



Notes: Data represents the top 70% of operational power plants. “Renewables” includes companies developing solar, wind, hydro and geothermal assets.

Sources: IEA analysis based on S&P, Global Energy Monitor and company reports.

Among the largest oil and gas companies with direct or subsidiary ownership of geothermal assets are Pertamina Geothermal, Star Energy and Chevron, each possessing over 200 megawatts (MW) of capacity in Indonesia, while OMV, the Austrian integrated national oil and gas company, is developing the 20-MW Aspern geothermal project. Joint ventures with oil and gas companies include the Sarulla partnership involving Medco, Inpex, Otuchu, Kyushu and Ormat, which holds over 300 MW of capacity in two plants in Indonesia.

Many geothermal energy producers also have existing stakes in gas power infrastructure. For example, Calpine, the world’s largest geothermal power producer, also owns and operates gas-fired power plants; Engie is a large investor in geothermal district heating and cooling solutions in France; Sinopec has around 4 000 MW of geothermal heating capacity. There are also examples of natural gas distribution companies developing geothermal projects (e.g. Eversource in the United States) through partnerships.

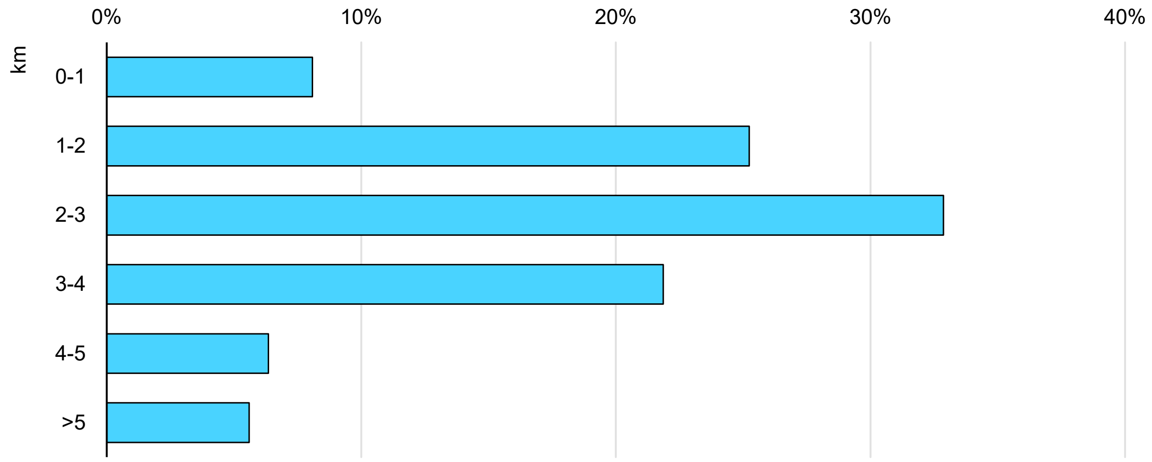
Oil and gas service providers are also engaged in geothermal developments and operations, including drilling-related services, completions, wellsite and downhole measurements, and laboratory studies. In fact, several such providers with core competencies in oil and gas have diversified into providing specialised equipment for geothermal operations. For example, SLB was granted USD 10 million to develop a system to monitor the long-term integrity of completions in geothermal wells, and other companies including Weatherford, Expro, and Halliburton are involved in various geothermal operations, including managing flow assurance, high pressures and temperatures to improve well performance. Similarly, Baker

Hughes has established a consortium to develop and test next-generation geothermal-based power production. Drilling contractors can also play an important role in geothermal asset development, with Helmerich & Payne and Nabors, for example, investing in a number of geothermal companies.

Overlapping competencies in the oil and gas and geothermal industries

A number of skills, data, technology and supply chain elements are transferrable between the oil and gas and geothermal sectors for both conventional and next-generation technologies, and many of the staff in geothermal companies today were formerly oil and gas workers. Developing new geothermal projects requires subsurface evaluation, modelling, drilling and surface operations, similar processes to those used in many upstream oil and gas projects. Oil and gas service companies are becoming increasingly engaged in the technology, design and workflow aspects of geothermal asset development. The oil and gas industry most often produces oil from reservoirs up to 4 kilometres (km) depth, and it is increasingly targeting deeper zones that contain very large geothermal potential (see Chapter 2).

Share of global oil production in 2023 by reservoir depth



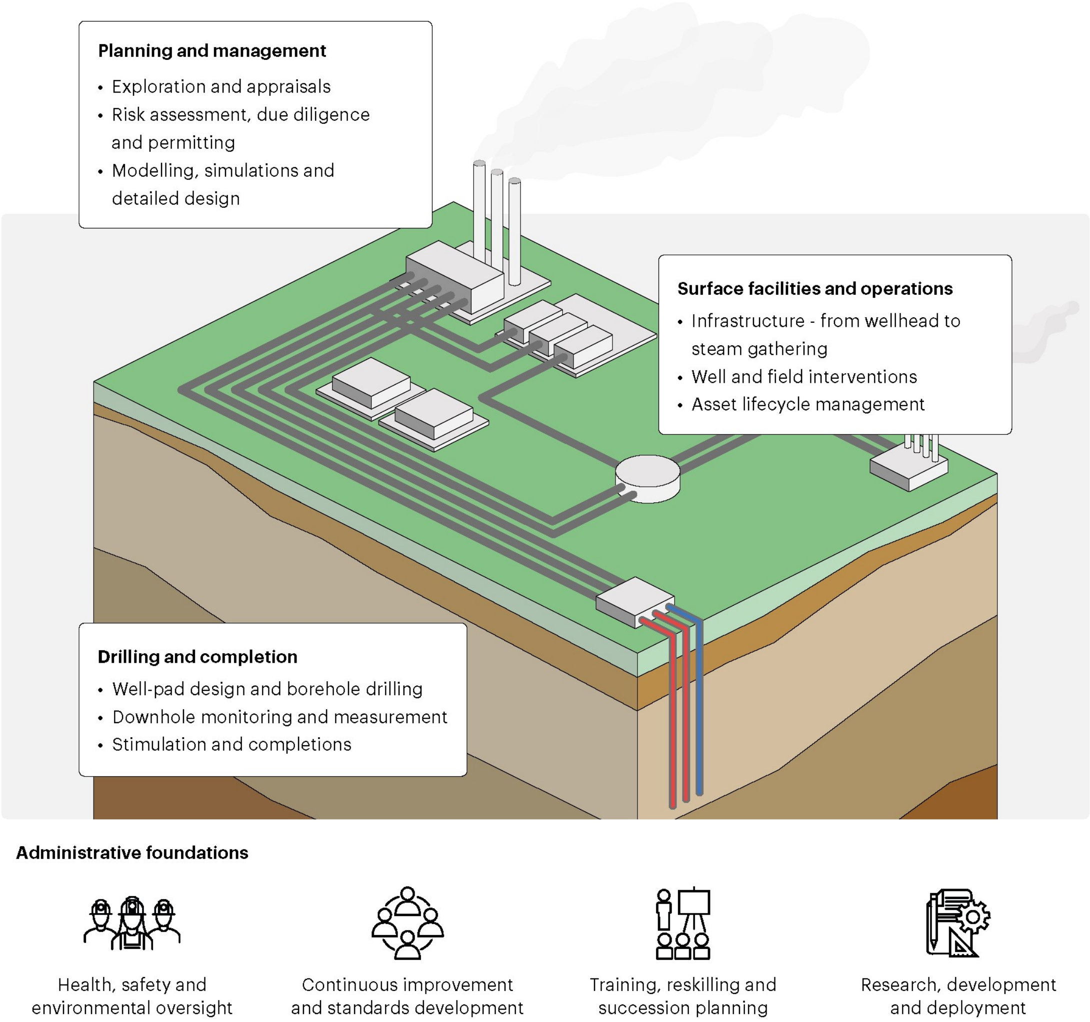
Sources: IEA analysis based on Rystad Energy.

Oil and gas industry expertise and resources could be particularly important for the development of next-generation geothermal technologies: indeed, enhanced geothermal systems (EGSs) rely on well stimulation, including hydraulic fracturing and directional drilling techniques that were refined for shale gas and tight oil operations in the United States. Advanced geothermal systems (AGSs) similarly rely on high-precision directional drilling to create closed-loop systems deep in the

Earth's subsurface. Both conventional and next-generation geothermal projects depend on highly specialised systems and equipment to manage the high-pressure high-temperature environments required to generate sufficient geothermal power and heat outputs.

Regarding operations, many techniques to optimise geothermal output, monitor facility integrity, improve safety and repeatability, and intervene in well underperformance are built on practices from oil and gas operations. The stringent health, safety and environmental management practices of the oil and gas industry, as well as its design and engineering principles, would also be of great benefit to next-generation geothermal projects. The industry is also well placed to participate in the research and development needed to develop next-generation materials, chemicals and stimulation techniques.

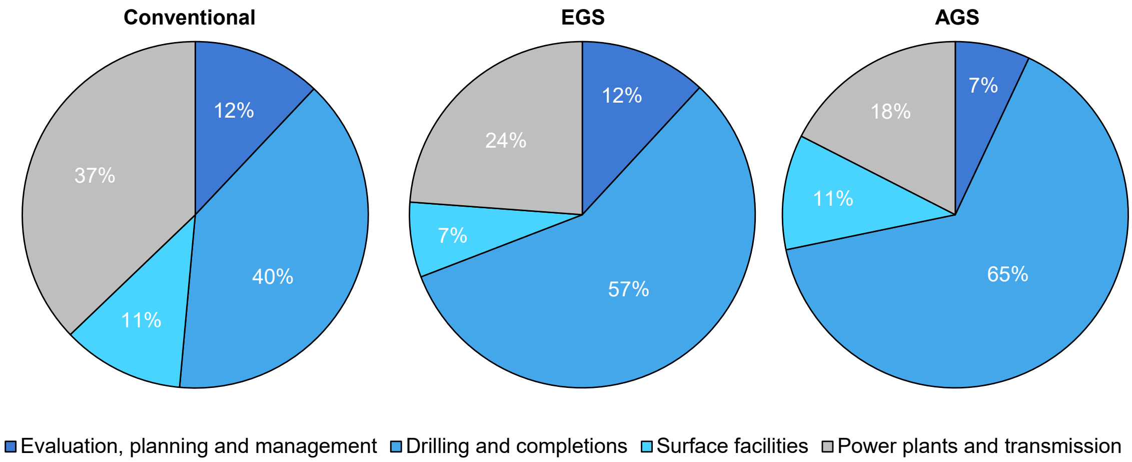
Overview of oil and gas and geothermal industry synergies



IEA. CC BY 4.0.

Some of the largest overlaps between the skills and expertise of the oil and gas industry and geothermal projects apply to project evaluation, planning and management; drilling and completion; surface facility construction and maintenance; and operations and production monitoring. After examining all investment components involved in these stages in detail, we estimate that an average of around two-thirds of every dollar invested in conventional geothermal operations has a significant overlap with the oil and gas industry. For next-generation geothermal technologies, we estimate that more than three-quarters of the required investment is closely related to oil and gas industry skills and expertise.

Shares of conventional and next-generation geothermal technology investments that overlap with oil and gas industry skills and expertise



Notes: EGS = enhanced geothermal system. AGS = advanced geothermal system.

Sources: IEA analysis based on NREL, IRENA and EGEC reports and publicly available research papers.

Evaluation, planning and management

The ability to understand and develop subsurface resources underpins all oil and gas and operations. In both industries, project evaluation begins with geological and geophysical studies to assess resource availability and viability. Oil and gas projects rely on seismic surveys, borehole logging, coring and testing and reservoir simulations. Geothermal projects use similar techniques, including thermal gradient and resistivity surveys to estimate subsurface temperatures. In each case, the evaluation phase is critical to determine potential economic returns on investments over the lifetime of projects, which shapes project planning and helps mitigate risks tied to exploration and drilling.

Additionally, project planning and management in both industries draw on comparable technical expertise and infrastructure. Project management challenges, such as permitting, environmental impact assessments and stakeholder engagement, are also similar in both sectors.

Drilling and completions

The depth and complexity of subsurface operations for both oil and gas and geothermal operations vary depending on geological conditions and the technologies chosen. Conventional geothermal projects typically target shallower zones than conventional oil and gas ventures do. In contrast, EGSs and AGSs require deeper wells and larger boreholes, and are often drilled into harder rock, requiring more advanced drilling techniques. EGSs also make use of techniques adapted from the well stimulation and directional drilling programmes refined by the tight oil and shale gas industry.

In the drilling phase of geothermal projects, oil and gas expertise could be leveraged in many areas. For example, improved surface and downhole data collection could reduce drilling times, increase drill bit life, and improve penetration rates. Better design and retention of drilling muds could improve the efficiency of drilling operations and enhance wellbore stability in geothermal projects. Expertise in reservoir evaluation techniques – possibly assisted by artificial intelligence tools – including geological and reservoir modelling, real-time wellbore measurements, pressure testing and fluid sampling, would strengthen geothermal assessments and decision making.

Nevertheless, there are also some differences between geothermal and oil and gas operations. Whereas most conventional geothermal and EGS energy production methods require constant fluid reinjection to dispose of produced fluids while maintaining reservoir pressure and fluid circulation, a similar process is used in only some, but not all, oil and gas developments. While oil and gas wells are typically at their most productive during the first few years of their lifetime before flow rates deteriorate, geothermal wells are expected to operate continuously at a consistently high rate for their 20- to 30-year lifetime, while retaining their integrity.

Furthermore, deeper geothermal wells are subject to prolonged high temperatures and sometimes corrosive fluids, so equipment must be made of specialised corrosion-resistant materials. Geothermal projects may also require specially designed drill bits that are robust enough to open wider boreholes on very hard and hot rocks; oil and gas operations often also involve high-pressure conditions, but not always sustained high temperatures. High temperatures are particularly challenging for electronics, wireline logging tools and directional drilling equipment.

Surface facilities and ongoing operations

Much of the surface-level infrastructure employed by the oil and gas industry could also be used or repurposed for the geothermal industry. For instance, equipment such as pumps, well pads, heat exchangers, separators, cooling systems and control software are all needed for both industries. Pipeline and fluid-handling systems are also common to both sectors.

For both oil and gas as well as for geothermal, continuous monitoring of wells helps optimise energy output and prevent resource depletion or environmental impacts such as land subsidence or thermal pollution. Maintenance schedules, performance tracking and periodic well reinjection are also necessary to ensure the resource's longevity and maintain environmental compliance. Proper management is essential to maximise a project's lifespan and adapt to any changes in subsurface conditions over time.

Some factors related to operational safety are also common to both industries, although their degree of importance varies due to the different physical and chemical conditions of the operations. All drilling procedures create exposure to multiple risks and hazards, including dangerous fluids, high pressures and equipment degradation. The oil and gas industry also handles flammable hydrocarbons, which necessitates well-defined and rigorously enforced regulations governing site operations. Whereas geothermal operations mostly involve water and steam rather than hydrocarbons, the fluids may nonetheless contain dissolved acids and ions, which may pose health hazards and can also cause corrosion and reactions that need to be monitored and managed.

Leveraging oil and gas industry expertise to reduce geothermal costs

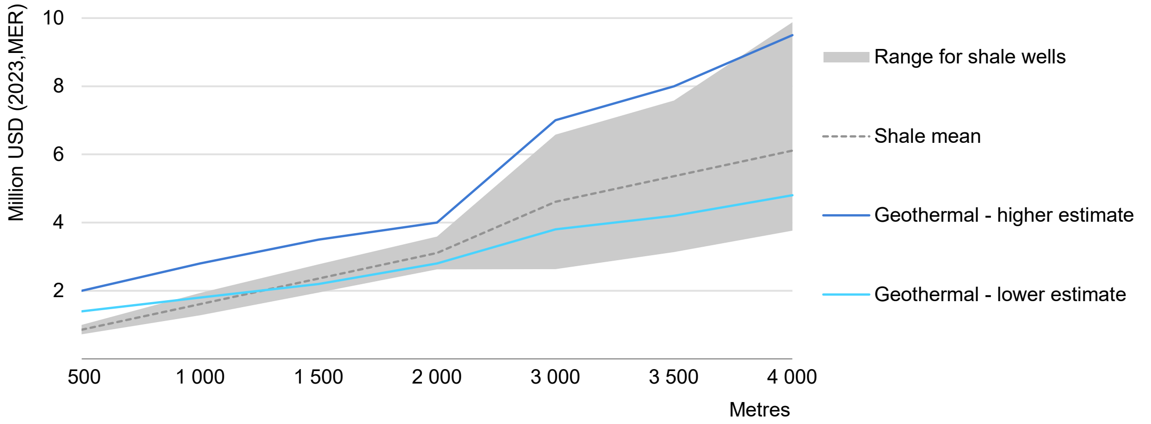
Current costs of geothermal technologies

The cost of providing district heating through conventional geothermal installations is currently close to USD 3 000/kW. However, EGS costs of up to USD 15 000/kW in 2024 are already significantly lower than in recent years thanks to the wider adoption of drilling and completion techniques honed by the oil and gas industry.

EGS and AGS cost ranges are wide because the expense of drilling a geothermal well is highly dependent on location and subsurface characteristics, and the availability of skilled workers and materials. Lateral length, hole and pipe diameters and the need for specialised casing or drill bit technologies can change the overall cost of a single well dramatically (for example, needing to use higher-grade alloys that can withstand corrosive media for an extended period can increase a drilling programme's capital expenditures). Specialised inhibition chemicals may also be required, adding to operating costs.

Another key parameter is drilling depth. The number of geothermal wells drilled to date is a very small fraction of total shale wells (which number in the hundreds of thousands), but it is nonetheless informative to compare published cost estimates for both. At depths of up to 2 000 metres, we estimate that currently geothermal wells can cost around 40% more than an average shale gas well. At depths beyond 2 000 metres, however, geothermal wells appear to fall within the relatively wide cost range of shale gas wells.

Well drilling and completion costs by drilling depth, enhanced geothermal vs shale gas in the United States



Sources: IEA analysis based on data from Rystad and NREL.

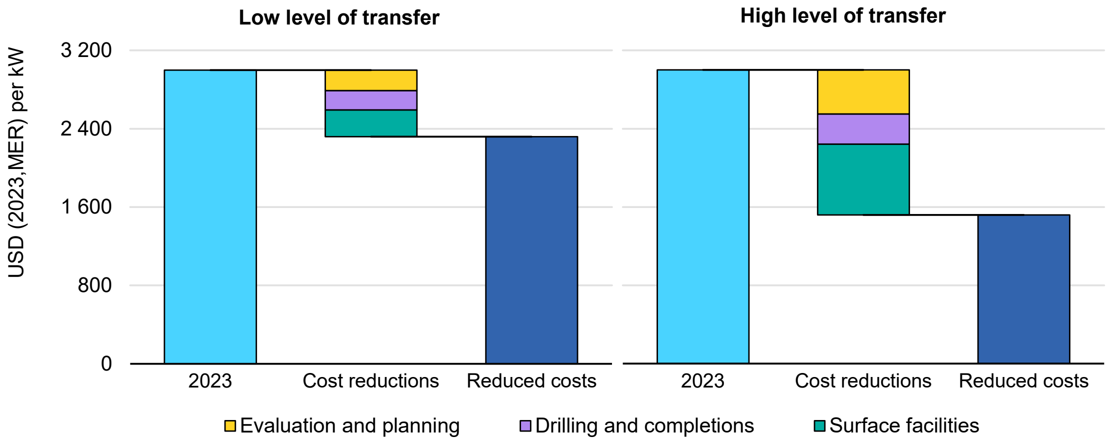
Potential cost reductions

Applying existing oil and gas technologies and services more widely could significantly reduce the overall cost of deploying geothermal technologies. Building on existing work, we have estimated potential conventional-geothermal and EGS costs savings by modelling reductions achieved by using oil and gas technologies, practices and lessons learned across various project phases (from evaluation and planning through drilling).

Our estimates include spillover benefits from the direct adoption of current oil and gas technologies; economies of scale achieved by applying existing oil and gas practices; and application of the industry's extensive research and development capabilities to geothermal developments. We examine two scenarios: the first involves the full transfer of oil and gas knowledge and practices, and the second is based on a low level of knowledge transfer, characterised by less systematic application of these opportunities as well as longer implementation times.

For conventional geothermal systems, we estimate that applying a high number of practices from oil and gas operations during the evaluation and planning phases could reduce costs by nearly 15%. Scaling up surface practices through modular repetitive design and improving drilling efficiencies through the widespread application of oil and gas technologies could provide a further 35% reduction in costs.

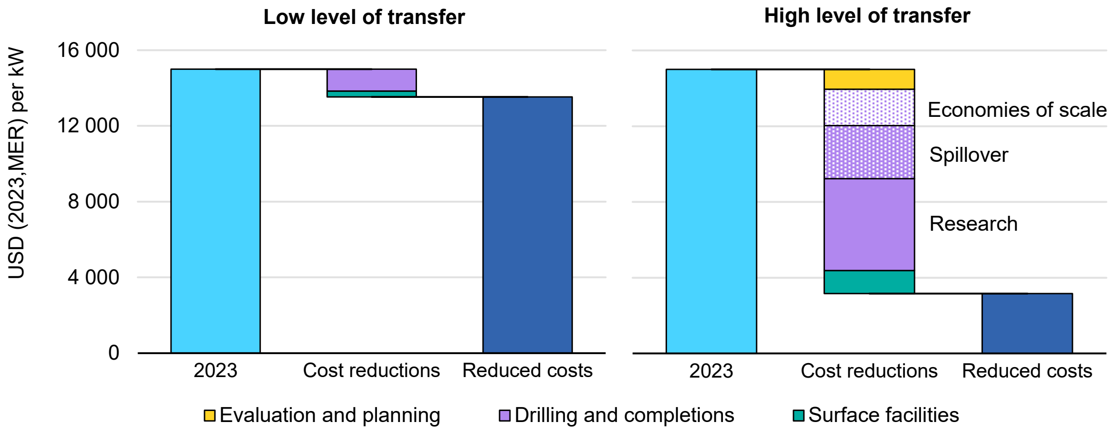
Conventional geothermal cost reductions from the transfer of oil and gas industry expertise



Sources: IEA analysis based on data from NREL SAM tool for EGSs; IRENA and EGEC reports; and publicly available research papers.

For EGSs, widespread knowledge transfer from the oil and gas industry as well as additional research support to acquire and improve reservoir data, processing and modelling during the evaluation and planning stages of geothermal projects could reduce costs by around 10%. During drilling and completions, the extensive use of practices that are now standard in tight oil and gas reservoir development could reduce costs by 20% and scaling up the use of multi-pad well designs could reduce them a further 10%. Furthermore, researching and developing the use of new equipment and working fluids could reduce costs an additional 30%.

Enhanced-geothermal cost reductions from the transfer of oil and gas industry expertise



Sources: IEA analysis based on data from NREL SAM tool for EGSs; IRENA and EGEC reports; and publicly available research papers.

In total, we estimate that a high level of knowledge transfer and productivity gains from the oil and gas industry could reduce conventional-geothermal technology costs by up to 50% and next-generation costs by nearly 80%. This would make next-generation technologies cost-competitive and would be a key factor in future growth (see Chapter 4).

Repurposing oil and gas wells for geothermal energy production

There is an opportunity for oil and gas wells that have been abandoned, are underperforming, or are nearing the end of their technical lifetime to be repurposed to generate geothermal energy. Doing this would allow developers to use existing infrastructure and past data from seismic surveys and downhole measurements to avoid some drilling and completion costs, help derisk geothermal projects, and improve success rates.

Indeed, a number of pilot projects have already demonstrated the feasibility of repurposing oil and gas wells in this way. For example, in 2020 GreenFire Energy retrofitted an existing oilwell in United States, in 2021 MS Energy Solutions converted an abandoned oilwell to geothermal operations in Hungary, and in 2023 CeraPhi converted an abandoned gas well to geothermal operations in the United Kingdom.

Whether oil and gas wells are suitable for repurposing in this way depends on the availability of sustained and large heat gradients; sufficient flowrates; proximity to demand centres; and a flexible permitting system that allows an oil and gas licence to be converted to geothermal operations. There is also a need to ensure the ongoing integrity of old wells, which may be subject to lifetime durability challenges under new flow regimes and chemistries, in addition to corrosion, erosion and scaling problems. Another issue is that workover costs – e.g. to restimulate a well – are often relatively high.

Furthermore, it is important that normal abandonment protocols are not bypassed when oil and gas wells are converted to geothermal energy production. This means that wells still need to be properly sealed and decommissioned to prevent methane leaks and respect environmental standards.

Skill development and implications for workers

Transferability of today's workforce

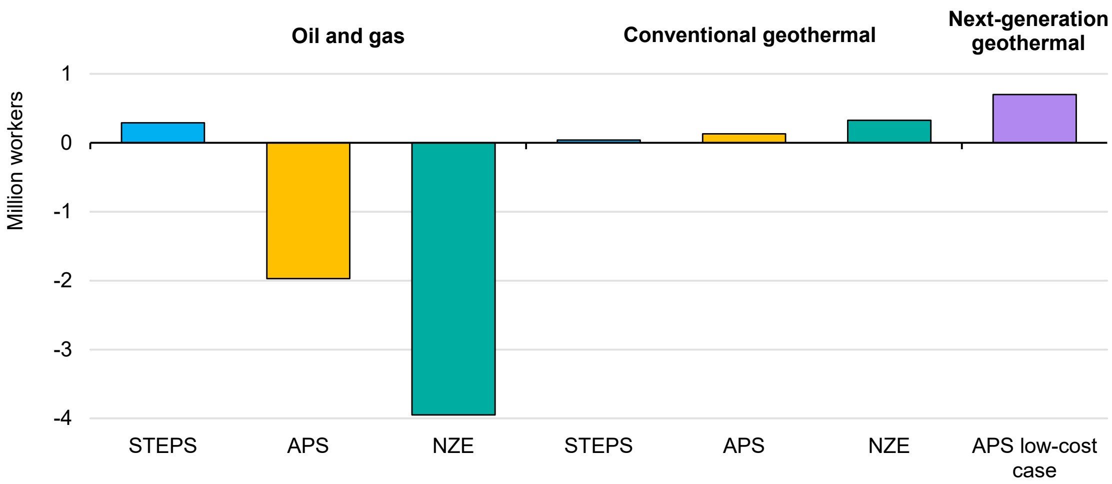
The oil and gas industry currently employs about 12 million workers globally – much more than the geothermal industry, which provides around 145 000 jobs. In the oil and gas sector, employment ranges from professions such as geoscientists and engineers measuring and modelling the occurrence of hydrocarbons and how they can be economically produced, processed and sold, to tradespeople who perform drilling operations and work in refineries and gas facilities, to functional workers with roles in health and safety, the supply chain, and research and engineering. Among these positions, the majority of current oil and gas workers have skillsets that could transfer directly to the geothermal sector, bolstered by supplementary training and familiarisation with the different health, safety and environmental risk profiles associated with geothermal operations.

As the world transitions to clean energy sources, projected production declines heavily influence IEA outlooks for oil and gas employment. In the Stated Policies Scenario (STEPS), oil and gas sector employment remains broadly constant to 2030, with a 5% increase in emerging markets and developing economies largely offset by a 10% decrease in advanced economies. In the Announced Pledges Scenario (APS), global employment in the oil and gas industry falls more than 15% (by almost 2 million workers) by 2030, and in the Net Zero Emissions by 2050 (NZE) Scenario it falls more than 30% (by just under 4 million workers).

Thus, whether due to their concerns over career security or a deliberate choice to support clean energy technologies, an increasing number of mid-career oil and gas workers are seeking opportunities to transition to alternative sectors, even though these sectors sometimes offer lower levels of remuneration. The possibility of working on geothermal projects is therefore an important option for these workers to continue using their experience and expertise.

In the STEPS, employment associated with conventional geothermal power development and operations increases by almost 30% globally by 2030, to just under 185 000 workers. Employment growth accelerates even further in other scenarios, increasing by 90% (to over 270 000 workers) in the APS during this period and more than tripling in the NZE Scenario, to over 470 000 workers. The potential is even greater in an upside case that includes next-generation geothermal development for electricity and heat production, representing 700 000 additional jobs by 2030 (see the low-cost case in Chapter 4). Combined, total geothermal employment could reach 1 million jobs by 2030 in the APS. As a result, we estimate that about 40% of the employees dismissed from the oil and gas workforce in the APS by 2030 could transition to the geothermal sector.

Total oil and gas and geothermal employment changes by scenario, 2023-2030



Notes: STEPS = Stated Policies Scenario. APS = Announced Pledges Scenario. NZE = Net Zero Emissions by 2050 Scenario.

Strengthening the geothermal talent pool

Future geothermal development will hinge on having a skilled, appropriately sized workforce in place. In the past, the geothermal sector has already benefited from an influx of well-experienced professionals from the oil and gas sector, including geologists; well, reservoir and petroleum engineers; and specialised tradespeople trained and practised in rig operations. The similarities among these disciplines have made it possible for the geothermal sector to leverage the learning and expertise gained in the oil and gas industry from decades of operation.

There are clearly significant overlaps in the worker skills required in the oil and gas industry and those needed in geothermal energy. From conducting seismic surveys to evaluating prospects, modelling flow dynamics and preventing corrosion, geothermal operations demand a robust technical foundation often acquired through degree programmes traditionally associated with the fossil fuel industry (e.g. Petroleum Engineering; Geophysics; Geology; and Earth Sciences).

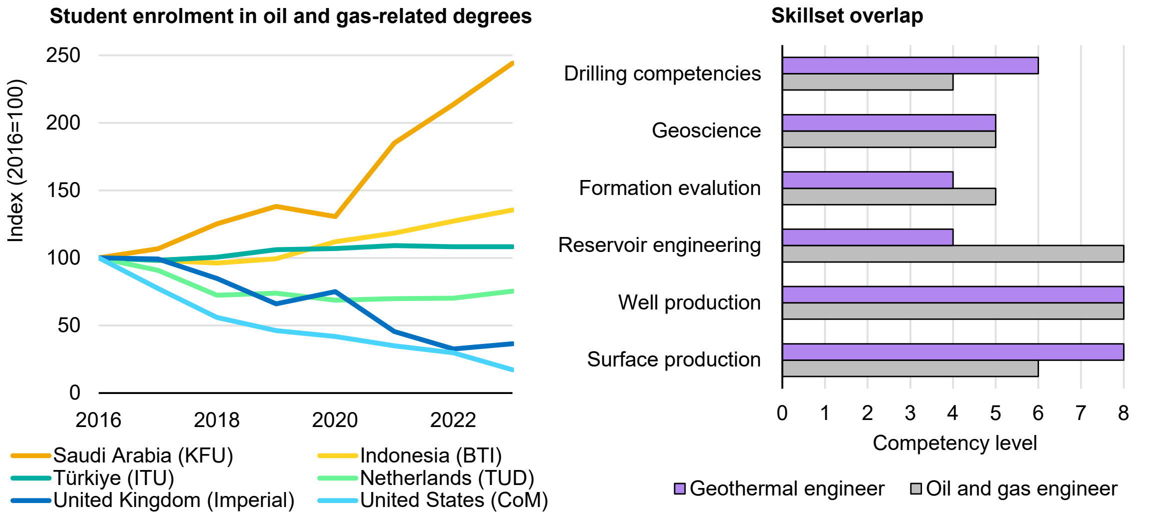
Petroleum engineering programmes are available globally, with over 100 offered. In the United States, more than 30 universities provide petroleum engineering degrees, but there are fewer dedicated geothermal engineering programmes. Iceland offers some specialised geothermal studies, but elsewhere geothermal courses tend to be embedded within civil, mechanical or environmental engineering departments rather than offered as independent degree tracks.

Enrolments in degree programmes traditionally associated with the fossil fuel industry are on an upward trend in producer economies (such as Saudi Arabia) and in countries where geothermal energy is already a recognised contributor to the national energy mix (e.g. Indonesia and Türkiye). Since around 2015, however, enrolments have fallen in a number of advanced economies, including the United States, the United Kingdom and the Netherlands, with declines of 25-80%.

Several factors are responsible for this trend, particularly anticipated lower demand by oil and gas companies for programme graduates. Climate change concerns are also growing, as is student activism protesting degrees linked to oil and gas operations. Without careful attention, this shift could have knock-on implications for the availability of skilled workers for clean energy development – including geothermal – that rely on similar technical and specialised knowledge.

There is great potential for the oil and gas sector to support university degrees, apprenticeships, training programmes, and regional and international centres of excellence more extensively. Setting a precedent for such partnerships is the recently announced Fervo Energy, Southern Utah University and Elemental Impact Geothermal Apprenticeship Program, which aims to help oil and gas workers transition into the expanding geothermal sector (e.g. 60% of Fervo Energy staff are former oil and gas workers). The US Department of Energy USD 165-million Geothermal Energy from Oil and Gas Demonstrated Engineering (GEODE) initiative also aims to brings oil and gas skills and engineering experience into the geothermal sector.

Enrolment in degree programmes that provide essential geothermal sector skills, 2016-2023, and skillset overlaps between geothermal and oil and gas engineers



Notes: KFU = King Faid University. BTI = Bandung Technology Institute. ITU = Istanbul Technical University. DUT = Delft University of Technology. Imperial = Imperial College London. CoM = Colorado School of Mines.

Sources: **Left:** IEA analysis based on university enrolment data and survey data collected by Lloyd Heinze for Petroleum Engineering and similar degree programmes. **Right:** IEA analysis based on SPE competency matrices; Okoroafor, E.R., C.P. Offor and E.I. Prince (2022), Mapping Relevant Petroleum Engineering Skillsets for the Transition to Renewable Energy and Sustainable Energy. Competency level: 2 = Awareness; 4 = Knowledge; 6 = Skill; 8 = Expertise.

Oil and gas and geothermal project financing

Geothermal projects require substantial upfront capital investment, typically financed through a combination of equity, debt, government grants and funds (e.g. the European Regional Development Fund and the Just Transition Fund) and tax incentives (e.g. the US Inflation Reduction Act). However, barriers to debt financing are often considerable due to early-stage exploration risks and the specialised nature of these ventures. Successful undertakings often use project financing, wherein a loan is secured against the project's future cash flows rather than the developer's balance sheet. This model requires a stable revenue stream, which is typically ensured through long-term power purchase agreements (PPAs) signed with offtakers.

Joint ventures have been a common strategy for oil and gas companies to enter the geothermal market, allowing them to provide part of the financing and spread the risk while also supplying both technical expertise and drilling equipment. Another entry method that can address corporate sustainability targets while allowing companies to retain full or majority ownership is the direct funding of geothermal projects through equity investments, including through corporate venture capital spending or capital allocated to renewable or low-carbon energy divisions.

Diversification into geothermal energy would also present oil and gas companies with an opportunity for long-term growth in clean energy and offer a hedge against volatility in oil and gas demand and prices.

Nevertheless, there are differences in the nature of oil and gas and geothermal ventures and expected returns. Oil and gas projects are often characterised by high – and volatile – returns, with companies looking to convert production into cash flows as quickly as possible. In contrast, geothermal projects with fixed offtakers are expected to pay back investments over a longer period of time with lower, but typically more stable, cash flows. Geothermal projects also tend to be much smaller than new oil and gas developments, limiting the opportunities to standardise, replicate and scale up, and this may discourage oil and gas companies from committing capital to them.

The oil and gas industry can help lower the cost of capital for risky geothermal projects by leveraging its presence in credit and debt markets, including by creating partnerships with commercial banks, issuing bonds or raising capital through other traditional means.

Ultimately, it is a balancing act for oil and gas enterprises to increase their financial commitments to the geothermal industry, as many traditional investors still expect these companies to provide high returns and may consider geothermal heat and electricity production to be too far outside their core competencies. Similarly, in the clean energy financing sphere, investors may regard oil and gas industry participation in geothermal projects with scepticism. Reconciling these differences is crucial to unlock more financial partnerships between stakeholders.

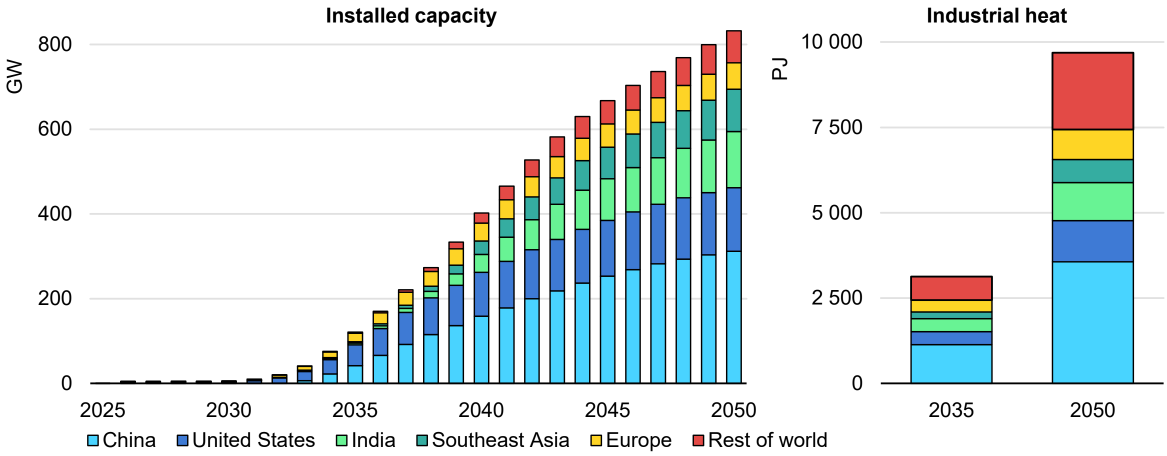
Chapter 4: Next-generation geothermal market potential

Overview

Introducing innovative technologies could create opportunities for next-generation geothermal energy all around the world. As nearly all countries possess geothermal resources, reducing the technology costs of advanced geothermal systems (AGSs) and enhanced geothermal systems (EGSs) could make it possible to tap into the enormous technical potential of geothermal energy (see Chapter 2). Like conventional geothermal systems, next-generation technologies offer several valuable products, including electricity, heating and cooling, and energy storage (see Chapter 1). Geothermal energy projects can also produce various critical materials such as lithium, which can enhance the business case for new projects. Next-generation geothermal could be an affordable option to generate low-emissions electricity domestically, tackling both security and decarbonisation goals.

In our detailed analysis of market opportunities, in regions with strong innovation and development support (i.e. such that it reduces technology costs up to 80% by 2035), we find global next-generation geothermal market potential of over 800 gigawatt (GW) of electrical capacity by 2050. We have also calculated market potential of over 10 000 petajoule (PJ) per year of heat production by 2050 for centralised heating systems (i.e. district heating) and industrial applications.

Market potential for next-generation geothermal power capacity and industrial heat by region, 2025-2050



On the pathway towards fulfilling country plans, targets and pledges, next-generation geothermal could deliver up to 15% of total electricity generation growth to 2050, though solar PV and wind would remain by far the largest sources of growth. This innovative technology could also ease pressure on developers attempting to realise the limited resource potential of other dispatchable clean energy technologies such as hydropower and bioenergy.

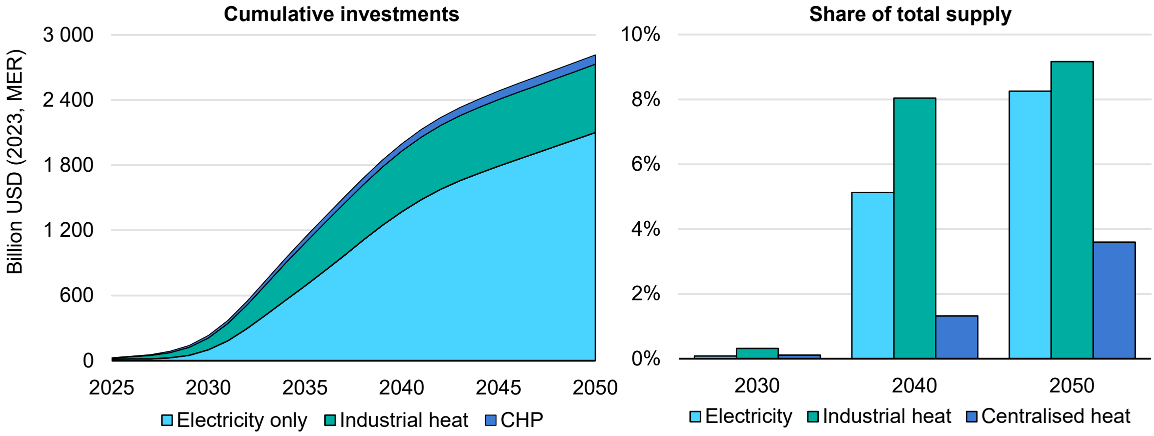
Next-generation geothermal could also compete with nuclear power and concentrating solar power (CSP) as well as solar PV and wind, reducing the need for battery storage and offering opportunities for more balanced clean energy transitions. For heat use, next-generation geothermal energy could replace fossil fuel-based heat generation in combined heat and power plants or boilers, while heat pumps are a key competing technology in cleaner energy systems.

We find that global market potential for next-generation geothermal is concentrated among just a few large markets, with China, the United States and India accounting for almost three-quarters. Due to its high degree of electrification and strong reliance on coal, China is the country that most needs to expand its clean energy sector to meet its goal of carbon neutrality by 2060. China is already on track to deploy huge amounts of solar PV and wind energy, but clean dispatchable power capacity needs to increase by nearly 650 GW over the next 25 years to maintain electricity security, of which close to half could be geothermal. Additionally, geothermal energy could meet a significant share of heating demand in buildings, through district heating systems and low- and medium-temperature processes in industry.

The United States is the second-largest market for next-generation geothermal technologies due to several factors: its clean energy transition is under way; it has high-quality geothermal resources; and it is a leader in geothermal innovation. In India – in addition to rapid solar PV growth – new clean dispatchable power capacity is needed to meet rising demand at all times and to avoid the construction of new coal-fired power plants.

Market potential is also significant in other regions including Southeast Asia, where rising incomes and economic development are rapidly raising energy demand. In Europe, clean energy transitions are in advanced stages, with a growing need for more dispatchable clean technologies to complement large volumes of wind and solar PV. Next-generation geothermal could also play a significant role in Japan, which has high-quality resources and significant opportunities to cut fossil fuel imports and enhance its energy independence. Countries in Africa (e.g. Tanzania and Kenya) could also benefit from developing their high-quality resources to generate baseload low-emissions electricity.

Market potential for next-generation geothermal, 2025-2050



Note: CHP = combined heat and power.

To fully develop next-generation geothermal market potential, total global investments would have to exceed USD 1 trillion by 2035 and USD 2.8 trillion by 2050. About 75% of the total would be invested in facilities to generate electricity. At its peak, annual next-generation geothermal investment nears USD 200 billion around 2035, when clean technology deployment is at full speed. This amount is equivalent to one quarter of today's total annual investment in clean electricity technologies.

With this investment, next-generation geothermal systems could provide up to 8% of the global electricity supply by 2050. The remaining portion of the investment, totalling over USD 700 billion, would be allocated to new next-generation geothermal facilities to produce heat, accounting for 4% of centralised heat and 9% of heat in industry.

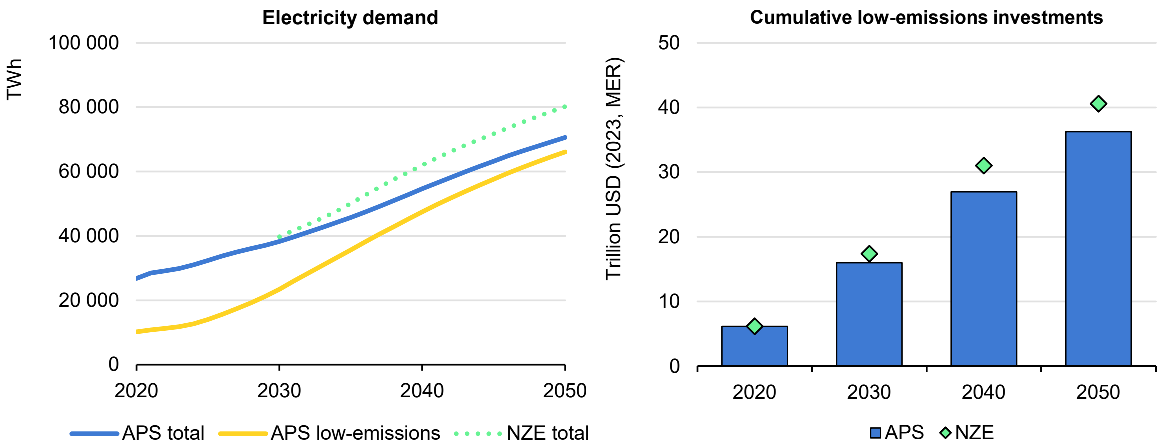
Next-generation geothermal for electricity

Significant clean-technology opportunities emerge as the electricity sector paves the way to clean and secure energy transitions

Global electricity demand is set to increase at six times the pace of total energy demand over the next decade, heralding a new age of electricity, as highlighted in World Energy Outlook 2024. One-third of this growth comes from China, although electricity demand is set to increase in all regions and will accelerate further in upcoming years thanks to growth in end-use electrification (e.g. electric vehicles and heat pumps) and rising industry, data centre and artificial intelligence (AI) consumption. By 2050, the share of electricity in final consumption reaches 40%

in the Announced Pledges Scenario (APS) to fulfil country-level plans, targets and pledges on time, and to over 50% in the Net Zero Emissions by 2050 (NZE) Scenario.

Electricity demand and low-emissions investments, 2020-2050



Notes: MER = market exchange rate. APS = Announced Pledges Scenario. NZE = Net Zero Emissions by 2050 Scenario.

Source: IEA (2024), World Energy Outlook 2024.

As shown in the APS trajectory, low-emissions technology deployment is ramping up quickly to keep pace with electricity demand growth and replace fossil fuels as countries work to fulfil their plans, targets and pledges on time. However, clean-electricity uptake would have to be even quicker to meet NZE Scenario aims. In 2050 in the APS, over 90% of total electricity is generated from low-emissions energy sources, while in the NZE Scenario the power sector is fully decarbonised. To achieve this transition, investments in clean technologies must increase rapidly, from just over USD 700 billion in 2023 to USD 1.6 trillion in 2030. Cumulative investments rise to USD 20 trillion by 2035 and USD 35 trillion by 2050 in the APS, with the NZE Scenario totalling USD 40 trillion by 2050.

As electricity systems expand to meet climate targets and ensure continued energy security, they will continue to rely on a suite of technologies. While solar PV and wind lead the way in clean energy transitions, a diverse set of resources that includes low-emissions dispatchable technologies such as geothermal, nuclear and bioenergy – along with energy storage – will be the basis of resilient electricity systems.

Some of the challenges to be faced are demand fluctuations, extreme weather events, irregular weather patterns, geopolitical tensions and supply chain risks. Recent technological advances in next-generation geothermal innovations, as detailed in Chapter 2, could create new market opportunities for the technology if its costs can become competitive with other low-emissions technologies.

Next-generation geothermal electricity costs

Construction costs and the levelised cost of electricity

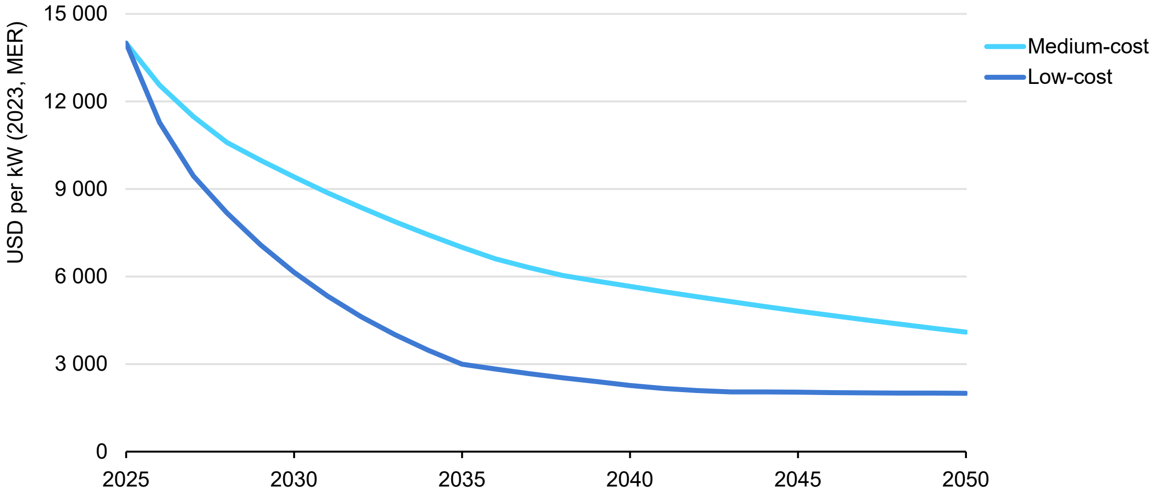
To unlock next-generation geothermal market potential for electricity generation, innovation and process improvements will be needed to reduce costs significantly. Minimising construction costs will be critical, especially by reducing subsurface expenses – namely for drilling – which today constitute an estimated 60-80% of the total, including for the power plant and all other infrastructure (see Chapter 4). These and other costs may be reduced partly by capitalising on synergies with the oil and gas industry, as many aspects of drilling operations, the supply chain and plant-sizing scalability are interrelated.

Today, the scope of construction costs for next-generation geothermal developments is broad, with only a handful of pilot projects online and the first commercial sites set to begin operations in the next few years (see Chapter 2). Differences not only in the depth and temperature of projects, but also in technology, lead to a wide range of expected costs. Estimated costs for first-of-a-kind EGS projects are in the order of USD 14 000 per kilowatt (kW), though applying the learning-by-doing principle can help reduce costs quickly. Compared with AGSs, it is easier to estimate costs for EGSs because they rely on fewer technological advances and multiple pilot projects have already been launched, whereas AGSs are even newer.

Strong and continuous support for next-generation geothermal innovation and development could drive construction costs down by as much as 80% by 2035, as represented in our low-cost case. However, when the transfer of experience from oil and gas activities proves more difficult, cost reductions could be somewhat slower, represented by our medium-cost case. In both cases, construction costs for next-generation geothermal plants would be in the range of USD 3 000-7 000/kW by 2035. With additional reductions stemming from the learning-by-doing principle, the range of construction costs falls to USD 2 000-5 000/kW in 2050.

In absolute cost terms, for a 300-MW project at a depth of 3 km and temperature of 200°C, the total capital investment in 2035 would fall from over USD 4 billion for first-of-a-kind projects to USD 2 billion in the medium-cost case and USD 1 billion in the low-cost case. Even at the lower end of this range, drilling costs would represent around USD 600 million. By 2050, the total capital expenditure for a 300-MW next-generation geothermal project would be USD 1.2 billion in the medium-cost case and USD 600 million in the low-cost case.

Assumed average next-generation geothermal construction costs, 2025-2050



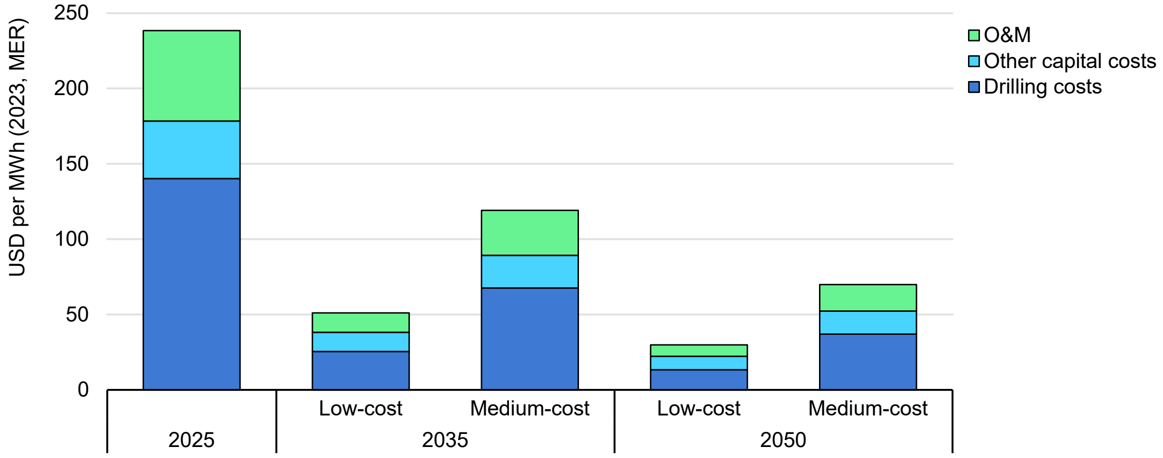
Notes: MER = market exchange rate. Costs shown are for projects with an average size of 300 MW; depth of 3 km; temperature of 200°C in suitable conditions.

The levelised cost of electricity (LCOE) is a common metric of power technology costs, as it aggregates all direct costs associated with a technology into a single value, representing the average cost of producing each unit of electricity over the technology's lifetime. It includes capital costs, operations and maintenance costs, fuel costs, carbon costs and decommissioning costs. The extent to which each of these factors affects the LCOE varies significantly between technologies and across countries.

For geothermal projects, which have no fuel or carbon costs (an advantage over fossil fuel-based power plants), construction and financing costs are the most consequential for LCOE. Furthermore, the absence of critical mineral requirements for geothermal developments also shields projects from associated potential market volatility. The LCOE is often used to evaluate the competitiveness of various power generation technologies, though it is not always a reliable metric for comparison (see box below on value-adjusted LCOE [VALCOE]).

The LCOE of first-of-a-kind next-generation geothermal projects is over USD 230 per megawatt-hour (MWh). However, with the construction cost reductions described, the LCOE of next-generation geothermal in the low-cost case would decline to about USD 50/MWh in 2035 and USD 30/MWh in 2050. In the medium-cost case, the LCOE declines to USD 120/MWh in 2035 and USD 70/MWh in 2050. In all cases, the average financing rate – or weighted average cost of capital (WACC) – is assumed to be 7% in real, pre-tax terms. Because geothermal developments are capital-intensive, the LCOE is sensitive to financing conditions and modes of operation (see box below on how capital costs and plant flexibility affect the LCOE).

Next-generation geothermal LCOE ranges in the Announced Pledges Scenario, 2025-2050



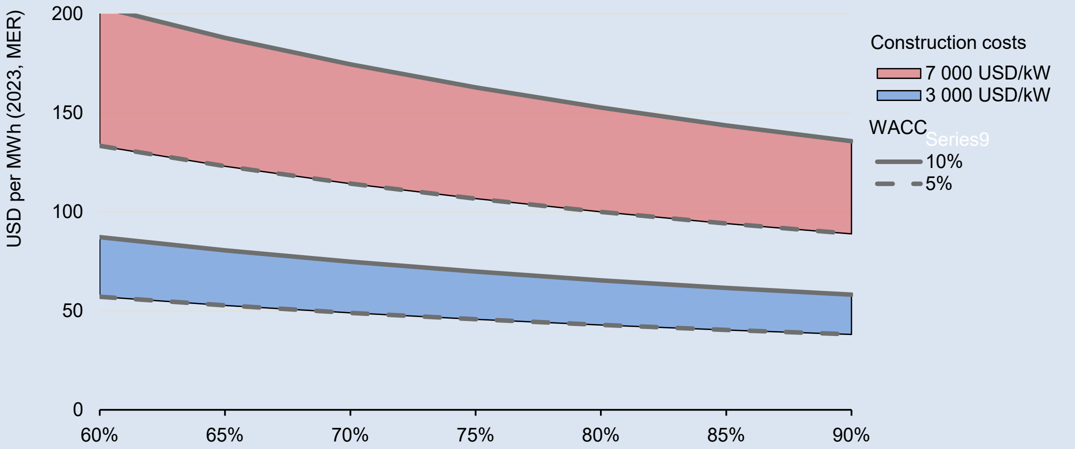
Notes: MER = market exchange rate. O&M = operations and maintenance. Costs shown are for projects operating at an 80% capacity factor and a WACC of 7%. "Drilling costs" and "other capital costs" include both construction and financing costs.

Geothermal LCOE sensitivity to construction costs, capacity factors and financing rates

In the average generation cost (the LCOE) of next-generation geothermal plants, upfront construction costs are the most important factor, followed by financing costs and how the plant is operated. The lowest LCOE is achieved when construction costs and financing rates are minimal and the capacity factor (i.e. the average output over a period relative to continuous operations at maximum capacity) is high. For example, the LCOE of next-generation geothermal in the low-cost case in 2035 could be as low as USD 40/MWh with affordable financing and a very high capacity factor of 90%. Conversely, the LCOE could be twice as high if the construction costs remain the same but financing rates are higher and operations are more flexible, with a capacity factor closer to 60%.

If construction costs are low enough, plants may be able to run more flexibly at lower capacity factors, but at higher capital costs they may need to run as baseload plants with a high capacity factor. The low-cost case for next-generation geothermal can unlock more flexible operations without raising the LCOE to an unattractive level: even with a 60% capacity factor and WACC of 10%, the LCOE remains well below USD 100/MWh. In contrast, the LCOE in the medium-cost case increases more significantly with higher financing costs, and more rapidly as the capacity factor declines.

Next-generation geothermal LCOE by construction cost, capacity factor and WACC



Notes: MER = market exchange rate. WACC = weighted average cost of capital. USD 7 000/kW is the medium-cost case in 2035; USD 3 000/kW is the low-cost case in 2035.

Next-generation geothermal competitiveness

When evaluating the competitiveness of different power generation technologies, it is important to assess both the technology costs and the value of the technology to the system. From a system perspective, this provides a more reliable indicator of overall electricity affordability. For investors, recognising the technology's full value in the market means profitability.

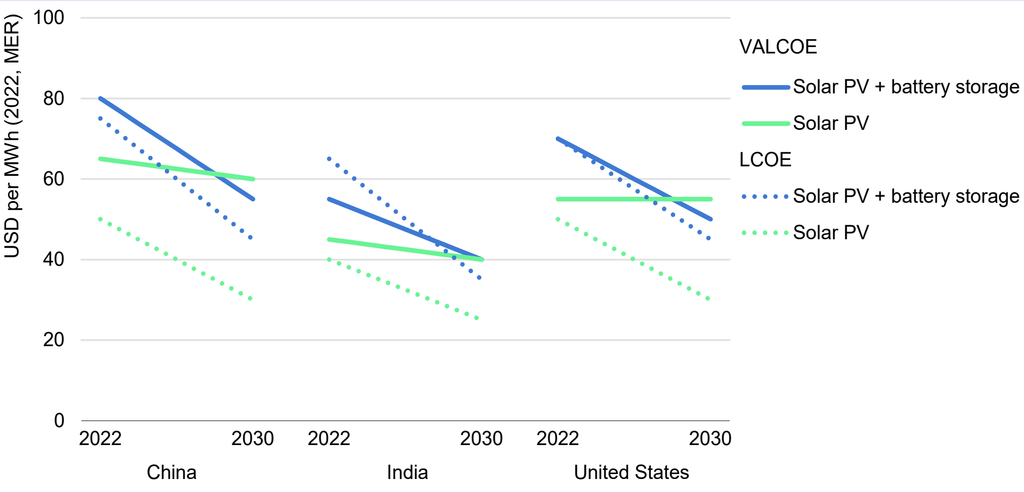
Dispatchable technologies with similar capacity factors have broadly comparable value to power systems, providing energy, capacity and flexibility services, so the LCOE alone can be a useful indicator of competitiveness among these technologies. However, because the LCOE takes no account of power system impacts and interactions, it is not a reliable indicator of competitiveness when comparing technologies with very different operational characteristics, notably in the case of dispatchable and variable renewables. The IEA has therefore developed the value-adjusted LCOE (VALCOE).

The value-adjusted LCOE is a more robust metric of competitiveness

To better account for the differences in value that technologies provide to the power system – an aspect not covered in the LCOE – the IEA developed and uses the VALCOE, a more comprehensive measure of competitiveness that combines the technology cost (LCOE) with the value of three system services (energy, flexibility and capacity), drawing on detailed hourly modelling of electricity demand and supply.

Each power system is unique, defined by many characteristics including demand patterns, the supply mix and the share of renewables. As solar PV and wind shares continue to rise, the value of energy provided by these sources tends to decrease in relation to the system average, and the value of flexibility tends to increase. Both trends underscore the importance of looking beyond the LCOE to determine competitiveness.

VALCOE and LCOE of solar PV and solar PV plus battery storage



Notes: MER = market exchange rate. LCOE = levelised cost of electricity. VALCOE = value-adjusted LCOE.

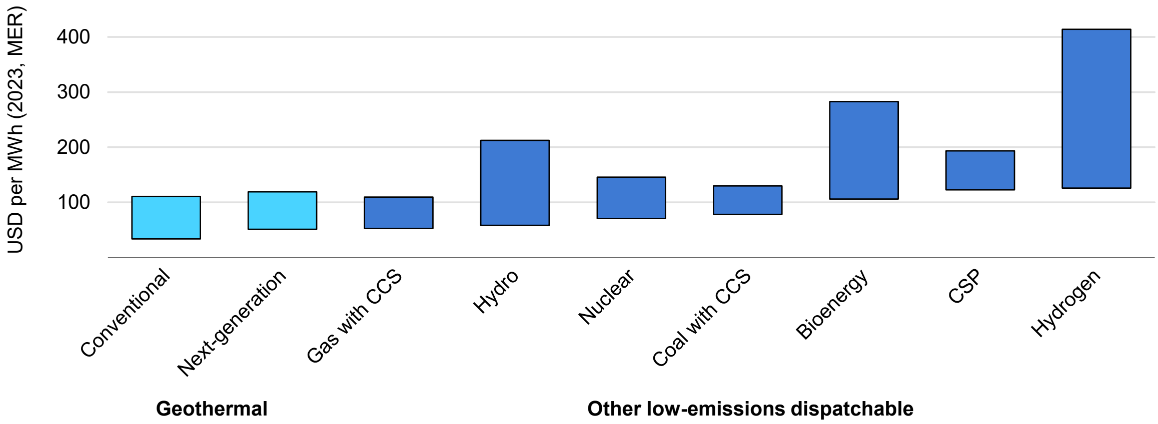
Note: Values for projection years are based on IEA modelling in the *World Energy Outlook 2023*, Announced Pledges Scenario

The VALCOE also evaluates the competitiveness of energy storage, either as a stand-alone option or paired with other sources. For example, based on the VALCOE, pairing solar PV with battery storage makes it much more cost-competitive with solar PV-only in China, India and the United States. This reflects the increasing importance of generating energy at the right time and providing flexibility and capacity services to the grid. However, assessing a system based on the LCOE alone would indicate that solar PV without storage is the lower-cost choice. Pairing solar PV and battery storage is already one of most competitive options, as installed costs for both have dropped 90% in the past decade.

Next-generation geothermal competitiveness with other clean dispatchable technologies

If significant construction cost reductions are realised for next-generation geothermal, it could be one of the most competitive clean dispatchable technologies. In the low-cost case, next-generation geothermal costs would be on a par with or lower than all other clean dispatchable technologies by 2035, including conventional geothermal, natural gas-fired with carbon capture, hydro, nuclear, coal with carbon capture, bioenergy, CSP and hydrogen. Each technology's cost range reflects regional differences in construction expenses and in resource and fuel costs, which apply to natural gas, coal, bioenergy and hydrogen.

LCOE of geothermal and other low-emissions dispatchable technologies in the Announced Pledges Scenario, 2035



Notes: MER = market exchange rate. CCS = carbon capture and storage. CSP = concentrating solar power. The next-generation geothermal cost range is for projects with an 80% capacity factor and a WACC of 7%. The capacity factors of the other technologies are assumed to be 80% for conventional geothermal; 60% for gas with CCS; 40% for hydro; 80% for nuclear; 70% for coal with CCS; 60% for bioenergy; 40% for CSP; and 50% for hydrogen.

In the medium-cost case, the LCOE of next-generation geothermal is above USD 100/MWh in 2035, which is significantly higher than the low end of costs for several other clean dispatchable options. This means that lower-cost options would include natural gas with carbon capture and hydropower, as resources are available and of good quality. Nuclear power could also be a more attractive option when projects are delivered on time and on budget.

Innovation could bring more clean dispatchable sources of electricity to the market in upcoming years, boosting competition. For example, small modular reactors (SMRs) are under development in many countries. With more than 80 designs being developed and a growing number of commitments to build new projects, the delivered cost of SMRs will be an important point of comparison for next-generation geothermal in the future, as both technologies could be available in most locations.

The cost of other clean dispatchable technologies, including low-emissions hydrogen and ammonia, could also drop considerably and help support electricity security during clean energy transitions. Given these cost uncertainties, a portfolio approach that includes a variety of low-emissions dispatchable technologies should be taken to ensure secure energy transitions.

Next-generation geothermal competitiveness with variable renewables

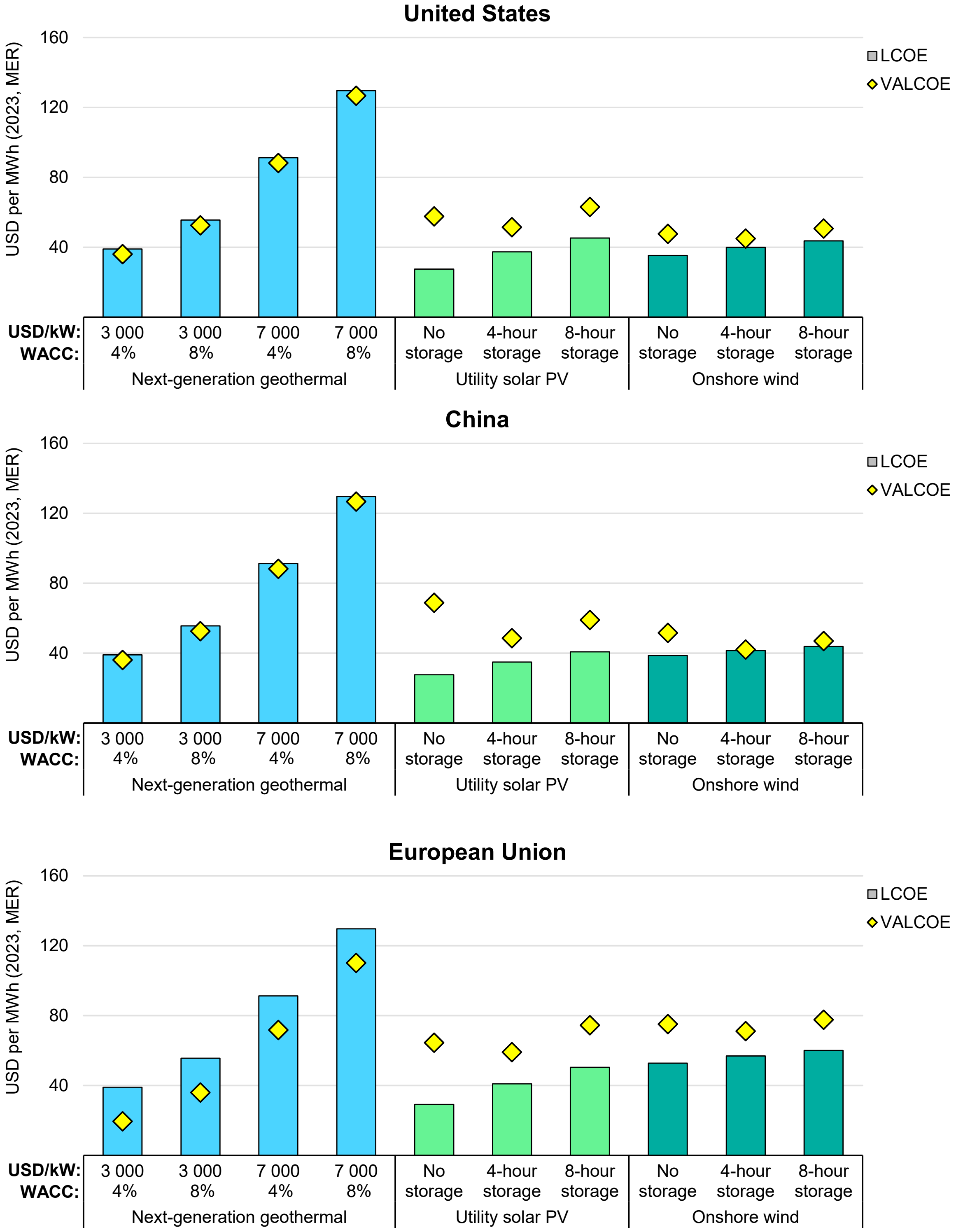
Although making next-generation geothermal plants competitive with solar PV and wind installations would create extensive market opportunities, achieving cost-competitiveness will be challenging, as the average utility-scale solar PV LCOE has plummeted 90% since 2010, onshore wind has dropped 70% and offshore wind has fallen 60%. As a result, solar PV and wind are the most affordable new sources of electricity in most markets today.

However, as round-the-clock availability and dispatchability are key attractions of next-generation geothermal generation but not of solar PV and wind, it is necessary to consider both the technology costs and value provided by each technology (captured in VALCOE calculations) to evaluate their relative competitiveness. Regional-level comparisons are most useful, as value depends on many system-specific factors, including the established power plant fleet; domestic resources; fuel prices; renewable-resource quality; and electricity demand patterns.

Next-generation geothermal can become competitive with solar PV and wind by 2035 in several major regions – including the United States, Europe, and China – if the low-cost case is realised, capacity factors are high, and financing costs are medium to low. Based on the VALCOE of next-generation geothermal – which is similar to its LCOE because it runs at a high capacity factor and has close to the system average contribution to energy, flexibility and capacity – it is more competitive than standalone solar PV and wind by 2035, as these technologies are of far lower value to systems because of the cannibalisation effect.[13] This is true even with a WACC as high as 8% in several regions, which is noteworthy since financing costs for next-generation geothermal projects are uncertain given their current stage of development.

[13] When the average market price (or capture price) received by a technology declines as its own share of electricity generation rises, lowering its system value.

Value-adjusted LCOE of next-generation geothermal and other low-emissions technologies in the Announced Pledges Scenario, 2035



Notes: MER = market exchange rate. WACC = weighted average cost of capital. LCOE = levelised cost of electricity. VALCOE = value-adjusted LCOE. The assumed capacity factor for geothermal is 80%. LCOE and VALCOE for solar PV and wind are from the World Energy Outlook 2024 APS. The WACC assumption for solar PV and wind are 4-5% in the United States, China and the European Union.

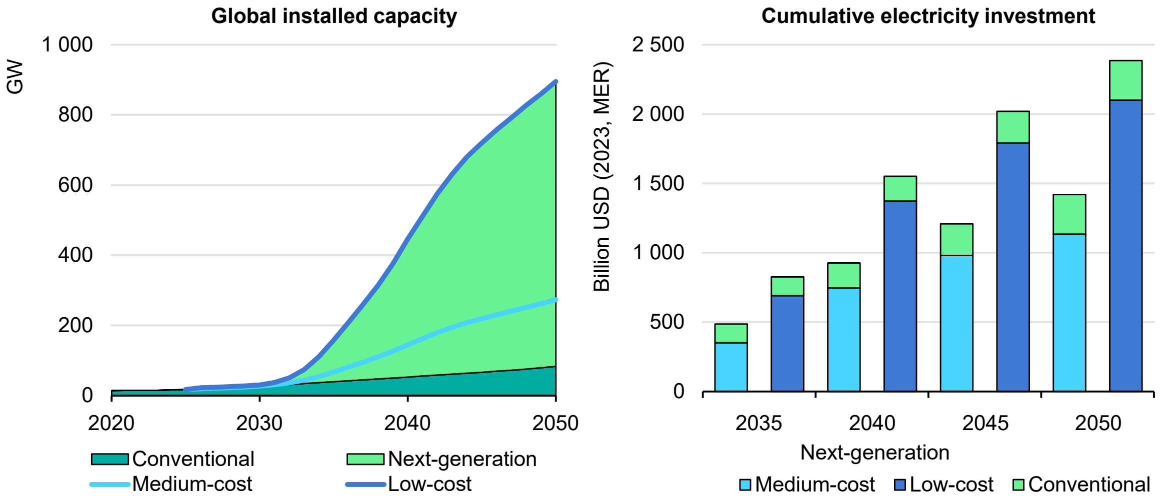
Next-generation geothermal is also competitive with solar PV and wind paired with battery storage, which explains why both its costs and system value increase when it becomes more dispatchable. Indeed, the VALCOE for next-generation geothermal is USD 40-55/MWh, and for solar PV paired with battery storage it is around USD 50-60/MWh in the United States and China, and up to USD 75/MWh in Europe. For onshore wind paired with storage, the VALCOE is around USD 45-50/MWh in the United States and China, and up to nearly USD 80/MWh in the European Union. If costs for next-generation geothermal continue to decline to 2050 within the low- and medium-cost ranges, it will be even more competitive with solar PV and wind because their values decline as their shares in the electricity mix increase.

Next-generation geothermal market potential

Global outlook for next-generation geothermal electricity

The market potential for next-generation geothermal depends strongly on how much costs can be reduced. In the low-cost case, we find that global market potential for next-generation geothermal could be 120 GW by 2035 and over 800 GW by 2050. This level of development – wherein next-generation geothermal would provide 8% of global electricity supply in 2050 – is also contingent on meeting environmental requirements and gaining social acceptance. This growth would be additional to conventional geothermal, which expands to around 80 GW by 2050 (see Chapter 1). Tapping all this market potential would require a cumulative investment of around USD 700 billion in next-generation geothermal by 2035, and over USD 2.1 trillion by 2050.

Global next-generation geothermal electricity market potential and investment in the Announced Pledges Scenario, 2020-2050



Note: MER = market exchange rate.

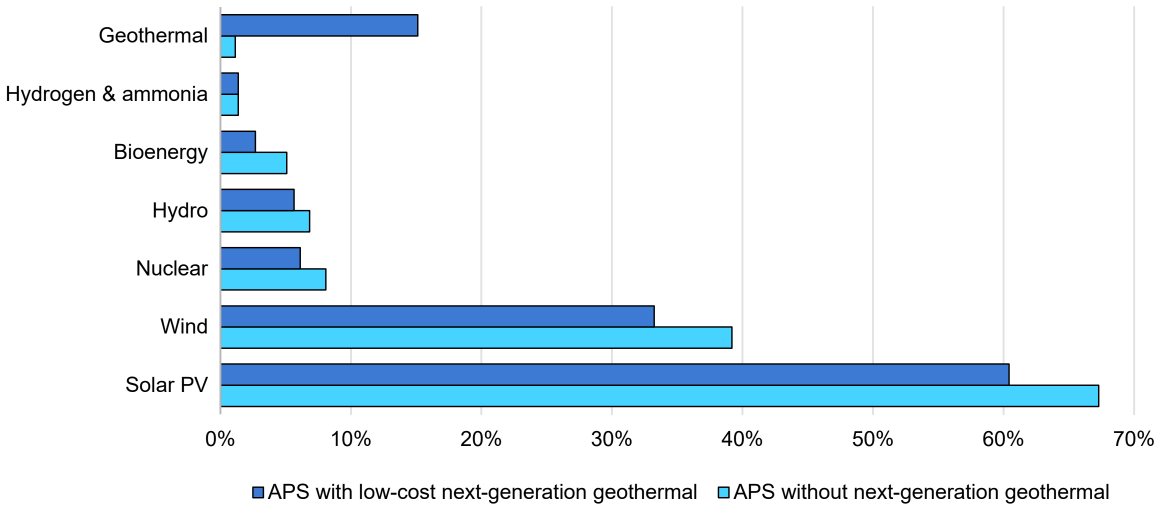
In the medium-cost case, global market potential for next-generation geothermal is nearly 30 GW by 2035 and 190 GW by 2050. While this is only one-quarter of the low-cost case, it is still over twice as much as conventional geothermal capacity in 2050. Because construction costs are higher in the medium-cost case, the cumulative investment spending in next-generation geothermal power capacity to 2035 is USD 350 billion and over USD 1 trillion to 2050 – still 50% of investment in the low-cost case.

Developing the full market potential of next-generation geothermal in the low-cost case would deliver up to 15% of total electricity generation growth to 2050 in the APS. This is in addition to the 1% met by conventional geothermal. The first installations of next-generation geothermal capacity would displace other low-emissions dispatchable options such as nuclear, hydro, bioenergy and CSP, as well as coal- and gas-fired carbon capture and storage (CCS) and hydrogen-fuelled turbines.

Bioenergy would be one of the first options to be displaced, as fuel costs can be high if biomass supplies have to be transported over land for any significant distance. CSP and nuclear power would also face competition, depending on their performance in upcoming years, and hydropower would be displaced somewhat as resource potential diminishes.

Solar PV and wind deliver the largest shares of total electricity generation growth and displace unabated fossil fuels to 2050 in the APS. This remains true even with the rapid development of next-generation geothermal in the low-cost case. This would also mean less battery storage deployment, as fewer solar PV and wind installations would be added to electricity systems.

Global share of total electricity generation growth by technology, 2023-2050



Note: Shares calculated as technology growth divided by increase in total generation, though sum can be over 100% as unabated fossil fuels declines significantly.

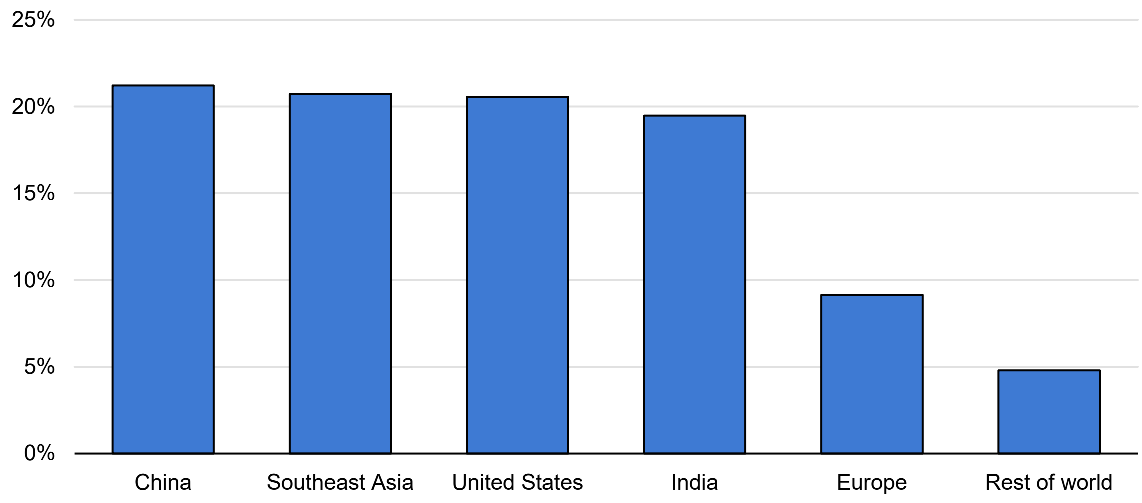
Regional outlook for next-generation geothermal electricity

If costs for next-generation geothermal decrease to the low- or even medium-cost level, it could play an important role as a low-emissions dispatchable option in the electricity mixes of several regions. This would be particularly valuable in areas that currently rely heavily on coal-fired power – including China, India and Southeast Asia – or aim to reduce their use of natural gas-fired power such as Europe and the United States. China, the United States and India have the greatest market potential for next-generation geothermal electricity in our analysis, together accounting for three-quarters of global potential in the low-cost case.

China has the largest market potential, with around 40% of global capacity in 2050. The high degree of electrification in China that is still heavily powered by coal today means that the country is in need of affordable low-emissions dispatchable electricity to meet the 2060 carbon neutrality goals of its 14th Five-Year Plan. Based on technology costs, the first dispatchable power source to be displaced would be hydro, followed by nuclear.

Over the next 25 years, China needs to deploy nearly 700 GW of low-emissions dispatchable power capacity to maintain energy security, and it has the capital required to do so. Nearly half of this capacity could be geothermal if low costs are achieved. Although a large amount of new solar PV and wind capacity would be displaced, in 2050 these installations would still be by far the main electricity sources keeping China on the path to carbon neutrality.

Share of total electricity generation growth from next-generation geothermal in selected regions in the Announced Pledges Scenario, 2050



The United States is the second-largest market for next-generation geothermal, with domestic high-quality resources and expertise in geothermal innovation, leveraged in part from its oil and gas industry. As energy transitions move forward in the United States, driven by state-level policies and technology support from the federal government, unlocking another dispatchable low-cost, low-emissions option with widespread resources across the country would open a large market. Additionally, demand from technology companies is growing, as they look to meet the growing needs of data centres with firm clean power. If costs are low enough, next-generation geothermal would displace bioenergy first, then compete with new nuclear and displace some wind, solar PV and batteries.

Meanwhile, India is the third-largest market for next-generation geothermal power capacity by 2050. The dispatchability of next-generation geothermal would pair well with the production profile of solar PV in India, which would otherwise reach 35% of total electricity generation by 2035 and 50% by 2050. Deploying next-generation geothermal technologies would help India meet growing electricity demand while avoiding the need for additional coal-fired power plants, and it may be a more affordable option that displaces some CSP, hydro and bioenergy. If next-generation geothermal expands quickly enough in India, it could also eliminate the need for some solar PV capacity and batteries, creating a more diverse clean energy mix.

In other markets such as Southeast Asia – where rising incomes and economic development are rapidly raising electricity demand – next-generation geothermal could be an affordable domestic option to reduce current coal-fired dependency while ensuring continued energy security. Deploying next-generation geothermal technologies would also reduce the need for imports that are subject to market volatility.

In Europe, where clean energy transitions are already in advanced stages, the need for additional low-emissions dispatchable options is growing in electricity systems that rely on large shares of solar PV and wind. In Japan, high-quality next-generation geothermal resources present the possibility of reducing fossil fuel imports, thereby enhancing energy independence.

Next-generation geothermal for heat

Today, heat for space and water heating and industrial processes is produced primarily through fossil fuel combustion. This makes heat production one of the largest contributors to global energy-related CO_2 emissions, accounting for nearly 40% of the total.

Achieving the world's climate targets will therefore require a significant reduction in heat-related emissions over the next 25 years. As mentioned in Chapter 1, conventional geothermal applications and the installation of ground-source heat pumps for heating and cooling are already helping meet these targets. However, next-generation geothermal technologies significantly extend the range of locations where geothermal energy could be tapped to supply heat, making them a potential option for the large-scale provision of low-emissions heat, alongside other alternatives such as electrification, bioenergy, fossil fuels with carbon capture, nuclear energy and low-emissions fuels.

While the technical potential of conventional geothermal projects is limited to areas with suitable geological conditions, next-generation geothermal projects could be deployed much more widely across the globe, even outside of regions with conventional geothermal resources. If there are sufficient drops in next-generation geothermal project upfront investment costs (which are determined mainly by the cost of well drilling), the direct use of geothermal energy to provide process heat to industrial plants or clusters could become a viable option, in addition to the more established provision of low-temperature heat to district heating networks.

The relatively high temperatures of up to 200°C that can be achieved by next-generation geothermal plants would also allow for the more widespread deployment of geothermal combined heat and power (CHP) plants (also referred to as co-generation). In addition, one emerging application could be centralised cooling, whereby geothermal heat is used to drive absorption chillers that produce cold water that is then circulated through district cooling networks.

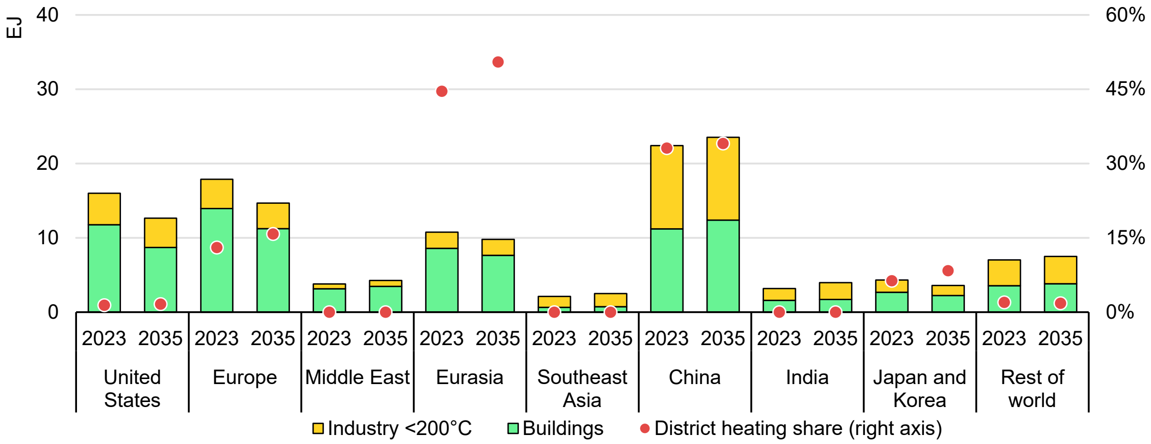
Space and water heating dominate demand for heat below 200°C

Around half of total global heat demand is for heat of less than 200°C. Two-thirds of the heat demand in this temperature range is for space and water heating in buildings, and the remaining one-third is for industrial processes, mainly in light industries but also for auxiliary processes in energy-intensive industries. As a result, demand for heat below 200°C is greatest in regions with below-average air temperatures and higher space heating requirements, such as the United States, Europe, Eurasia and China.

In China, high industrial heat demand is also important. In India and Africa, heat is used primarily in industry, and overall demand is much lower. Centralised heat production in district heating networks, which currently covers less than one-fifth of global demand for heat below 200°C, is concentrated mainly in Eurasia, China and Europe. In these regions, the relatively high concentration and density of areas with strong heating demand (e.g. cities), as well as political support in many cases, led to the more widespread establishment of heating networks.

In the APS, district heating coverage continues to expand, even as overall demand for space and hot water heating falls thanks to improvements in building envelopes. This helps reduce reliance on fossil fuels for heating – not only in regions with currently high shares of district heating, but also increasingly in those that have so far had comparably little investment in heating networks, such as Japan, Korea and North America.

Demand for heat below 200°C and district heating shares by region in the Announced Pledges Scenario, 2023 and 2035



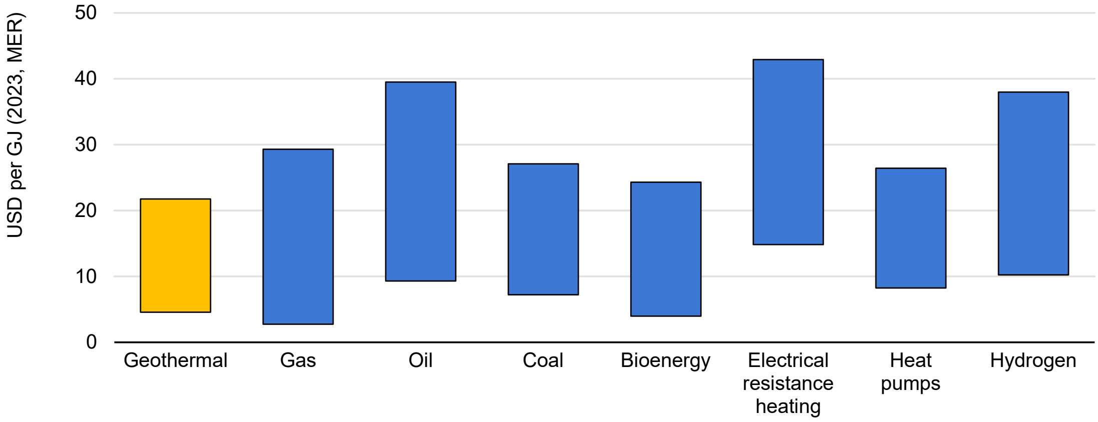
Next-generation geothermal systems could be deployed to provide both space and process heat. An important consideration is the volume of heat required, which needs to be large enough to justify the significant upfront investment required to drill the necessary geothermal wells. We therefore focus in this chapter on using next-generation geothermal technologies – particularly co-generation plants that generate both power and heat – to provide process heat directly to industrial consumers such as plants or industrial parks and for centralised heat production in district heating networks. The following sections examine both cases in more detail.

Falling costs could make next-generation geothermal an attractive source of low-temperature industrial heat

If construction costs decline significantly, next-generation geothermal could become a cost-competitive source of heat for large industrial plants and industrial parks. In a low-cost case in which upfront costs for a next-generation geothermal heat plant decline to around USD 1 150/kW$_{th}$ by 2035 thanks to a drop in drilling expenses, the levelised cost of heat falls to around USD 5/GJ. At this level, next-generation geothermal would be cost-competitive with fossil fuel-based and other low-emissions heating technologies.

The most important low-emissions alternatives would be electric heat pumps (particularly when electricity prices are low and waste heat is available to achieve a high coefficient of performance) and bioenergy heaters, which require locally available sustainable feedstocks such as forestry or agricultural residues. However, next-generation geothermal projects could also reduce the pressure of additional deployment for these low-emissions technologies – especially bioenergy, for which obtaining sustainable feedstocks can be challenging. Industrial bioenergy demand increases by 6 EJ or 50% in the APS between now and 2035.

Levelised cost of heat for direct heat use in industry in the APS, 2035



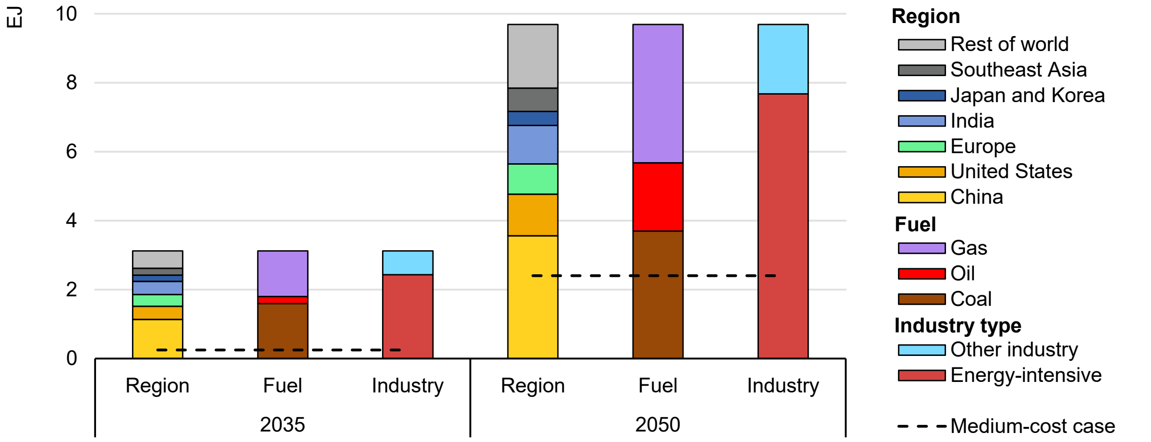
Notes: MER = market exchange rate. Fuel cost ranges are: natural gas, USD 2-20/MBtu; oil, USD 350-1 100/toe; coal, USD 25-125/Mtce; biomass, USD 2-20/MBtu; electricity, USD 50-150/MWh; and hydrogen, USD 1-4/kgH_2. The CO_2 price range is USD 0-160/tCO_2. The heat pump coefficient-of-performance range is 2-6. The levelised cost of heat of geothermal is calculated using cost data for electricity applications, with a conversion ratio of 2 kW_{th}/kW_e to translate costs from electrical to thermal terms. Assumptions include subsurface costs of USD 1 000-3 000/kW_{th} and heat plant costs of USD 150/kW_{th}.

Based on a cost-competitiveness analysis within the APS,[14] if next-generation geothermal develops as projected under the low-cost case, it could economically displace about 3 EJ of fossil fuel consumption for industrial heat globally by 2035 – about 10% of industrial demand for heat below 200°C. This shift would avoid approximately 230 Mt of CO_2 emissions, which is more than the annual emissions of Argentina. Assuming a further cost decrease to USD 3/GJ, the displaced volume could rise to almost 10 EJ by 2050, covering about 35% of industrial demand for heat below 200°C.

In a medium-cost scenario with next-generation geothermal levelised costs of heat of USD 22/GJ in 2035 and USD 12/GJ in 2050, market potential is much lower in both years, with heat pumps remaining a more cost-competitive low-emissions heat technology in many regions.

[14] This analysis was carried out for the Announced Pledges Scenario (APS) of *World Energy Outlook 2024* on a regional basis, considering regional fossil fuel end users and carbon prices.

Market potential for geothermal heat production in the low-cost case by region, substituted fuel and subsector in the Announced Pledges Scenario, 2035 and 2050



The large difference between the two cases indicates that geothermal deployment potential will also depend on its cost-competitiveness with other low-emissions technologies. In the low-cost case, the break-even point with industrial heat pumps is reached before 2035 in most regions, while in the medium-cost case the crossover occurs only after 2040 in most regions. Until then, the higher investment costs of next-generation geothermal would limit its competitiveness and widespread adoption. Nonetheless, next-generation geothermal applications could still be used in the short term in regions with high fossil fuel and electricity prices (e.g. Europe) or high industrial heat demand (e.g. India and China).

By 2050, further reductions in upfront investment costs, coupled with higher CO_2 prices, could make next-generation geothermal cost-competitive with both fossil fuel-based heating systems and industrial heat pumps. Thus, geothermal could conceivably be competitive by mid-century in regions where heat pumps could replace fossil fuel heaters in the short term. Again, potential markets for next-generation geothermal heat in 2050 are especially large in regions with high fossil fuel and electricity prices, or with considerable industrial heat demand.

Next-generation geothermal could become particularly competitive in industries requiring process heat of 100-200°C, such as paper and chemicals production, auxiliary processes in cement production and food processing. Compared with conventional geothermal systems, next-generation technologies can provide these temperatures in a wider range of locations, significantly expanding the potential market.

Given the technology's technical and economic constraints, 100-200°C appears to be ideal: for lower-temperature requirements, other options such as heat pumps may be more competitive, while for higher temperatures, fuel combustion or the direct use of electricity are likely to remain necessary, as next-generation geothermal systems will probably continue to be limited to maximum temperatures of around 200°C for technical and cost reasons.

While the market potential seems promising, the most important caveats to next-generation development are the investment costs and planning time required. For instance, subsurface costs for a next-generation geothermal plant providing 1 PJ of thermal energy per year are roughly USD 350 million (expected to fall to around USD 60 million by 2035 in the low-cost case) – similar to the average capital costs for a typical cement plant (USD 350 million) and significantly higher than for a paper mill (around USD 60 million).

Furthermore, the average planning time of 1-4 years before a geothermal plant can begin actual operations can affect the investment decisions of companies planning to recuperate their investments after 10-15 years. Public support for industrial clusters or hubs could mitigate the default risks of single companies or plants, aggregating demand from a group of plants. Industrial plants could of course also get geothermal heat from a district heating network.

Next-generation geothermal could become a competitive source of low-emissions heat for district heating

Next-generation geothermal CHP plants could provide large volumes of low-temperature heat to district heating networks, but upfront investment costs would need to drop significantly (to below USD 4 000/kW) for them to be cost-competitive with other low-emissions options.

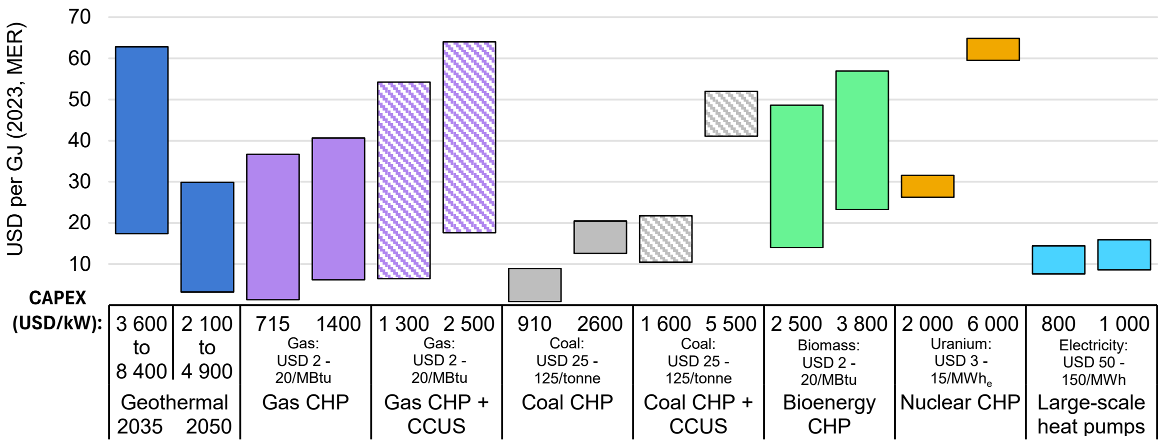
Globally, district heating is currently dominated by coal and natural gas-fired plants, many of them co-generating both heat and electricity. To meet their announced emission reduction pledges, countries and regions with relatively high shares of district heating in their overall heat supply (such as China and Russia, as well as northern and eastern Europe) need to significantly increase their use of low-emissions technologies to produce heat for district heating systems.

Next-generation geothermal co-generation could be a promising (and potentially widely available) option. Other candidate technologies include coal- or natural gas-fired co-generation with carbon capture; bioenergy co-generation; nuclear co-generation; and large-scale heat pumps that use low-emissions electricity. Compared with producing heat only, co-generation can be attractive because it enables the simultaneous generation of dispatchable electricity, a higher-value product. Given their near-zero marginal cost, geothermal CHP plants would tend to operate at high annual load factors even at times of low heat demand, generating a significant share of their revenue from electricity sales.

The levelised cost of heat produced by a heat or CHP plant is determined mainly by plant construction costs and fuel input prices, as well as revenue from the sale of electricity, which can be credited against the cost of heat. Globally, based on the long-term trajectory for coal and natural gas prices in the APS, the cost of heat supplied by natural gas-fired CHP plants equipped with carbon capture would range from less than USD 10/GJ to USD 30/GJ, while that of heat supplied from coal-fired CHP plants with carbon capture would be between USD 10/GJ and USD 45/GJ. Costs would be the lowest in regions with low fossil fuel prices and low plant construction costs.

Bioenergy CHP plants could produce heat for as little as USD 15/GJ if cheap, sustainable feedstocks such as forestry or agricultural residues are available locally. Meanwhile, for nuclear-based CHP plants, the levelised cost of heat is highly dependent on the plant's capital costs, ranging from about USD 45/GJ for plants with construction costs of USD 6 000/kW to below USD 10/GJ for plants with construction costs of USD 2 000/kW. Large-scale heat pumps could produce heat for as little as USD 7-15/GJ even at comparably high average electricity prices.

Levelised cost of heat supplied to district heating networks by source in the Announced Pledges Scenario, 2035 and 2050



Notes: CAPEX = capital expenditures. CHP = combined heat and power. CCUS = carbon capture, utilisation and storage. The levelised cost is the average net present value of the cost of producing heat for a plant over its operating lifetime. All plants are assumed to have annual utilisation of 80%. Geothermal co-generation plants are assumed to have a heat-to-power ratio of 1. An average selling price of USD 60/MWh (in 2023 US dollars) for electricity produced is credited against the cost of heat. A uniform weighted average cost of capital of 7% is applied to all investments. The cost range for natural gas co-generation corresponds to gas prices of USD 2-20/MBtu and CO_2 prices of USD 0-160/tCO_2; that for coal co-generation to coal prices of USD 25-125/tonne and CO_2 prices of USD 0-160/tCO_2; and that for bioenergy co-generation to feedstock costs of USD 2-20/MBtu. The assumed CCUS capture rate is 95%. Large-scale heat pumps have a coefficient of performance ranging from 3.8 to 4.1, and heat production costs correspond to electricity input prices of USD 50-150/MWh.

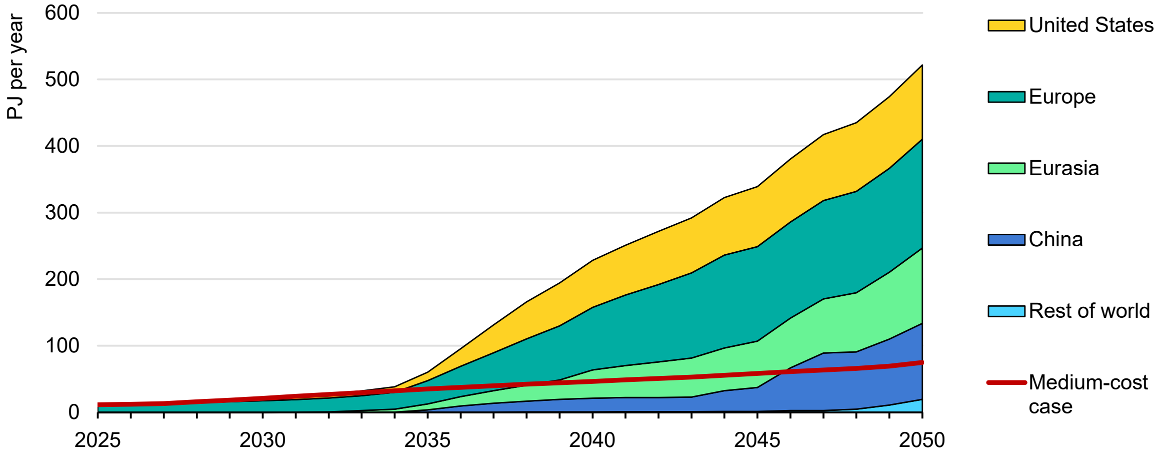
While the cost of heat produced by CHP plants using fossil fuels or biomass depends largely on fuel prices (with price spikes such as those of the 2022 energy crisis resulting in significant cost increases), the cost of heat produced by geothermal CHP plants is determined mainly by upfront investment costs – particularly for well drilling.

For geothermal co-generation to be competitive with fossil fuels in conjunction with CCUS, or with biomass or electric heat pumps for district heating, upfront investment costs would generally need to drop to below USD 4 000/kW. At this cost point, geothermal CHP plants would produce heat for around USD 20/GJ, falling into the cost range of fossil fuel-fired CHP plants with CCUS and nuclear co-generation facilities. At below USD 3 000/kW, next-generation geothermal CHP plants could be cost-competitive even with large-scale heat pumps, which promise to be among the lowest-cost providers of low-emissions heat in district heating networks in the medium term.

Next-generation geothermal could capture 20% of the growth for district heating between 2035 and 2050

How much of the centralised heat market next-generation geothermal technologies could capture depends mainly on the speed and magnitude of the anticipated drop in investment costs, and on the cost evolution of alternative options. More widespread adoption is likely only if costs fall below the USD 4 000/kW threshold.

Market potential for geothermal co-generation in district heating in the low-cost case under the Announced Pledges Scenario by region, 2025-2050



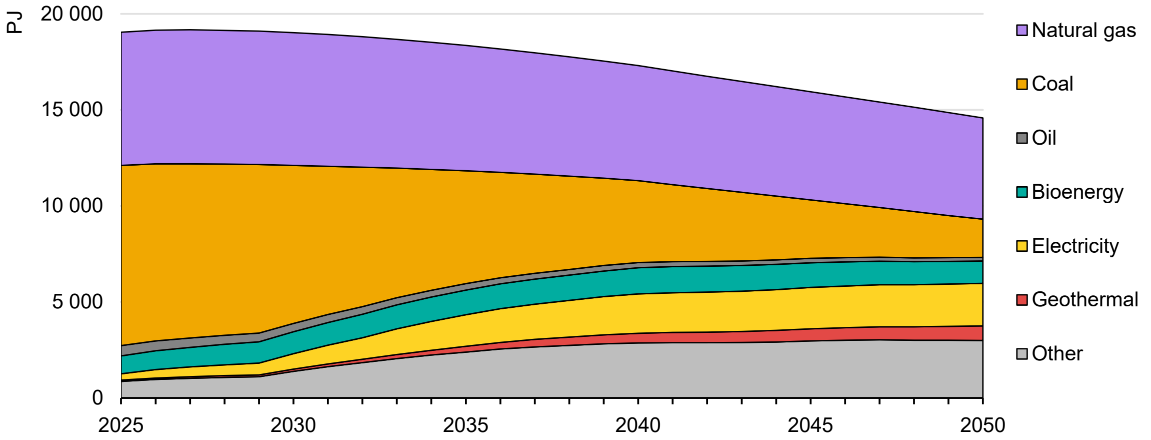
Note: This figure displays cumulative annual geothermal co-generation heat production capacity additions in district heating networks over 2025-2050 in the APS for the low-cost case.

In the APS, heat demand from district heating networks peaks and then falls over the outlook period owing to improvements in the energy efficiency of the building stock. At the same time, however, the progressive retirement of older coal- and natural gas-fired heat and CHP plants reaching the end of their operational lifespans (or subject to phaseout policies) creates significant demand for new replacement capacity.

In the low-cost case, global average investment costs for next-generation geothermal CHP plants fall to just over USD 3 500/kW by 2035 and nearly USD 2 000/kW by 2050, making them cost-competitive enough to displace new natural gas and bioenergy CHP plants, especially in Europe, although large-scale heat pumps remain a viable alternative, producing heat at a similar cost. Other large markets for advanced geothermal co-generation are the United States, Eurasia and China.

Consequently, the share of geothermal co-generation in global annual additions of new centralised heat production capacity rises to nearly 5% by 2035 and to 20% between 2040 and 2050. Cumulative geothermal CHP capacity additions grow to 60 PJ of heat production capacity per year until 2035 and to over 500 PJ per year until 2050. Assuming an average heat-to-power ratio of 1 and an average capacity factor of 80%, this translates into over 2 GW of power-generating capacity until 2035 and around 20 GW by 2050. As a result, the share of geothermal in the total global district heating supply rises to nearly 5% by 2050. In some regions, the share is even higher: in the United States, it rises to 40% and in Europe to nearly 10% by 2050.

Global district heating supply by source in the low-cost case under the Announced Pledges Scenario, 2025-2050



Note: "Other" includes nuclear co-generation, waste-to-energy, solar thermal and waste heat from industry.

In the medium-cost case, investment costs for next-generation geothermal CHP plants decline less rapidly, falling to around USD 8 500/kW by 2035 and just under USD 5 000/kW in 2050. In this case, the technology stays too expensive to be widely adopted to supply district heating networks and growth to 2050 remains slow. This demonstrates the necessity of achieving deep upfront investment cost reductions if next-generation geothermal is to make a significant contribution to the world's district heating supply.

It should be emphasised that the market potential described in this section assumes no early retirement of existing fossil fuelled-CHP plants in favour of next-generation geothermal. It also assumes no expansion of centralised heat production or heat networks beyond the APS level. Clearly, a faster retirement of the existing fossil-fuelled capacity and a more widespread adoption of district heating and cooling, as well as centralised heat production for industry, could substantially increase the market potential for next-generation geothermal co-generation. A significant drop in upfront investment costs (strong enough to allow for extensive low-cost heat production from next-generation geothermal sources) could increase the general attractiveness of centralised heating (and cooling) relative to decentralised options. This could be especially beneficial for regions that do not currently rely on these systems in a significant way, allowing for cost-effective establishment of heating and cooling networks in areas where demand is sufficiently concentrated (e.g. urban centres and industrial parks).

Countries with only small shares of district heating today include Japan, the United States and the United Kingdom. Other regions suitable for additional growth in centralised heat production are emerging markets and developing economies with large amounts of new construction, where heating and cooling networks could be integrated into new infrastructure from its inception. Centralised cooling could be of particular interest in densely populated regions with hot climates, such as India, parts of the Middle East and Southeast Asia.

Geothermal energy storage

Energy storage and flexibility are becoming increasingly essential components of resilient energy systems, particularly as the integration of variable renewable energy sources becomes more important. Given the effect of flexibly operations on the average cost of next-generation geothermal electricity generation, it is important to explore alternative solutions.

Geothermal storage technologies offer ways to use underground rock for energy storage, even in locations that are not necessarily suitable for next-generation geothermal energy exploitation. What we define as geothermal energy storage in this analysis encompasses a range of subsurface storage technologies. Building on geothermal-related technologies, they could provide both short-term and seasonal storage solutions, enhancing the overall effectiveness of energy management.

What is geothermal energy storage and how does it work?

Underground rock formations can store energy in multiple ways. While chemical energy storage (e.g. underground methane storage) might be the most widespread method, energy can also be stored as potential mechanical energy (e.g. through compressed air storage) or as thermal energy for future use. This section focuses on two different subfamilies of subsurface energy storage technologies: underground thermal energy storage and underground mechanical energy storage, both of which leverage geothermal industry developments.

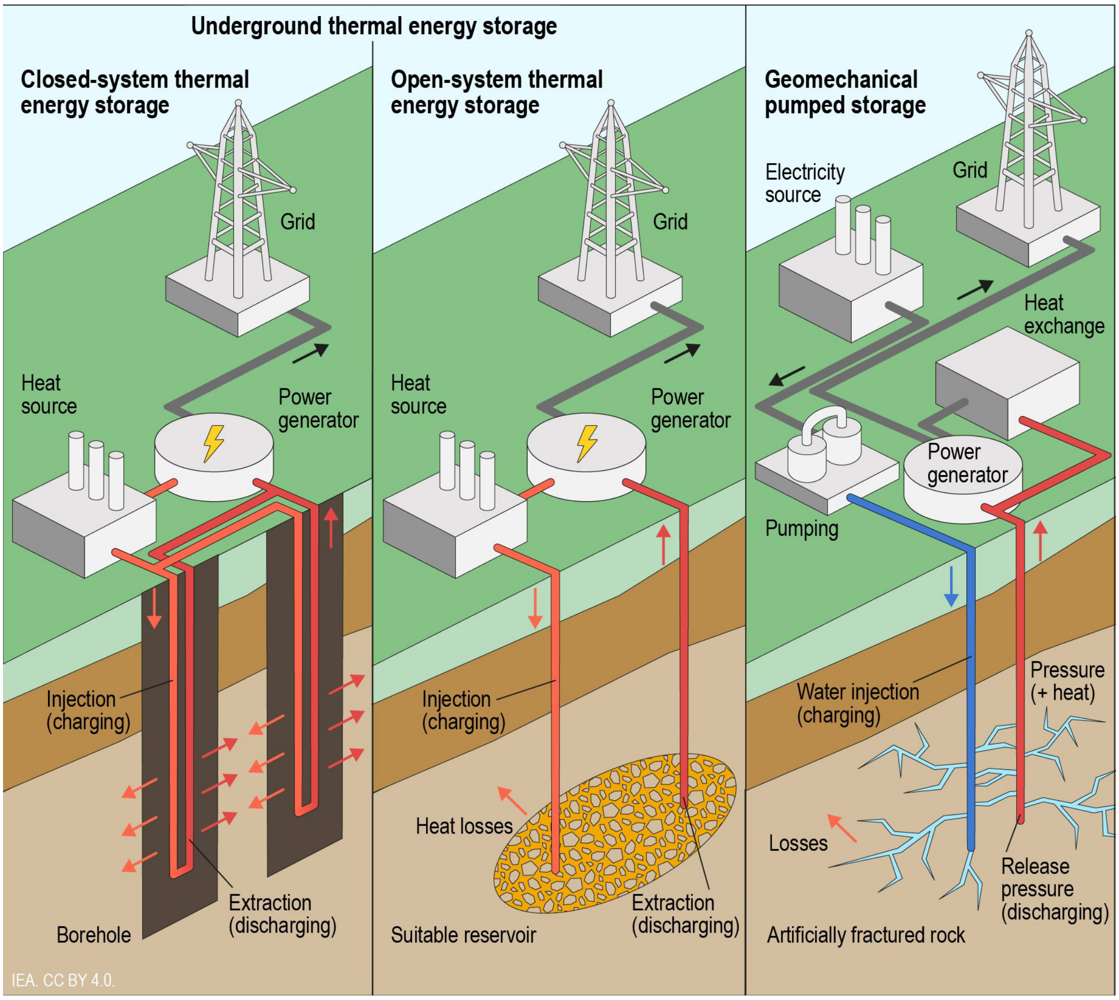
Underground thermal energy storage consists of storing heat from a heat source; storing electricity in the form of power-to-heat; or storing cold. Underground thermal energy storage can be used directly for district heating applications, but it can also be used to store electricity for long periods, a technique also known as geothermal battery energy storage or Carnot battery energy storage.

Underground thermal energy storage regroups many types of subsurface storage: closed systems such as borehole thermal energy storage, wherein a field of boreholes is used to store heat by conduction roughly 250 m below the surface; and open systems such as aquifer thermal energy storage (ATES) in shallow aquifers (less than 30°C, less than 400 m underground), high-temperature ATES in deeper aquifers and reservoirs (above 90°C, deeper than 1 000 m), and mine thermal energy storage in existing water-filled mine shafts and drifts.

Reservoirs can be in saline aquifers with water unfit for drinking or in depleted oil wells, where heat can be stored in the rock formation. Later, the stored heat can be retrieved for electricity generation or for direct heating, as is the case for district heating applications currently widespread in the Netherlands. Demonstration of underground thermal energy storage is currently ongoing in the PUSH-IT project, with demonstrations of aquifer thermal storage in Delft (NL) and Berlin (DE), borehole thermal storage in Darmstadt (DE) and Litoměřice (CZ), and mine thermal storage in Bochum (DE) and Cornwall (UK). Underground thermal energy storage is interesting because of its large storage volume potential and relatively small above-ground space requirements.

Using excess electricity to pump water into underground reservoirs created by hydraulic fracturing, mechanical underground energy storage (or geomechanical pumped storage) is a more innovative form of subsurface energy storage based on recent improvements to next-generation geothermal technologies. This process stores energy within the reservoir as elastic potential energy until it needs to be recovered. When demand arises, the water is released to drive turbines to generate electricity. This method can be integrated into or combined with geothermal plants, leveraging both the heat from surrounding rock formations and stored potential energy from underground pressure, positioning it as a valuable addition to geothermal energy technologies.

Overview of geothermal energy storage



Sources: Adapted from IEA-ES (2024), Technology: Sensible Heat Water Storage; Zhu, G. et al. (2024), Geological Thermal Energy Storage (GeoTES) Charged with Solar Thermal Technology Using Depleted Oil/Gas Reservoirs and Carnot-Battery Technique Using Shallow Reservoirs; and Sage Geosystems (2024), Geothermal Energy Storage Solutions.

What are the technical characteristics of these forms of energy storage?

Aside from the techniques already commercialised for relatively shallow depths, deeper underground thermal energy storage technologies (especially geomechanical pumped energy storage) hold promise, but their potential, efficiency, costs and environmental impact are uncertain, as these factors can vary significantly from project to project.

Underground thermal energy storage

Efficiency depends on reservoir properties such as porosity, permeability and the presence of impermeable sealing layers to reduce heat loss, with estimates ranging widely from 30% to over 90%. Reservoir depth is critical, as deeper wells mean higher drilling and pumping costs. A 1 500-m-deep storage facility would have capital costs almost 50% higher than a 500-m facility and would need almost five times more electricity for pumping.

However, thermal losses at 1 500 m can be reduced more than for a shallower reservoir, so a proper sensitivity analysis is required for better quantification. Depleted oil wells are preferred sites, but other geological formations may also be suitable.

Storage duration varies across projects and pilots: for example, a Californian project aims to store solar heat generated at 200°C for up to 1 000 hours. In large aquifers, groundwater structures are very cost-effective storage systems and have considerable capacity (seasonal durations are feasible), although many test drillings are required to assess the quality of the reservoir.

Costs remain uncertain and have yet to be proven on a large scale, though leveraging existing oil infrastructure and knowledge could make it possible to reduce expenses. Although uncertainties remain (and they are highly dependent on the assumptions used), initial estimates show that capital costs would have to drop 30-50% to be competitive with the average capital cost for pumped hydro storage (acknowledging that capital costs vary significantly across projects).

Mechanical underground energy storage

US pilot projects in Texas demonstrate round-trip efficiencies of 70-75% and storage durations of up to 10 hours, comparable to the storage capacity of long-duration batteries (typically around 8 hours) and small-scale pumped hydro storage. Like underground thermal energy storage, mechanical underground energy storage systems can utilise abandoned oil wells, with water injected and heated by underground geothermal activity to generate electricity and/or heat.

However, costs remain uncertain and might depend heavily on drilling and pumping expenses. Considerable cost reductions can be accomplished if significant learning from oil and gas activities can be transferred (see Chapter 3).

Potential risks such as induced seismicity, groundwater contamination, water overuse and habitat impacts require further investigation. Careful management and continued research are needed to develop these technologies and minimise risks to ecosystems and public health.

Flexibility in power systems

Can geothermal storage provide seasonal flexibility, and what are the potential competitors?

In absolute terms, power sector flexibility needs[15] increase on all timescales, in all scenarios and in all regions towards 2035 and 2050. Several factors drive this rise, including high wind and solar PV shares that tie the power sector to weather system variations; increasing electricity demand; and changes in electricity demand patterns.

Both the type and growth rate of flexibility requirements vary widely by region. In some regions with a significant surge in solar PV installations, the need for short-term flexibility increases to accommodate daily patterns. In other regions, parameters that change depending on the season (such as wind and a combination of temperature fluctuations and increased electrification) boost the need for seasonal flexibility.

Solutions to meet rising flexibility needs vary across regions. The figure below presents a range of technologies and illustrates the timescales in which they usually help meet flexibility needs. Not all technologies are accessible everywhere. In many places, strong grid integration within and between regions is necessary to optimise the use of available flexibility sources and to balance supply and demand over wider geographical areas. Price is also significant parameter for the diversity of flexibility contributors across different locations.

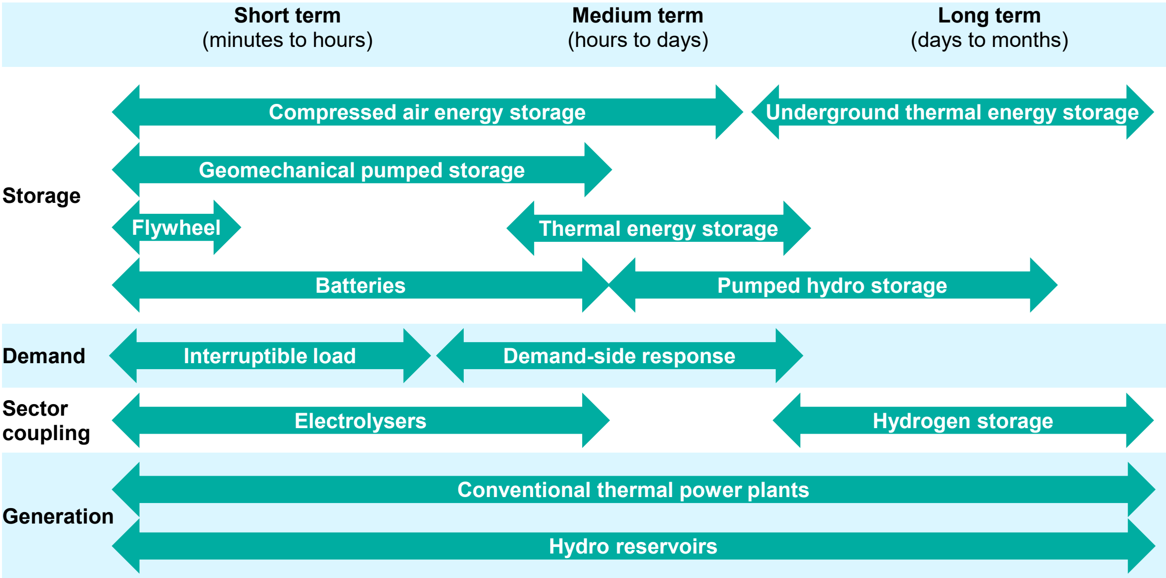
Batteries and demand-side response systems are projected to be the main solutions to provide short-term flexibility, but they are not well adapted to meet rising seasonal flexibility needs because of their limited capacity to store or shift electricity demand over durations of more than four to eight hours. In the APS, large hydro reservoirs, pumped hydro storage, thermal power generation and strategic curtailment are set to deliver the most seasonal flexibility.

Considering the efficiency and price of batteries and demand-side response systems to deliver short-term flexibility (and the few options for long-duration storage), geothermal battery energy storage appears to be a potentially credible solution for seasonal flexibility because it offers large, long-lasting reservoir capacity. A positive side effect of large energy storage systems is their dampening effect on grid load, which can reduce overall grid costs if appropriately located.

[15] Flexibility is defined as the ability of a power system to manage the variability of demand and supply, from ensuring the instantaneous stability of the grid to balancing demand and supply in each hour in all seasons.

Other yet-unproven technologies such as surface-based thermal storage and SMRs could also be possible flexibility solutions, if they prove to be technically feasible and competitive.

Key flexibility contributors by source and timescale



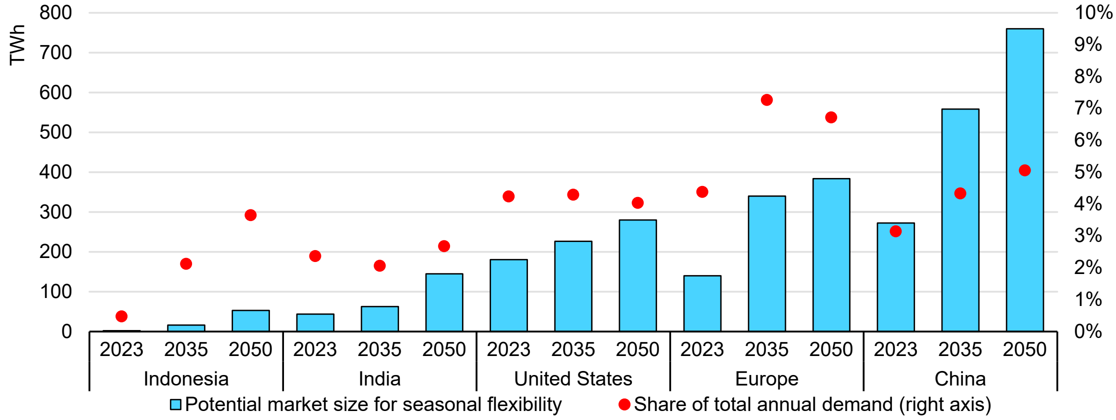
What is the market for seasonal flexibility and what are the opportunities for geothermal energy storage?

In the APS, seasonal flexibility needs increase by several hundred TWh in India, the United States, Europe and China from 2023 to 2050. The figure below shows the potential market size for seasonal flexibility contributors in the APS, based on seasonal flexibility needs divided by two. Potential market size can be interpreted as the theoretical upper boundary of the size of reservoir required to balance out all seasonal fluctuations in weekly average residual electricity demand,[16] assuming there are no losses, no limitations on charging and discharging capacity, and all flexibility is provided by a single large reservoir.

As mentioned above, no single storage technology is projected to provide all seasonal flexibility, so multiple actors can tap into this market. In Indonesia, Europe and China, flexibility needs expand more strongly than annual demand, emphasising the growing need for long-term flexibility contributors.

[16] Total electricity demand minus wind and solar PV generation.

Potential market size for seasonal flexibility in the Announced Pledges Scenario, 2023-2035



IEA. CC BY 4.0.

Notes: The potential market size for seasonal flexibility is based on seasonal flexibility needs divided by two. This number can be interpreted as the amount of storage capacity needed to balance out all fluctuations in weekly average residual electricity demand.

Seasonal flexibility needs are addressed differently depending on the region, as particular solutions may not be available in some locations. For instance, access to large hydro resources is limited in certain regions due to constrained or fully utilised potential. Additionally, climate change is projected to affect inflow availability, introducing uncertainty around the long-term reliability of this resource.

Fossil fuel power technologies are also under pressure for climatic reasons, and they face high carbon taxes or increasing costs due to CCS installation. Meanwhile, the effectiveness of electrolysers paired with hydrogen-based electricity generation depends heavily on access to affordable low-emissions hydrogen and on reasonable hydrogen storage prices, as this system suffers from relatively low round-trip efficiency compared with other technologies such as pumped-storage hydropower.

Underground thermal energy storage, as exemplified by the abovementioned pilot project in California, can possibly offer an alternative to existing technologies in some energy systems constrained by limitations, while also enhancing the variability and resiliency of seasonal flexibility sources. Plus, underground thermal energy storage producing heat can offer similar flexibility to the energy system, as it can reduce power-to-heat demand.

However, this can only happen if underground thermal energy storage proves its proficiency in multiple parameters. For instance, in terms of geographic potential in regions without hydro resources and access to clean, affordable energy sources for charging, underground thermal energy storage shows a round-trip efficiency competitive with that of electricity generation from hydrogen, and it is essentially cost-competitive with fossil fuel thermal power plants with CCS.

Importantly, the technology must also prove not to pose an environmental risk. If all requirements are successfully met, not only can underground thermal energy storage offer energy systems flexibility, but it does not rely on rare or critical minerals and requires relatively little surface space. As for geothermal storage itself, other unproven new technologies could also be possible flexibility contributors.

Some new and not technically mature technologies such as surface-based thermal storage and next-generation SMRs also appear to be potential competitors. However, as surface-based thermal storage is not very different from geothermal storage, it could be subject to similar challenges such as low round-trip efficiency. While space requirements for surface-based thermal storage systems could limit reservoir size and thereby reduce storage duration significantly (relative to underground thermal energy storage), this technology can nevertheless be used in most locations. Meanwhile, next-generation SMRs are very different from storage technologies, as they act as conventional power plants without needing access to inexpensive energy to charge.

Geothermal brine and the extraction of critical materials

For geothermal energy production, hot mineral-rich brine that has been circulating deep underground through hot rock formations must be pumped to the surface. In addition to its use in energy production, this brine offers the potential to extract valuable coproduct minerals such as lithium (in Europe and the United States), silica (in New Zealand), helium (in China), zinc, manganese and other critical materials.

Integrating geothermal energy production with the harvesting of critical minerals can enhance the economic viability of projects, as both enterprises are subject to high upfront costs and significant early-stage risks; reliance on geological and engineering expertise; some of the same permits; and complex project management skills. Ultimately, integrating projects would raise returns on investments by diversifying revenue streams, particularly when paired with long-term offtake agreements.

Lithium production

Lithium is in demand primarily for electric vehicles (EVs) and stationary storage. These uses account for about 55% of its consumption today, with the APS projecting 90% by 2035. As a critical cathode material in lithium-ion batteries, lithium demand surges from the current 165 kt/year to 912 kt/year by 2035 in this scenario.

The key lithium compounds for battery production are lithium carbonate and lithium hydroxide. Lithium carbonate is typically used in iron phosphate batteries, while lithium hydroxide is used in batteries with high energy densities (e.g. nickel-rich chemistries). Producing lithium hydroxide is typically faster and requires lower temperatures than lithium carbonate.

Lithium is sourced primarily from hard rock ores and brines.

Comparison of lithium extraction methods

	Hard rock ores	Brines	
Types	Pegmatite and other granite	Salar/salt ponds, geothermal and oilfield brines	
Global resources	20-30%	60-65%	
Production	64%	35% (out of which DLE is 10%)	
Grade (ppm)	High (>4 000)	Low (0-1 500)	
Technologies	Mining	Evaporation (only salar/salt ponds)	Direct lithium extraction
Key project countries	Australia, China	Chile, Argentina, Bolivia, China	Argentina, US, Germany, France
Lithium to market	Weeks to months	Months to years	Hours to days
Lithium recovery rate	60-80%	40-60%	80-95%
Water consumption	High 150 m^3/t	High (water loss due to evaporation) 250-450 m^3/t	Low-medium 50 m^3/t
Carbon emissions	High 15 t CO_2 per t LCE	Medium 5 t CO_2 per t LCE	Low 0 t CO_2 per t LCE
Land requirement	Medium 300 m^2	High 3 000 m^2	Low 0-6 m^2
Energy requirement	High 684 GJ/t Li	Low 41 GJ/t Li	Medium 145 GJ/t Li

Notes: DLE = direct lithium extraction. ppm = parts per million. Energy requirements are for mining lithium and refining it into lithium carbonates. LCE = lithium carbonate. Li = lithium content.

Sources: Based on International Lithium Association (2024), Direct Lithium Extraction (DLE); Vulcan Energy (2024), Corporate Presentations; IDTechEx (2024), Direct Lithium Extraction 2025-2035.

Potential for geothermal lithium production

Lithium production is concentrated in just a few countries, which has contributed to short- and medium-term demand-supply mismatches. Lengthy lead times for new lithium projects and public concerns over the environmental impact of traditional extraction methods exacerbate these gaps. In response, several countries have begun tapping into their own domestic sources, including geothermal brines, to enhance energy security and reduce supply chain vulnerabilities.

Assessing the viability of geothermal brines for lithium extraction involves evaluating lithium concentration, temperature and flow rate, water chemistry and sustainability aspects. Lithium concentrations above 150 ppm and geothermal brine temperatures of around 150°C are generally preferred, as they enhance lithium solubility, though lower concentrations can be viable with advanced extraction methods. Low levels of interfering ions such as magnesium and calcium simplify extraction, and systems that reinject brine help maintain the resource balance and reduce environmental impacts.

Detailed geothermal lithium extraction assessments have been led mainly by public bodies in the United States and Europe, highlighting the key role of governments in enabling and derisking these projects. In Europe, studies indicate that six geothermal areas across Italy, Germany, France, and the United Kingdom have high lithium concentrations in their geothermal brines (125-480 ppm). Among them, the Upper Rhine Valley between France and Germany shows a lithium production potential of 4-6 kt/year by 2030. In the United States, the Salton Sea Geothermal Field, with active geothermal power plants, has lithium concentrations of 100-400 ppm and an estimated capacity of 24 kt/year. These areas are currently hubs for multiple integrated geothermal-lithium projects.

Direct lithium extraction methods and integrated projects

Direct lithium extraction (DLE) is an innovative technology that unlocks vast unconventional resources by extracting lithium from geothermal and oilfield brines with lithium concentrations that are typically too low for traditional evaporation methods to process economically. Major companies, including those in oil and gas, are investing in DLE owing to its similarities to upstream extraction and refining processes.

To advance DLE technology and geothermal lithium extraction, the US Department of Energy has committed over USD 15 million to research and development supporting innovation in this field. Similarly, the European Union and several European countries have collectively funded geothermal lithium research and pilot projects, including EuGeLi, UnLiminted, LiCORNE and Li+Fluids, to leverage shared infrastructure and thus advance geothermal lithium technologies and industrial scalability in a European strategic effort to strengthen domestic critical mineral supply chains.

DLE operates by pumping lithium-rich brine from reservoirs, selectively capturing lithium via adsorption or ion exchange methods, and then purifying it into lithium chloride or using electrolysis and processing the chemical into battery-grade lithium carbonate or lithium hydroxide. After extraction, the brine is reinjected to sustain geothermal reservoir pressure. However, reinjecting brine at cooler temperatures may impact geothermal systems by gradually cooling the reservoir, inducing thermal stress, altering fluid dynamics, and potentially shortening the reservoir’s lifespan. While these cooling effects are well understood, the effects of reinjecting brine with lower lithium concentrations are less known and warrant further research to prevent accelerated depletion of the resource.

Current geothermal lithium projects

Project	Company	Lithium capacity (kt/year)	Year	Country	DLE technology	Project stage
Salton Sea	CalEnergy Resources Limited and Oxy	17	Early 2030s	United States	Adsorption	Demonstration
Salton Sea (ATLiS)	Cyrg Energy	3	2027	United States	Adsorption	Pilot/feasibility study
Hell's Kitchen (P1)	Controlled Thermal Resources	4	2027	United States	Adsorption	Demonstration
Hell's Kitchen (P2)	Controlled Thermal Resources	13	Early 2030s	United States	Adsorption	Demonstration
Upper Rhine Valley	Vulcan Energy	4	2027	Germany	Adsorption	Commercial execution ready
Upper Rhine Valley	Vulcan Energy	4	2030	Germany	Adsorption	Feasibility study
UnLimited	EnBW and KIT Bruchsal	0.1	2028	Germany	Adsorption	Pilot/feasibility study
United Downs	Cornish Lithium and Geothermal Engineering Limited	0.02	-	United Kingdom	Ion exchange	Pilot/feasibility study
Weardale Lithium	Weardale Lithium	2	2028	United Kingdom	Adsorption	Pilot/feasibility study
Alsace Geothermie Lithium	Eramet and Electricite de Strasbourg	2	2030	France	Adsorption	Pilot/feasibility study
Alsace	Lithium de France and Equinor	TBD	-	France	-	Scoping
Alsace	Vulcan Energie France	TBD	-	France	-	Scoping
Cesano	Enel Green Power and Vulcan Energy & Steam Srl	TBD	-	Italy	-	Scoping
Cesano and Viterbo	Altamin	TBD	-	Italy	-	Scoping
Ohaaki	Geo40	TBD	-	New Zealand	-	-

Notes: TBD = to be determined. Lithium capacity is expressed in kt/year of lithium content and not lithium carbonate equivalent (LCE) or lithium hydroxide monohydrate (LHM) equivalent. Conversion rates used are 0.188 for LCE and 0.165 for LHM.

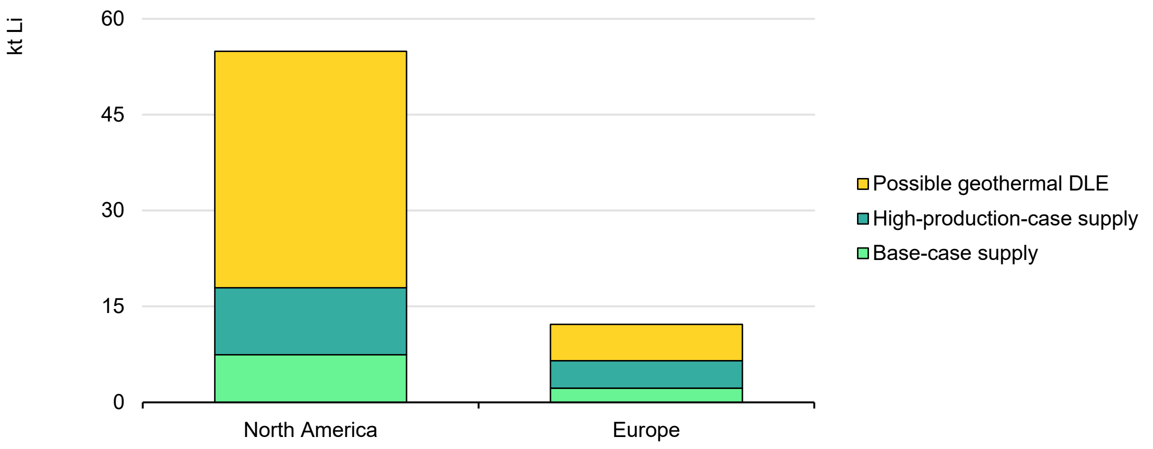
DLE is a faster approach to lithium production, with lower environmental impacts and greater public acceptance. It is modular and thus scalable and suitable for integration into new or existing geothermal plants. The two primary DLE methods are selected based on brine characteristics. Adsorption is effective for high-lithium-concentration brines, uses fewer chemicals, is more scalable and has lower upfront costs. Meanwhile, ion exchange is optimal for lower lithium concentrations or complex brines with competing ions such as sodium and magnesium, but it requires careful management of potential chemical waste. Despite its higher initial costs, it can be more economical for low-lithium brines owing to its precise ion capture capability.

No commercial geothermal lithium projects are currently operational, but several are advancing towards construction and commercialisation phases, including pilots and larger demonstration and optimisation plants, primarily within open-loop geothermal projects in the United States and Europe. Several projects are also in the early scoping stages.

Some projects also plan to incorporate battery production infrastructure, including refineries, to produce battery-grade lithium in their pilot, demonstration or optimisation stage, followed by the production of anodes and cathodes and full battery assembly. Integrating these processes will make these projects energy self-sufficient; reduce transport requirements; and enhance battery sustainability. Furthermore, these ventures have secured offtake agreements with major automakers, further supporting the commercial potential of integrated geothermal lithium projects.

If all projects in the geothermal pipeline materialise, they could produce around 47 kt/year of lithium by 2035, corresponding to 5% of global 2035 demand in the APS, which would be of particular benefit to the United States and Europe. The United States alone could produce over 37 kt/year of lithium by 2035, which amounts to five times its projected base-case supply. Europe could produce over 10 kt/year of lithium by 2035, which also amounts to five times its base-case supply and corresponds to 10% of EU EV sales. This increase is particularly critical given the widening supply-demand gap in upcoming years due to the long lead times needed to bring lithium to the market.

Lithium mining supplies in Europe and the United States, 2035



Notes: DLE = direct lithium extraction. Lithium mining covers extraction from hard rock ore, brines and clays. Supply is predicated on operating and announced mining and refining projects by country. These projections are categorised into base and high-production cases according to their probability of coming online given various factors such as financing and permitting status and feasibility studies. The European high-production case already includes some geothermal DLE production.

Benefits of integrated geothermal lithium projects

The benefits of integrating geothermal and lithium projects may be substantial because permitting, land and water access challenges – as well as access to financing – severely impact their deployment.

As geothermal developments are covered under mining legislation in many countries, common to both geothermal and lithium projects is a long list of permits, licences and other requirements, including environmental impact assessments, exploration licences, drilling permits, water-use and discharge permits, land-use/leasing and zoning permits, hazardous-material handling permits, grid connection permits, road construction or use permits, environmental permits (e.g. involving air, water and wildlife) and health and safety permits. Thus, jointly developing land-use plans and sharing infrastructure (e.g. pipelines, waste treatment facilities and drilling equipment) can help lower costs for both parties, avoid redundancies and secure access.

Co-ordinating application processes can help streamline permitting, reduce the number of separate submissions and potentially shorten approval wait times. Joint environmental monitoring can help ensure that resource extraction, water treatment, waste management and emissions are monitored collectively and are in compliance while reducing the environmental footprint.

Joint projects can also help diversify revenue streams and spread risk, making ventures more attractive to investors while enhancing project resilience. This is particularly valuable in the context of highly variable lithium prices, which are expected to remain elevated on average as EVs and energy storage solutions boost demand. Additionally, geothermal brines contain other valuable dissolved minerals (e.g. zinc and manganese) that can be recovered using similar extraction methods, further enhancing the economic potential of these brines.

These new types of projects that combine geothermal exploitation, extraction and mineral processing – thereby promoting permitting, exploration and drilling synergies – can effectively reduce capital expenditure requirements.

Chapter 5: Policy

Designing an enabling ecosystem

Targets and roadmaps

Challenges: Unlike more established renewable energy sources such as solar PV, wind and hydropower, geothermal is often excluded from energy policies and ambitions or targets. For instance, according to the UNFCCC 2023 synthesis report on nationally determined contributions (NDCs), geothermal energy is a priority mitigation option in only 9% of the NDCs submitted. This makes it difficult for the sector to gain traction and attract investment and public support.

Policy priorities: Recognising the unique features of geothermal as a firm and dispatchable source of power and heat, including geothermal in energy sector planning or modelling as part of multiple options for clean energy transitions would enhance its prominence in energy policymaking. Implementing geothermal-specific targets or ambitions and geothermal-specific technology roadmaps and implementation plans could drastically increase investor interest.

Selected policy examples: Iceland, Japan, New Zealand, the Philippines, Indonesia and Kenya have long-established policies and targets that integrate geothermal as a central component of their energy strategies. Meanwhile, the European Union has developed a geothermal-specific Implementation Plan and has included geothermal as a strategic technology in the Net-Zero Industry Act and the Critical Raw Materials Act, with lithium as a coproduct of geothermal production.

Additionally, several European countries (Austria, Ireland, Poland, Hungary, Croatia and France) have developed national geothermal roadmaps with ambitious targets, while Germany and the Netherlands focus on geothermal heating and cooling. The United States has recognised geothermal potential for power and heat generation and has incorporated it into federal and state renewable energy policies and carbon reduction targets.

Resource assessment

Challenges: Having access to accurate, standardised subsurface geological data (e.g. on reservoir volumes, temperature, flow rates, permeability and fluid chemistry) is essential to minimise geothermal project development risks. In many countries, low subsurface-data quality and limited accessibility through standardised public data-sharing platforms continue to be key challenges for geothermal developers and financiers to accurately assess project risks at the predevelopment stage.

Policy priorities: Improving data quality, accuracy and the sharing of public geological surveys is essential to address resource assessment challenges for geothermal projects. While national geological surveys have broader mandates, the creation of geothermal data repositories with open access that present data in a standardised, interoperable database could help public, scientific and private communities share and benefit from detailed geothermal data. Collaborating with the oil and gas industry – given its extensive experience in drilling – could also drastically improve data coverage and quality.

Selected policy examples: Germany, the Netherlands, Italy, the United States and France are leading the way by creating public-access geothermal repositories of all relevant data and conducting or funding campaigns to acquire new data. In addition, the European Geological Data Infrastructure consolidates geothermal and standardised data across Europe for public access. Data-sharing agreements with oil and gas companies (such as in the United States) can further improve subsurface data availability for geothermal development.

Permitting and institutional capacity

Challenges: Lengthy, complicated permitting is one of the major challenges preventing the acceleration of geothermal deployment, with long lead times translating into higher project and financing costs. In fact, the permitting of geothermal projects can take 5-10 years in many countries and reaches as much as 20 in extreme cases.

Underground resource regulation framework: In most jurisdictions, the use of geothermal resources is regulated by the same legal framework as other underground resources, such as minerals or hydrocarbons. In many cases, the legal framework for water management also applies. Geothermal heat is usually considered a national natural resource, subject to a licensing regime overseen by a national mining authority.

Existing permitting rules often do not take the minimal land and water use, lack of hazardous materials, low seismic risk and small overall footprint of geothermal projects into account. As a result, impact assessment requirements for geothermal projects are often as complex and stringent as for conventional mineral mining – disproportionate to the actual risks. For instance, if national or local laws ban mining activities in certain rural or urban areas, this ban sometimes automatically includes geothermal projects without any separate consideration.

Number of permits: Because of the stringent regulatory regimes that apply to underground works, the number of permits required for geothermal developments can be much higher than for other renewable technologies such as wind and solar. Requirements can also vary depending on the type of technology used, drilling depth and project location, among other factors. For instance, a developer in the Philippines needs to obtain 150-200 permits throughout the development process, and in the United States a geothermal project can be assessed under the National Environmental Policy Act as many as 6 times.

Stakeholder responsibility: Responsibility for various types of required permits is often divided among numerous national, provincial and local agencies and authorities, further complicating the process. In addition, the responsibilities of different agencies can overlap, leading to a lack of clarity and duplication of work. For instance, in the United States more than 15 different government agencies need to be contacted during the permitting process for a project on federal land. In California, developing a geothermal project can require interactions with eight federal, nine state and two local agencies, as well as a Native American tribal authority. In the Philippines, five different ministry departments are responsible for handling applications.

Human resources: Limited staff capacity of the many administrative offices handling geothermal project applications and a lack of technology-specific knowledge, experience and manual review processes, in addition to limited co-ordination among agencies, make permitting processes for geothermal projects longer and more complex.

Policy priorities: To accelerate the permitting of geothermal projects, improvements in multiple areas would involve: 1) modifying/adapting the legal frameworks managing underground resources by adding geothermal-specific clauses, or creating frameworks specific to geothermal projects; 2) simplifying and streamlining administrative processes by consolidating and accelerating required procedures; 3) imposing realistic but strict project review deadlines for stakeholders; 4) increasing co-operation among stakeholders; and 5) digitalising permitting review processes.

Selected policy examples: Several countries have begun to amend their legal frameworks to accelerate geothermal permitting. In Germany, a proposed policy bill includes exemptions from mining rules and strict deadlines for application processing, while in France proposed measures aim to cut permitting time in half by introducing parallel evaluation of different parts of an application. Meanwhile, the Netherlands already introduced a separate legal procedure for geothermal projects in 2022, removing geothermal from the default legal framework that historically applied to oil and gas exploration. Some countries, including Japan, are also considering allowing geothermal development in natural protection zones, as considerable geothermal resources have been found in these areas where mining activity is prohibited.

In the Philippines, geothermal projects are now being treated as strategic investments and an accelerated-permitting process has been introduced. At the same time, official recommendations in the United States include establishing a centralised federal permitting office to co-ordinate state-level work and provide necessary expertise. Another recommended measure is to exempt low-impact geothermal projects from full environmental impact assessments.

Social acceptance and community engagement

Challenges: Community concerns over geothermal energy projects have centred around the environmental impacts of drilling and well/reservoir stimulation (i.e. effects on wildlife, air quality, groundwater contamination and ecosystems due to water use) as well as on the consequences of noise, land use and induced seismicity. Some ventures have also faced social acceptance challenges because of their overlap onto indigenous lands, protected areas and popular tourist sites. All these public opposition challenges have contributed to substantial project delays and even cancellations in countries such as Japan, Kenya and Mexico. Social acceptance thus remains a significant factor in the success of geothermal energy development.

Policy priorities: Policies focusing on community engagement, environmental safeguards and benefit-sharing mechanisms could help address social acceptance challenges for geothermal projects. It is essential to engage early and transparently with communities, involving them in decision making, sharing clear and consistent information and responding to concerns about noise, environmental impacts and seismic risks while differentiating between shallow and deep geothermal projects.

Robust regulations are another key policy tool, as they can establish safeguards to help manage environmental impacts associated with land use, noise, induced seismicity and water use for lithium extraction. Furthermore, policymakers can integrate other criteria into permitting processes, including local employment quotas, commitments to improve infrastructure, profit-sharing models or reduced fees for local energy use.

Selected policy examples: A few countries have introduced approaches to engage local communities in the planning of geothermal projects, for instance Kenya and New Zealand.

Standardisation

Challenges: Internationally recognised technical standards have not been established for geothermal technologies, even though standardising and modularising commonly used materials and equipment could make them replicable, scalable, safe and efficient, which would significantly reduce their cost, minimise equipment failures and extend their lifespan. In addition, regulatory bodies often demand proof of safety and environmental compliance, a requirement that becomes more complex without established technical standards.

Policy priorities: Geothermal-specific standards are needed to address unique challenges such as handling high-temperature steam, integrating geothermal with other renewables and managing environmental and safety concerns such as induced seismicity. These standards should address all project stages, from exploration and drilling to well construction, power plant components and material use in high-temperature high-pressure environments. The International Organization for Standardization (ISO) and the International Electrotechnical Commission (IEC), in collaboration with policymakers, should take the lead in establishing a dedicated technical committee to develop geothermal-specific standards, informed by the International Association of Drilling Contractors (IADC) classification system.

Selected examples: Technical standards are developed by organisations such as the ISO and the IEC. Currently, several existing ISO standards for oil and gas drilling and for well construction also apply to geothermal projects, as similar drilling technologies and equipment are used in both industries. For example, ISO 10426 covers cementing for well integrity, ISO 11960 addresses well casing and tubing, ISO 22476-15 specifies measuring while drilling to record machine parameters during the drilling process, and ISO 17628 covers geothermal testing and thermal conductivity. The IEC, while not a geothermal-specific agency, has a range of standards relevant to the power generation components of geothermal projects. For example, IEC 60034 covers rotating electrical machines, though geothermal applications may require modifications, and IEC 60953 outlines thermal acceptance tests for steam turbines.

In addition, the IADC's Geothermal Committee, formed in 2023, introduced a well classification system in 2024 addressing the challenges of drilling, construction and long-term operation of geothermal wells. This classification is the precursor to a dedicated guideline on geothermal wells.

Financial support

Financial support for geothermal projects can target predevelopment risks through risk mitigation schemes and/or provide incentives for the purchase of power and/or heat. At least 20 countries currently provide financial support for geothermal project deployment, as summarised in the following table. Further details on risk mitigation and remuneration schemes are discussed below.

Overview of support policies for geothermal power and heat

Country	Risk mitigation scheme	Remuneration scheme
Austria	Support for deep geothermal* (grants)	None
Canada	Emerging Renewable Power Program** (grants)	Clean Technology Investment Tax Credit (tax credit) Utility PPAs, e.g. with SaskPower (unsolicited bilateral contracts)
Chile	Chile Geothermal Risk Mitigation Program (MiRiG) (subsidised loans)	Licitaciones de suministro eléctrico (auctions)
Costa Rica	Instituto Costarricense de Electricidad (ICE) (state-led development)	Instituto Costarricense de Electricidad (ICE) (state/utility-owned)
Croatia	Exploration of geothermal waters for energy purposes (state-led resource assessment)	Public competition for the award of market premiums (auctions)
El Salvador	LAGEO (state-led development)	LAGEO (state/utility-owned)
Ethiopia	Ethiopian Electric Power (state-led development) East Africa/GRMF (grants)	Ethiopian Electric Power (state/utility-owned) Utility PPAs, e.g. the Tulu Moye Geothermal project (unsolicited bilateral contracts)
France	Fonds chaleur* (public insurance)	Complément de rémunération** (feed-in premium)
Germany	Geothermal Information System (resource assessment)	Renewable Energy Law 2023 (feed-in premium)
Greece	None	New support scheme for power plants from renewable energy sources (feed-in premium)
Guatemala	Instituto Nacional de Electrificación (INDE) (state-led development)	Licitación del Plan de Expansión de Generación (PEG) (auctions)
Honduras	Empresa Nacional de Energía Eléctrica (ENEE) (state-led exploration)	Utility PPAs with ENEE (auctions)
Hungary	Geothermal Information Platform (OGRe) (resource assessment) Supporting the activities of geothermal-based heat-producing projects*,** (grants)	METÁR tender** (auctions)
Iceland	Iceland GeoSurvey (ÍSOR) (resource assessment)	None
Indonesia	PT Pertamina Geothermal Energy (PGE) and State Electricity Company (PLN) (state-led development) Geothermal Resource Risk Mitigation Project (subsidised loans) Geothermal Resource Risk Mitigation (GREM) (public insurance)	Presidential Regulation 112/2022 Concerning the Acceleration of Development of Renewable Energy for Electric Power Supply (unsolicited bilateral contracts)
Italy	GeoThopica 2.0 (resource assessment)	Renewable Energy Scheme 2024 (FER II) (auctions)

Country	Risk mitigation scheme	Remuneration scheme
Japan	Geological survey (state-led resource assessment) Government subsidy project (grants) Finance for exploration (investment) Liability guarantee for development (public insurance)	Act on Special Measures Concerning Procurement of Electricity from Renewable Energy Sources by Electricity Utilities (feed-in tariff)
Kenya	Geothermal Development Company (GDC) (state-led development) East Africa/GRMF (grants)	Policy on Licensing of Geothermal Greenfields (unsolicited bilateral contracts)
Mexico	Geothermal Financing and Risk Transfer Program (public insurance/grants) Comisión Federal de Electricidad (CFE) (state-led development)	Comisión Federal de Electricidad (CFE) (state/utility-owned)
Netherlands	ThermoGIS (resource assessment) RNES Geothermal Energy*,** (public insurance)	SDE++* (auctions)
New Zealand	Support for exploring the potential of supercritical geothermal technology (investment/loans/grants)	None
Nicaragua	Empresa Nicaragüense de Electricidad (ENEL) (state-led development)	Utility PPAs with Empresa Nicaragüense de Electricidad (ENEL) (unsolicited bilateral contracts)
Philippines	Geothermal Areas for Development (resource assessment)	Green Energy Auction Program (auctions) Open and competitive selection process (OCSP) (auctions)
Portugal	Eletricidade dos Açores (EDA) (state-led development)	Eletricidade dos Açores (EDA) (state/utility-owned)
Russia	None	RusHydro (state/utility-owned)
Switzerland	Investment grants for the exploration and development of geothermal reservoirs (grants)	Investment grants for new geothermal plants (grants)
Chinese Taipei	Geothermal Exploration Information System of Taiwan (state-led resource assessment)	2024 Renewable Energy FITs (feed-in tariff)
Tanzania	Tanzania Geothermal Development Company (TGDC) (state-led development)	Utility PPAs with TANESCO (unsolicited bilateral contracts)
Türkiye	Risk Sharing Mechanism (public insurance) Türkiye Geothermal Energy Potential and Exploration Studies (state-led exploration)	YEKDEM (feed-in tariff)
United Kingdom	None	Contracts for Difference (auctions)
United States	Funding under the Bipartisan Infrastructure Law, e.g. the Enhanced Geothermal Systems (EGS) Pilot Demonstrations (grants)	Clean Electricity Investment Credit and Clean Electricity Production Credit (tax credit) Centralised procurement in US states, e.g. California (auctions)
East Africa	Geothermal Risk Mitigation Facility (GRMF) (grants)	None
Latin America	Geothermal Development Facility for Latin America (grants)	None

*Scheme focuses on geothermal heat. **Currently closed.
Note: Schemes focus primarily on geothermal power unless otherwise stated.

Predevelopment risks

Challenges: Geothermal projects are capital-intensive and have notable resource risks during the early stages of development. These high predevelopment risks and considerable capital requirements can lead to high financing costs, reducing the economic attractiveness of geothermal ventures.

Policy priorities: Risk mitigation schemes targeting early-stage project development can be effective in accelerating geothermal deployment. Depending on market maturity, grants, subsidised loans and public insurance schemes could help reduce predevelopment risks. Alternatively, governments can carry the resource risks by undertaking exploration activities through state-owned enterprises. In co-operation with national governments, international/regional financing institutions and development banks also provide risk mitigation mechanisms.

Selected policy examples: Grants can be particularly useful when the geothermal market is still nascent or next-generation geothermal technologies are being developed. For instance, Austria, Canada and the United States have instituted grant programmes for next-generation geothermal projects. Subsidised loans, with the government or an international donor lending at a below-market interest rate, can be effective in addressing predevelopment risks, as demonstrated in Indonesia. Meanwhile, Türkiye and the Netherlands have successfully implemented public insurance schemes that take over part of the costs if drilling is unsuccessful. Government programmes vary widely in their coverage of project activities: some apply to resource exploration only (e.g. in Croatia) while others extend to plant construction and operations (e.g. in El Salvador), with other combinations in between.

In Kenya, the state-owned enterprise Geothermal Development Company (GDC) owns and explores geothermal resources and sells the steam to private power producers that develop power or heat projects. In recent years, public-private partnerships have emerged, either for exploration and drilling (with state-owned enterprises developing projects in collaboration with private companies, e.g. in Indonesia) or to provide insurance (e.g. currently being discussed in Germany).

In addition to national governments, international donors also offer risk mitigation mechanisms in emerging economies and developing countries. In general, these are grants for exploration and drilling but can also include grants for resource assessment. For instance, the Geothermal Risk Mitigation Facility (GRMF) is funded by, among other organisations, the African Union Commission and the German Development Bank (KfW) and supports projects in 13 eligible East African countries (e.g. Ethiopia, Kenya, Tanzania and Uganda). The programme provides grants for surface studies and exploration drilling and testing of reservoirs to increase project bankability. While initially focusing on geothermal power, the programme has recently extended its support to include geothermal heat.

Another example is the Geothermal Development Facility for Latin America funded by the German Federal Ministry for Economic Co-operation Development (BMZ) and the European Union. Finally, some countries implement risk mitigation schemes in collaboration with (and with funding from) international donors, such as Türkiye's Risk Sharing Mechanism or Indonesia's Geothermal Resource Risk Mitigation Project, both funded by the World Bank.

Remuneration schemes

Power

Challenges: In the absence of long-term remuneration schemes, financing capital-intensive geothermal electricity projects can be challenging. While some types of policies and regulations can effectively address predevelopment risks, other kinds can improve long-term revenue stability during a geothermal power plant's operation.

Policy priorities: In nascent markets, administratively set fixed tariffs and premiums can effectively provide long-term revenue certainty, while more mature markets can consider switching to competitive auctions to potentially reduce contract prices. Regulations enabling corporate power purchase agreements can also provide revenue certainty. In the absence of private sector interest or vertically integrated electricity markets, governments could consider taking on the revenue risk by developing and operating geothermal projects through state-owned enterprises or utilities.

Selected policy examples: Feed-in tariffs with long-term contracts are offered in Japan and Türkiye, while Germany and Greece provide feed-in premiums. In Croatia, the Netherlands and the Philippines, geothermal is included in auction mechanisms. Similarly, several single-buyer markets, including Indonesia and Ethiopia, allow for unsolicited bilateral contracts with the main utility. In El Salvador and Costa Rica, state-owned utilities have developed geothermal projects, but an increasing number of countries have privatised geothermal electricity projects developed by the government (Indonesia and the Philippines).

Geothermal district heating

Challenges: District heating networks enable the distribution of geothermal heat to various end users in urban areas or industrial hubs. However, the infrastructure is large and capital-intensive and, in many regions, fuelled predominantly by relatively inexpensive fossil fuels. In addition to the resource uncertainty inherent to conventional geothermal projects, district heating developers also face demand-related risks, which can discourage investment. While existing networks offer significant opportunities to integrate geothermal heat, cost-competitiveness with fossil fuels remains challenging.

Policy priorities: Policymakers can support the development of geothermal district heating by developing and strengthening the expertise and capabilities (including staffing) of local public authorities in heating and cooling planning and implementation. They can promote heat mapping exercises, which are essential to support planning, and improve investor visibility with detailed information and reliable data. Heat mapping consists of characterising local heating and cooling demand – identifying zones with adequate demand density as well as anchor loads (e.g. industrial facilities and public buildings with high and relatively stable heat needs) – and determining potentially matching heat sources.

Introducing zoning policies and mandating connection to district networks where they exist are also effective ways to mitigate demand-related development risks by guaranteeing an anchor load that enables economies of scale. Such connection mandates can apply to the replacement of heating systems in existing buildings or to new housing developments, for which municipalities can also set requirements in terms of density, building height, etc. District heating network retrofits and new project schedules can also be synchronised with work on transport infrastructure to minimise construction costs, traffic disruption and administrative burdens.

In combination with integrated heat planning and regulatory support, financial and economic incentives, including fiscal measures (e.g. tax credits) and debt guarantee schemes can effectively assist geothermal district heat developers and minimise risks for potential investors. Municipalities can also deploy land value capture strategies and instruments as an additional source of financing for geothermal district heating projects. Additionally, concessional financing from development banks and multilateral funds can support geothermal district heating investments, especially in regions where local interest rates are too high or financing is difficult to secure.

Selected policy examples: Heat planning and zoning strategies have been used to deploy district heating and cooling infrastructure in countries such as China, Denmark, Korea and Sweden. However, because connection-mandate zones can create natural monopolies, transparent pricing and regulated tariffs are important to strengthen consumer confidence. For instance, Sweden's 2008 District Heating Act stipulates pricing and information transparency. Not-for-profit cooperative structures and public ownership can also be encouraged to protect customers. In countries such as Iceland, district heating networks must be at least 51% publicly owned and are subject to full tariff regulation. In Denmark, Germany, Iceland, Norway and Sweden, the government offers financial incentives for investing in district network infrastructure.

Geothermal heat pumps

Challenges: Geothermal heat pumps have higher upfront installation costs than air-source heat pumps, as they require drilling and trenching for the underground heat exchanger. In addition, payback periods are relatively long, potentially up to 10 years. The high upfront costs and the relatively long payback time can be obstacles for many households and small- and medium-scale consumers.

Policy priorities: Financial incentives such as grants and tax credits can make geothermal heat pumps attractive, create demand and eventually reduce installation costs as competition and equipment standardisation expand. In addition, policies can support geothermal networks using geothermal heat pumps to deliver heating and cooling to multiple residential and commercial buildings at the same time to achieve economies of scale.

Selected policy examples: In the United States, homeowners and commercial consumers are eligible for tax credits, with additional programmes for low-income households administered at the state level. Agricultural producers and rural small businesses can also access guaranteed loan financing and grants. In Europe, 12 countries (the United Kingdom, France, Germany, Spain, Lithuania, Croatia, Ireland, Czechia, the Netherlands, Austria, Denmark, and Norway) offer grants or subsidies to encourage people to replace existing fossil fuel heating systems with geothermal heat pumps. Some countries (e.g. Austria, Switzerland, Norway and Lithuania) have extended funding to heat pump installation in new buildings. In the United States, federal and state-level low-interest loans and grants support networked geothermal systems, while municipal bonds can provide the initial capital needed to finance projects.

Remunerating generation flexibility

Challenge: Geothermal power plants are one of the few low-carbon electricity generation technologies that are dispatchable and can provide a wide range of system flexibility services such as ramping capability, frequency regulation and inertia. Although these benefits can help integrate variable renewables such as wind and solar PV into the power system, power market designs and regulations do not yet fully reflect the value of dispatchable low-carbon technologies.

Policy priorities: Electricity markets must be made to recognise the value of dispatchable low-emissions power generation capacity. They should be designed to ensure that geothermal and other low-carbon dispatchable plants are compensated in a competitive and non-discriminatory manner for their emissions-avoidance, flexibility and electricity security benefits. Furthermore, geothermal power plants need to be remunerated for the services they provide in maintaining electricity security, including capacity availability and frequency control.

Selected policy examples: Increasing system ancillary service payments and including geothermal plants in capacity markets (with system operators providing remuneration for the on-demand availability of installed capacity) are possible ways to recognise the value of geothermal power plants.

Research and innovation

Challenges: Government support for research and innovation (R&I) is critical to overcome the technical, environmental and economic barriers slowing the deployment of conventional and next-generation geothermal energy and to facilitate technology transfer from the oil and gas sector. Currently, the lack of dedicated R&I funding and infrastructure remains a key challenge.

Policy priorities: Expanding geothermal-specific R&I programmes through funds dedicated to innovative projects could support overall cost reductions, while public-private partnerships could encourage the demonstration and testing of new technologies. In addition, public funds could be used to establish specialised research facilities to test high-temperature high-pressure equipment underground.

Selected policy examples: In the European Union, key programmes – the European R&I Framework Programme and the Innovation Fund – provide substantial funding for geothermal energy. These grants typically require cofinancing, with beneficiaries contributing to cover the remaining costs. The R&I Framework Programme has funded nearly 670 geothermal energy R&I projects since the 1980s. By comparison, funding has been given to five times more wind energy and hydrogen R&I projects each since the 1990s, highlighting the disparity in funding priorities. Today the European Strategic Energy Technology (SET) Plan and Strategic Innovation and Research Agenda (SRIA) help align geothermal R&I priorities across EU member states, Iceland, Norway and Türkiye.

For instance, the Soultz project, funded by the EU R&I Framework Programme, the French government (ADEME) and the EDF since the late 1980s, pioneered extracting geothermal energy from deep fractured crystalline rock using innovative stimulation technologies and demonstrated the potential to generate electricity from deep geothermal resources, with a 1.5-MW plant currently operational. Since its launch in 2020, the European Union's Innovation Fund has supported only one geothermal project – the large-scale Eavor-Loop project in Germany – out of 116 funded projects, with 30 focused on hydrogen production and use.

In the United States, the Department of Energy's Geothermal Technologies Office has partnered with industry, academia and research facilities to fund advances in geothermal technologies. Since 2010, it has invested over USD 470 million in geothermal energy R&I, including USD 15 million for the extraction of lithium from geothermal brines. The FORGE project has helped spur R&I in next-generation geothermal, driving drilling costs down at least 20%, which has contributed to even larger reductions by Fervo Energy in the Cape Project.

There is also a need for specialised research facilities to test high-temperature high-pressure equipment underground (for example, some facilities allow testing at a depth of 1.5 km). Currently, research facilities that enable underground testing are concentrated in Switzerland, the United States, Czechia and Sweden, with Germany also planning to build a suitable laboratory.

The IEA Geothermal Technology Collaboration Programme fosters international collaboration and contributes to the alignment of research agendas among countries and industries to drive global geothermal innovation.

Jobs and skills

Challenges: A robust workforce of engineers, geologists and experienced drillers will be needed for geothermal sector expansion. So far, geothermal energy development has drawn many oil and gas sector professionals, as their experience and skillsets overlap and are highly transferable. However, enrolment in geological science and petroleum engineering programmes has been declining, particularly in advanced economies, while university and training programmes specialising in geothermal energy remain limited.

Considering the large market potential for next-generation geothermal, the lack of a skilled workforce could be a major barrier. However, this potential also presents a significant opportunity to develop new educational and training initiatives for the needs of next-generation geothermal energy.

Policy priorities and examples: A multipronged approach is essential to address challenges in building and retaining a skilled geothermal workforce. Industry, academia and governments could collaborate to establish dedicated academic programmes and specialised training initiatives like those in the United States. Capacity-building efforts can extend beyond the job market to strengthen expertise in governments and decision-making bodies, especially outside of advanced economies.

For instance, the GRO Geothermal Training Programme (previously a UN University programme) in Iceland aims to enhance skills and geological survey services globally. To bring courses to other regions, the GRO programme has established a Centre of Excellence in El Salvador for Latin America and the Caribbean countries, and another in Kenya for Africa.

The oil and gas sector also has a pivotal role to play in the workforce transition. In collaboration with geothermal enterprises, oil and gas companies could invest in talent retention and reskilling, on-the-job training and apprenticeships focused on geothermal development.

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