The Deep Heat Advantage:

A techno-economic analysis of enhanced geothermal systems in western and northwestern Canada

Gordon Brasnett, Megan Eyre, and Peter Massie

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Authors

Gordon Brasnett is a Cascade Institute Fellow on the Ultradeep Geothermal team.
Megan Eyre is a Geothermal Geoscientist formerly with the Cascade Institute.
Peter Massie is the Director of the Cascade Institute Geothermal Energy Office.

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DEEP Earth Energy Production project site in Saskatchewan (image credit: DEEP).

EXECUTIVE SUMMARY

- **This techno-economic analysis models costs and energy generation for enhanced geothermal systems (EGS) at four locations in western and northwestern Canada.**
- **Present-day costs and levelized cost of energy (LCOE) estimates for EGS are already competitive with other options for baseload electricity generation, especially in areas with hotter geothermal gradients such as the Northwest Territories and British Columbia.**
- **Modelling indicates that LCOE reductions in the range of 40-50% are achievable in a future innovation scenario with reasonable advances and efficiencies in key project aspects.**
- **EGS can provide firm, clean, cost-competitive electricity in western and northwestern Canada.**

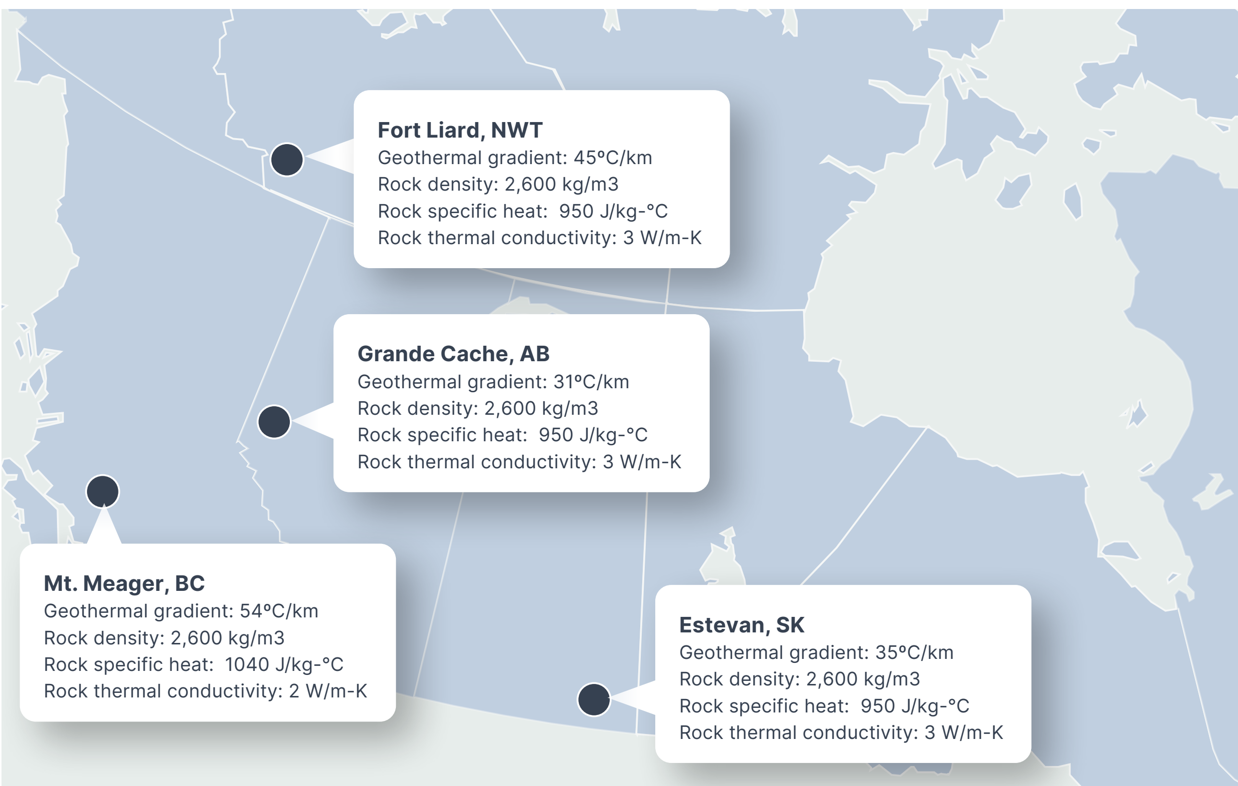
Enhanced geothermal systems (EGS) could offer a viable pathway to firm, clean electricity in Canada, especially with recent advances in drilling and reservoir stimulation and continued innovation in the space. However, because it is an emerging technology that has not yet been deployed in Canada, EGS's costs are poorly understood and can vary depending on local subsurface conditions, meaning the technology is often left out of energy-economy models and electricity system planning. This report seeks to improve understanding of EGS project costs and of the role that geothermal power can play in Canada's energy future.

The Cascade Institute conducted techno-economic analysis to model costs for developing EGS to generate electricity at four nominal project locations with representative geothermal gradients in Alberta, British Columbia, the Northwest Territories, and Saskatchewan. This analysis estimates capital and operating expenses and calculates levelized cost of energy (LCOE) at each location for two scenarios: *present day and future innovation*. We used the Geothermal Electricity Technology Evaluation Model (GETEM) within the System Advisor Model (SAM), an industry-recognized tool developed by the U.S. Department of Energy's National Renewable Energy Laboratory (NREL). All cost estimates are presented in U.S. dollars and do not include any subsidies, tax credits, or incentives.

This report presents a first-of-its-kind model of EGS power costs for four sites in Canada, drawing on the best available data and adapting established methodologies to Canadian conditions. Energy system analysts can use these estimates as inputs for electricity and energy-economy models to better understand the competitiveness of EGS power relative to other baseload technologies, as well as its stabilizing role in a decarbonized energy system.

FIGURE A:

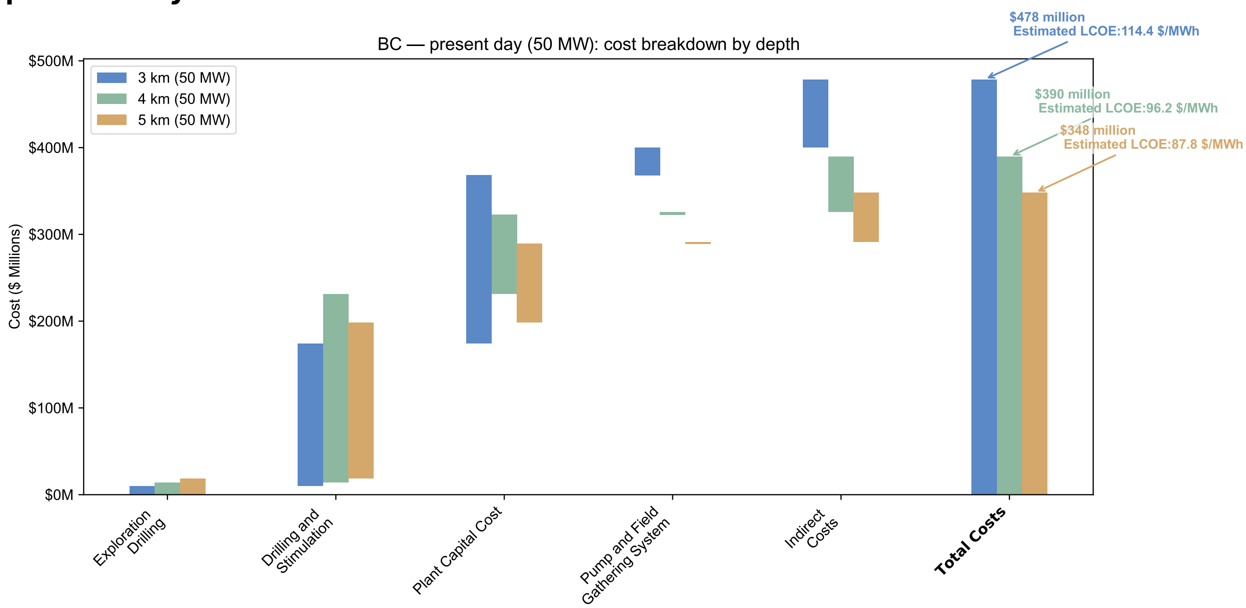
Resource parameters at selected sites in Alberta, B.C., Northwest Territories, and Saskatchewan.



For the purpose of this study, we selected sites based on locally available geothermal gradient and heat flow data, but did not account for infrastructure proximity, permitting constraints, or environmental factors.

FIGURE B:

Deeper is cheaper—cost and LCOE estimates for a 50 MW EGS project under present-day conditions



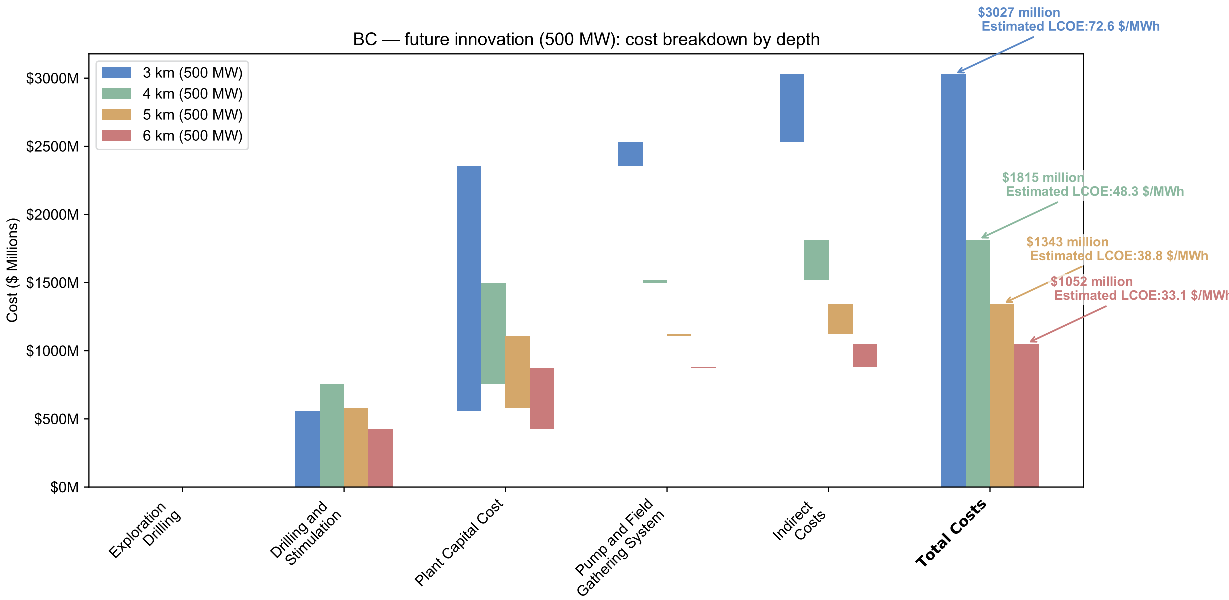
Capital cost estimates for a nominal EGS project at different depths in the Garibaldi Volcanic Belt in British Columbia under the present-day (50 MW) modelled scenario. Note the reductions in LCOE and overall project costs (in spite of higher costs per well) when targeting deeper, hotter geothermal plays due to larger energy output per producer-injector well pair. All costs in U.S. dollars.

The future innovation scenario models costs in U.S. dollars and energy outputs based on:

- advances in geoscience and well engineering to reduce the number of non-productive wells drilled when developing a project;
- improvements in reservoir engineering allowing for higher sustained flow rates per producer-injector well pair;
- continued improvements to high-temperature and high-pressure tools that aid in targeting deeper geothermal reservoirs;
- cost efficiencies such as lower $/kW operating expenses from larger-scale development; and
- reductions in drilling costs to align more closely with drilling rates recently achieved by EGS project developers in the United States.

FIGURE C:

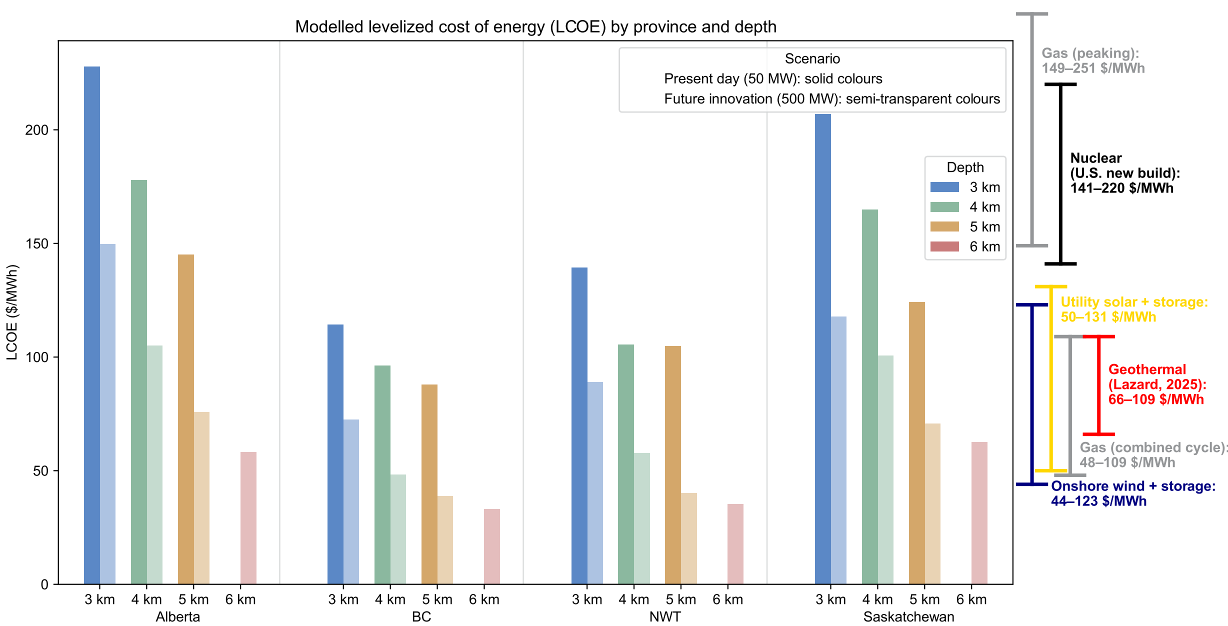
Depth and innovation drive down EGS costs in a future innovation scenario



Capital costs for an EGS project at different depths in British Columbia under the future innovation (500 MW) modelled scenario. Note that achieving a depth of 6 km results in LCOE more than 50% lower than at 3 km. All costs in U.S. dollars.

FIGURE D:

How EGS stacks up against other power sources at various depths, now and in a future innovation scenario



Calculated LCOE ($/MWh) for EGS projects at varying depths for present-day and future innovation scenarios at each of the four locations modelled in this study. For comparison, published LCOE ranges from Lazard (2025) for other comparable forms of generation: gas generation (peaking and combined cycle), new build nuclear, utility solar with storage, onshore wind with storage, and geothermal are shown as range bars on the right-hand side of the plot. All costs in U.S. dollars.

> *EGS shows significant promise as an optimal provider of clean, secure, and affordable baseload electricity generation in western and northwestern Canada.*

This analysis shows that LCOE estimates for EGS in western and northwestern Canada are already cost-competitive with other baseload technologies in some scenarios. We find that, based on present-day capabilities, an EGS project at Mt. Meager, British Columbia, or in Fort Liard, Northwest Territories, could deliver electricity with a lower LCOE than a gas peaker plant or new nuclear development. In a future innovation scenario, these already-competitive costs fall by a further 40-50%, making EGS cheaper or cost-competitive with utility solar with storage, onshore wind with storage, and combined-cycle gas at each of the four sites.

Continued investment in drilling, stimulation, and well-field optimization offers high-leverage gains that would help scale low-cost EGS development. These advances would also benefit other subsurface energy projects, including conventional and deep closed-loop geothermal. Continued R&D and new demonstration projects can help Canada overcome the remaining technical and economic barriers standing in the way of significant cost declines. With continued innovation, EGS shows significant promise as an optimal provider of clean, secure, and affordable baseload electricity generation in western and northwestern Canada.

Contents

1. Introduction

Geothermal power is a renewable energy source that harnesses the Earth's internal heat to generate electricity. This heat is accessed by drilling wells into underground reservoirs, where steam or hot water is brought to the surface and used to drive turbines that create electricity.

Unlike wind or solar power, geothermal power is not weather-dependent. It can operate continuously, 24 hours a day, making it one of the few renewable technologies capable of providing reliable, *baseload electricity*—power with a high *capacity factor* that can form the foundation of a stable, low-carbon electrical grid.

Capacity factor is the ratio of electrical energy a facility produces for a given time period to the maximum electrical energy that could have been produced if that facility were at full operation over the same time period. For example, in Alberta between 2020-2024, the capacity factor for wind projects was between 30-38%, solar was between 12-21%, combined cycle gas was between 60-75%, and combined heat and power cogeneration was 70-72% (Alberta Electric System Operator, 2025a). This analysis assumes a geothermal capacity factor of 95%.

Baseload electricity is generation with a high capacity factor that is on nearly all the time.

Despite this value, the potential role of geothermal power in Canada's energy future remains poorly understood. A key reason for this is the site-specific nature of geothermal resources and the costs required to access them. Subsurface conditions—such as temperature gradients, reservoir permeability, and drilling depth—vary widely from place to place. As a result, the costs involved in developing a geothermal power project are highly variable and cannot be easily generalized.

This variability presents a challenge for energy planners and policymakers. Because the energy and electricity models that guide utility planning processes have not yet been able to account for the cost variations that stem from changing subsurface conditions, geothermal power is typically excluded from (or underrepresented in) these models. As a result, there is no broad understanding of the important role geothermal power could play in Canada's energy future.

Geothermal power is often overlooked, with only a small amount of geothermal electricity (~6 megawatts) flowing through Canada's grid. This is less than 0.004% of the country's total installed capacity of >150 gigawatts (>150,000 megawatts) coming from geothermal, compared to 0.4% of electricity in the United States, 4.8% of electricity in Indonesia, and 8.3% of electricity in the Philippines (Smejkal et al., 2025; Canada Energy Regulator, 2023; ThinkGeoEnergy, 2025).

Power, measured in watts (W), kilowatts (kW), megawatts (MW), or gigawatts (GW), each representing a quantity a thousand times larger than the last, is a rate of electrical energy generation per unit of time. **Energy**, in the context of this report, is sustained power generation over a period of time measured in watt hours (Wh), kilowatt hours (kWh), megawatt hours (MWh), or gigawatt hours (GWh). For example, a 10 MW power generation project operating steadily for 10 hours will have generated 100 MWh of electrical energy.

The difference between power and energy, megawatts and megawatt hours, becomes particularly important when comparing the cost of technologies with different **capacity factors.** A 30 MW power generation project with a capacity factor of 30% will generate the same MWh of energy in a year as a 10 MW power project with a capacity factor of 90%. To facilitate comparison between these two project types, **levelized cost of energy (LCOE)** is a useful metric. LCOE takes the ratio of a project's costs (both capital and operating costs) to total energy generated over a project's lifetime, and is often expressed in $/MWh or ¢/kWh. However, it should be noted that LCOE does not tell the entire story and there are other factors for system planners to consider. Those factors include ensuring power generation can meet demand during peak hours and the value of ancillary services provided to the grid, such as frequency regulation, voltage control, and spinning reserves to ensure reliability (Alberta Electric System Operator, 2025b).

> *This report attempts to close the information gap that leaves Canada's geothermal power potential unrealized.*

This report attempts to close the information gap that leaves Canada's geothermal power potential unrealized. It presents a first-of-its-kind model of geothermal power costs for four sites across Canada, drawing on the best available data and adapting established methodologies to Canadian conditions. Energy system analysts can use these estimates as inputs for electricity and energy-economy models to better understand the competitiveness of EGS power relative to other baseload technologies, as well as its stabilizing role in a decarbonized energy system.

What is geothermal? One resource, many technologies

Simply put, geothermal is a reliable, renewable baseload energy source that taps the Earth's naturally occurring heat to generate clean electricity and/or heat. Geothermal reservoirs can be categorized as naturally occurring hydrothermal systems or as human-engineered enhanced geothermal systems (EGS). Hydrothermal and EGS reservoirs each have distinct geological characteristics that affect their energy production potential.

1. **Hydrothermal systems:** These naturally occurring reservoirs contain hot water or steam, which can be harnessed for power generation or direct-use applications. These systems can be harnessed with commercially available geothermal power-generating technology. Hydrothermal systems are subdivided into:

    - **Volcanic systems:** High-temperature geothermal resources (>200°C at depths shallower than 1 km) are typically found in regions of active or recent volcanism and have historically been the primary sites for geothermal power development. Although these resources have great potential, they are geographically limited. In Canada, the Mount Meager volcanic complex in British Columbia represents a promising example of this type of geothermal play.
    - **Fracture-controlled systems:** These systems rely on naturally occurring fractures or faults that enhance fluid circulation and facilitate heat transfer from high-temperature (>200°C) rocks. They are typically found in tectonically active regions, such as parts of Yukon, British Columbia, and the Northwest Territories.
    - **Hot sedimentary aquifers:** These deep (>2 km), porous, and permeable rock formations contain saline water at moderate temperatures (50-150°C) and are common in the Western Canada Sedimentary Basin, including Alberta, northeast British Columbia, and Saskatchewan.

    Most identified hydrothermal resources in Canada are low-temperature (<150°C) hot sedimentary aquifers or fracture-controlled systems, with the exception of notable volcanic systems like Mount Meager. As shown in Figure 1, hydrothermal geothermal resources tend to be concentrated in western and northwestern Canada, but outside select locations, their economic viability for power generation is marginal due to their modest temperatures and the large capital cost required to drill wells that can deliver required flow rates. While some hydrothermal resources could support direct-use applications (for example, industrial process heat or district heating), large-scale power production remains limited.

2. **Enhanced geothermal systems (EGS):** Unlike hydrothermal systems, EGS does not rely on naturally occurring permeability to support circulation of fluid through the geothermal reservoir. Instead, permeability is engineered via techniques such as hydraulic stimulation to create fracture networks. Fluid circulates through the fracture network in the geothermal reservoir, extracting heat from the rock. EGS enables access to medium-to-high-temperature resources (150°C to greater than 250°C) that would otherwise not be viable for geothermal development.

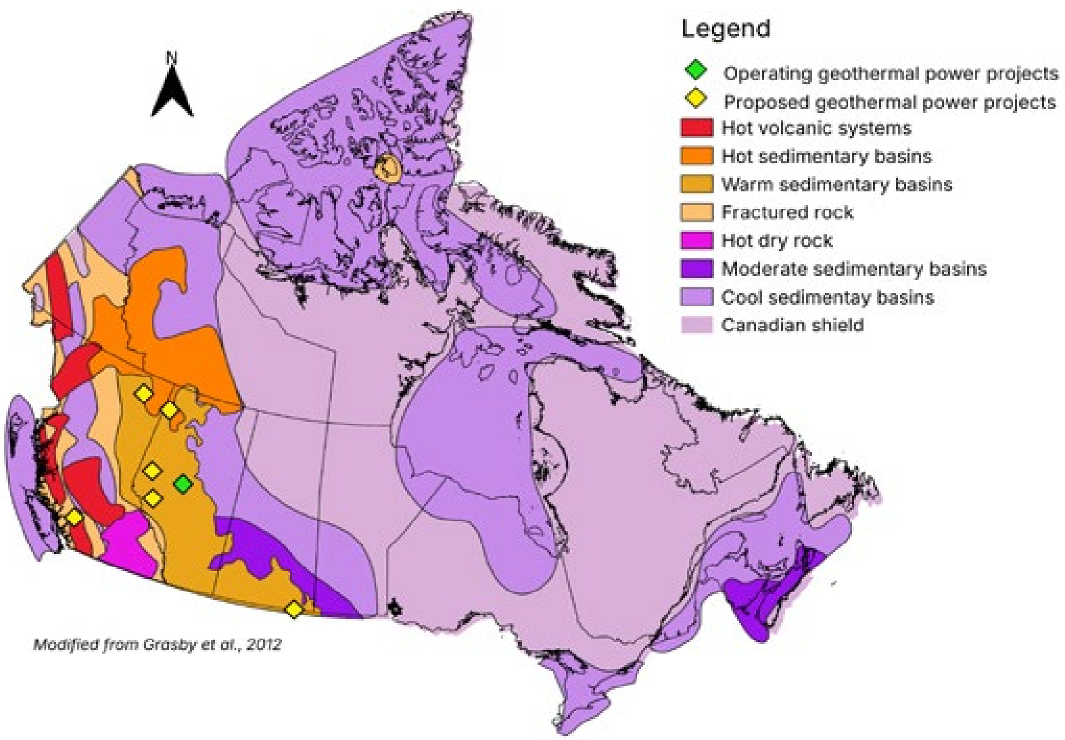
A noteworthy third geothermal technology that does not rely on fluid-reservoir interactions are Advanced Geothermal Systems (AGS) or closed-loop systems. As with EGS, AGS represents an innovation that expands geothermal development into regions without high naturally occurring permeability.

3. **Advanced geothermal systems (AGS):** Also known as closed-loop geothermal systems, AGS represents a new well completion approach rather than a distinct geothermal resource type. Unlike hydrothermal or EGS systems, which require fluid to flow through the pore space of the high-temperature rock itself, AGS uses sealed, closed-loop wells, often drilled with extended multi-lateral legs, to circulate a working fluid that extracts heat from the surrounding hot rock through conduction.

AGS was not included in this techno-economic analysis. The results of ongoing research and pilot projects, such as the first commercial, deep, closed-loop project, which is being developed by Eavor Technologies in Geretsried, Germany, can help refine estimates for key AGS costs such as drilling and completion costs for deep multi-lateral wells. Techno-economic analysis for deep closed-loop geothermal systems could be a focus for future work, with results providing utilities and energy modellers with a better understanding of AGS's potential contribution to Canada's geothermal energy landscape.

FIGURE 1:

Country-wide mapping of geothermal resources (modified from Grasby et al., 2012).

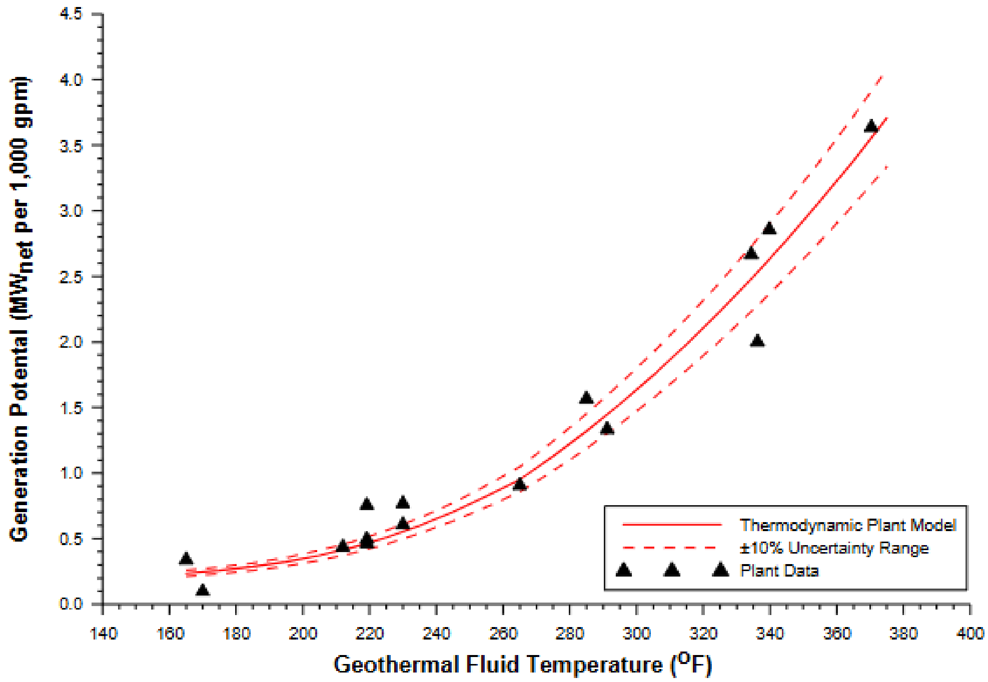


Note the vast areas in shades of purple that require next-generation geothermal technology (either EGS or AGS) for geothermal development.

For all types of geothermal technologies that generate electricity, power production is proportionate to the heat energy that is extracted from the subsurface. Fluid temperature and flow rate are two critical factors that determine power plant output and overall project economics. Lower-temperature resources generate smaller amounts of energy than higher-temperature resources (Figure 2). To generate the same amount of power as higher-temperature resources, low-temperature resources would need to flow at higher rates. Geothermal regimes that can support higher temperatures and sustain higher flow rates are thus more viable for electricity production than locations that cannot.

FIGURE 2.

Net geothermal power generation (per 1,000 gallon per minute production rate) as a function of fluid temperature (Sanyal & Butler, 2005).



The role of EGS in unlocking Canada's geothermal potential

To expand geothermal power generation in Canada and globally, developers must access deeper, hotter resources, which are abundant but generally lack the natural permeability required for fluid circulation at the rates required for a viable geothermal project. Both EGS and AGS have the potential to overcome the need for natural permeability: EGS by creating engineered reservoirs and AGS by running longer lateral wellbores through hot rock to extract heat from the formation. This report focuses on techno-economic modelling of EGS in the Canadian context.

Historically, energy analysts have considered EGS uneconomic due to high drilling and stimulation costs, along with long-term performance concerns related to thermal short-circuiting or fluid loss within the engineered reservoir. However, recent technological advancements, including improved drilling efficiency and enhanced reservoir stimulation techniques, are expanding the field of geothermal opportunities, lowering project costs, increasing power output, and making geothermal power competitive with other baseload or dispatchable energy sources. These innovations have pushed EGS into the spotlight as a potential source of clean, secure, and affordable baseload power that can be deployed outside of the hotspots where conventional geothermal projects have been developed.

Key innovations driving EGS development include:

- **Improved drilling technology**—Advances in drilling techniques are reducing well costs, enabling access to deeper, hotter reservoirs. Higher temperatures not only increase the total energy available for conversion to electricity but also improve the efficiency of power generation technologies. Companies such as Fervo Energy are achieving improvements in drilling by re-purposing techniques and technologies from oil and gas such as polycrystalline diamond compact (PDC) drill bits and real-time fiber optic data logging, while novel high-temperature drilling innovations such as plasma and millimeter wave drilling are also emerging on the horizon (Pearce & Pink, 2024).
- **Optimized well field design**—Adjusting well length, spacing, and injection-to-production ratios can reduce pressure and pumping requirements, improving overall system economics. Horizontal wells, which were rarely used in conventional hydrothermal projects, are now being adapted from oil and gas by EGS developers such as Fervo Energy.
- **Advanced stimulation techniques**—Enhancing reservoir permeability ensures sufficient and even fluid circulation throughout the geothermal reservoir, increasing energy recovery rates while reducing the likelihood of fluid loss.

With these innovations, EGS could unlock medium- to high-enthalpy geothermal resources across Canada, particularly in regions with high heat flow but limited natural permeability. If these cost reductions continue, EGS could become a cost-competitive and scalable source of clean, reliable energy.

Enthalpy is the energy content per unit mass of a fluid (commonly expressed in kJ/kg)and is essentially a measure of the extractable thermal energy contained in geothermal fluids.

What is techno-economic analysis?

Techno-economic analysis is a method for understanding the key drivers of cost and performance for a given technology or set of technologies. Analysts use it to model the individual components of a technology and map the relationships between them. People commonly refer to energy technologies like wind or solar as singular entities. But techno-economic analysis approaches wind and solar as complex systems of technologies. For example, a wind turbine is made up of components such as blades, nacelles, and towers that must each be sourced and manufactured. By assigning these components parameters, including costs, efficiencies, and learning curves, analysts can explore how different configurations of these components and changes to their various parameters influence overall costs.

System planners, energy modellers, policymakers, and project developers often use techno-economic analysis to estimate key metrics such as capital and operating costs and levelized cost of energy, for different sources of power. Perhaps more importantly, they can use techno-economic analysis to identify which improvements would have the greatest impact on the cost or performance of an energy system. Conversely, they can use it to identify dead-end technologies that should not be pursued.

Consequently, techno-economic analysis is a critical tool for developing an informed set of innovation priorities and setting an R&D agenda that takes smart risks and seeks to maximize the impact of scarce funds.

Techno-economic analysis is a particularly useful tool for geothermal power for several reasons. First, although geothermal is a mature technology, with conventional hydrothermal projects having operated around the world for several decades, analysts generally lack a clear picture of costs and performance due to the site-specific variability of the hydrothermal resources that have made up the vast majority of existing geothermal projects. Average costs obscure large variations across projects. This makes it difficult for energy system modellers to develop generalized costs estimates that benchmark geothermal against other energy technologies. Whereas the capital costs for technologies like wind and solar are generally fixed, geothermal capital costs tend to be coupled to the technical and site-specific subsurface characteristics associated with a given location.

Second, many new geothermal power production methods are emerging, particularly EGS and AGS. Each method has a unique set of benefits and challenges. Rigorous techno-economic analysis enables project proponents to assess which system would be optimal in a given context. Furthermore, AGS and EGS may interact with other innovations including novel drilling techniques and technologies that enable the use of superhot rock. Techno-economic analysis can facilitate a better understanding of interactions across these technologies and identify where complementary and competitive dynamics exist.

Third, and perhaps most importantly, techno-economic analysis is well suited to navigating the high complexity of geothermal projects. Geothermal power is not a single technology, but a system of systems. Site characterization, exploration, well construction, pumping, and power generation are all themselves systems that include multiple technologies. These systems are interconnected and can have a significant impact on a project's overall cost and performance. For example, effective reservoir characterization of in-situ pressure and stress conditions determines the pumping power required to produce and re-inject fluids from the geothermal reservoir, which in turn determines the size of a downhole electric submersible pump, which also impacts well design. The optimal configuration for a geothermal development is dependent on site-specific characteristics, including depth of the geothermal reservoir, in-situ temperature, porosity, permeability, and other factors.

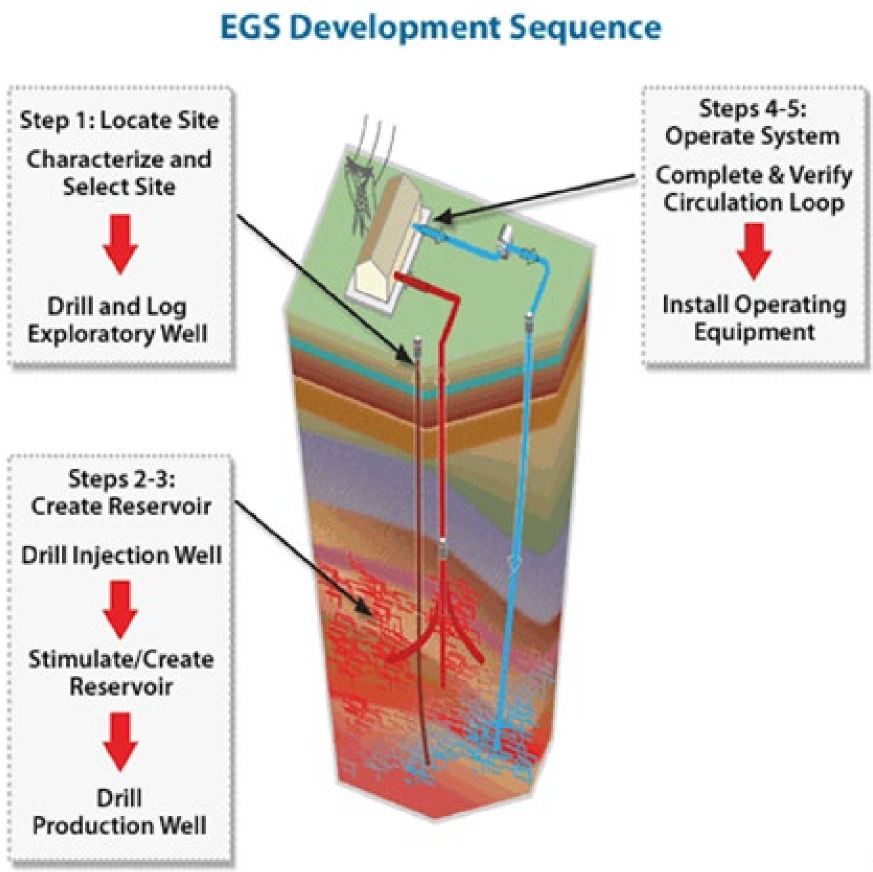
Overview of an EGS project

The proponent of an EGS project undertakes a series of steps, each involving multiple technologies, techniques, and expertise:

- **Site characterization** occurs prior to a geothermal project being developed. The proponent will undertake a series of geological, geophysical, engineering, environmental, and economic analyses to determine its feasibility.
- **Exploration** entails drilling wells to confirm the resource and to obtain additional in-situ data to inform well design and the project development plan. Upon confirmation of the resource, the proponent can proceed with detailed design and the full project build-out.
- **Well construction** involves drilling one or more production and injection wells that intersect the target reservoir. Operators typically install downhole or surface pumps, which flow the geothermal fluid from the reservoir to the surface, through the surface plant, and back through the injection well or wells to the reservoir.
- **Reservoir creation** for EGS projects involves stimulating the reservoir between the production and injection wells through hydraulic fracturing to enhance or create permeability within the reservoir.
- **Surface infrastructure** varies depending on the temperature of the resource but commonly includes pipelines, turbines, cooling towers, and generators. Power generation uses either binary or flash turbines.

A typical EGS development sequence is illustrated in Figure 3.

FIGURE 3.
Schematic diagram illustrating the components of developing an enhanced geothermal system (United States Department of Energy, n.d.).



For further detail explaining how each of the above-discussed elements were applied to this techno-economic analysis, please refer to the Appendix.

2. Methodology

The goal of this analysis is to model the present-day and future economics of EGS power generation projects in Alberta, British Columbia, the Northwest Territories, and Saskatchewan. These estimates are notional geothermal projects and do not represent existing projects that are currently being pursued for development.

To standardize the approach and ensure comparability across different locations, this analysis uses the Geothermal Electricity Technology Evaluation Model (GETEM) within the System Advisor Model (SAM) tool (National Renewable Energy Laboratory, 2025).

Techno-economic analysis with GETEM

GETEM is a comprehensive techno-economic analysis tool developed by the United States Geothermal Technology Office to estimate the levelized cost of energy (LCOE) for geothermal power generation based on project-specific resource conditions and technology parameters (United States Department of Energy, 2016). GETEM allows for the assessment of both hydrothermal and EGS resources, with both flash-steam and air-cooled binary power plant configurations. Key capabilities of GETEM include:

- estimating capital and operational costs for exploration, drilling, plant construction, and pumping;
- simulating power plant performance based on temperature, flow rates, and efficiency; and
- assessing the impact of future innovations on costs.

In this study, we apply GETEM to analyze the current economic landscape of EGS projects across Alberta, British Columbia, Northwest Territories, and Saskatchewan, using regionally relevant ambient temperatures, thermal gradients, reservoir depths, and productivity parameters. We also explore future cost-reduction scenarios based on anticipated improvements in drilling technology, reservoir stimulation techniques, learning-curve effects, and other factors. This analysis will provide insights into the viability of EGS development in western and northwestern Canada under both present-day conditions and future technological advancements.

These results should be considered a first step towards understanding geothermal power production costs in Canada. GETEM is not a substitution for detailed project-level design, so we note that more granular, site-specific analysis should guide future work by geothermal developers (see “Modelling challenges in GETEM” below).

Scenario design and key assumptions

To assess both present-day and future cost trajectories, we developed two scenarios:

1. **Present-day scenario:** Represents current industry conditions using conservative cost and performance assumptions.
2. **Future innovation scenario:** Incorporates anticipated advancements in drilling efficiency, reservoir stimulation, and plant design, based on demonstrated improvements from recent projects (e.g., Fervo Energy, Utah FORGE).

Site selection

For the purpose of this study, we selected sites based on geothermal gradient and heat flow data, but did not account for infrastructure proximity, permitting constraints, or environmental factors. Table 1outlines the site-specific parameters used in the analysis.

TABLE 1:

Table 1. Location-specific resource parameters at selected sites in Alberta (AB), British Columbia (BC), Northwest Territories (NWT), and Saskatchewan (SK).

Province	Geothermal gradient (°C/km)	Weather file*	Rock density (kg/m³)	Rock specific heat (J/kg-°C)	Rock thermal conductivity (W/m-K)
AB	31	Grande Prairie	2,600	950	3
BC	54	Pemberton	2,600	1,040	2
NWT	45	Fort Liard	2,600	950	3
SK	35	Fargo	2,600	950	3

* Weather files were selected based on proximity to the site and availability of required data such as wet bulb temperatures. Ambient air temperatures impact the efficiency of converting thermal power generated from producing hot fluids from the subsurface into electricity with cooler air temperatures improving power plant efficiency.

Alberta

In Alberta, the area north-northwest of Grande Cache was selected as the preferred site for a model EGS development due to its combination of moderate-to-high heat flow (~70-80 mW/m²), a stable thermal gradient (~31°C/km), and deep basement depths (~4-5 km). While other regions in Alberta exhibit locally higher thermal gradients (e.g., ~54°C/km), these anomalies are primarily confined to the sedimentary column, with basement depths of only ~1.5 km. There is a risk that the thermal gradient will drop upon reaching the high-conductivity Precambrian basement, resulting in lower-than-expected temperatures at target depths.

In contrast, the Grande Cache region provides a more reliable and scalable thermal resource, where a deeper Precambrian basement allows for sustained heat retention and higher temperatures at shallower drilling depths (≥150°C at ~5 km). Additionally, potential radiogenic heat production from granitic basement rocks in this region may further support a sustained thermal gradient, enhancing long-term EGS viability.

British Columbia

Mount Meager is Canada's most well-characterized geothermal resource, with a high conductive thermal gradient of 54°C/km (Grasby et al., 2022). A number of exploration wells and full-sized production wells have been drilled at the site over the past 50 years. These wells have confirmed elevated subsurface temperatures (>230°C at 2.5 km), demonstrating a significant heat resource (Geoscience BC, 2017).

Northwest Territories

We selected the area east of Fort Liard in the Liard Basin to model an EGS site in the Northwest Territories. We chose this area because of its high heat flow values of ~80-90 mW/m² and geothermal gradients of 40-45°C/km, suggesting favourable subsurface temperatures (Majorowicz & Grasby, 2021). The area also has deep sedimentary cover, with basement depths of 2-2.5 km, providing an insulating effect that helps retain heat.

Saskatchewan

Southeastern Saskatchewan presents a promising opportunity for EGS development due to its favourable heat flow (~60-70 mW/m²) and moderate thermal gradient (~30-35°C/km) (Majorowicz & Grasby, 2010). Deep well data from the Western Canada Sedimentary Basin indicate that temperatures exceeding 120-150°C can be reached at depths of 3.5-5 km, making it a viable candidate for geothermal power generation.

One of the key advantages of the Estevan area is the relatively moderate depth to basement, which ranges from approximately 3-3.5 km in the region (Weides & Majorowicz, 2014). This depth allows for a reasonable balance between temperature potential and the technical feasibility of drilling. While the basement rock itself may have higher thermal conductivity, the region's sedimentary cover provides an insulating effect that could maintain favourable temperature conditions at these depths, supporting the potential for an economically viable geothermal resource.

Input parameters and assumptions

Plant size

Two plant sizes are modelled in this analysis: 50 MW for present-day conditions and 500 MW for the future innovation scenario, reflecting the scaling potential of EGS. The key inputs used in each scenario are shown in Table 2.

While the global average generating capacity of geothermal power plants was ~38 MW as of seven years ago, as estimated by Uihlein & European Commission (2018), the 50 MW plant capacity was chosen for the present-day scenario as advances made by Fervo Energy in the EGS space have demonstrated that a single production well at their Cape Station EGS site was able to maintain a sustained output of 8-10 MW, with a peak output of 12 MW (Norbeck et al., 2024). Therefore, our analysis concluded that 50 MW is readily achievable for a plant consisting of several production wells with current EGS technology. Additionally, Fervo Energy intends to build out its Cape Station site to 500 MW capacity by drilling more production and injection wells, extending the lateral length of each well, and adding turbines. Therefore, the future innovation scenario was set to match this project size at 500 MW.

It is worth noting that GETEM accounts for parasitic load requirements when determining the number of wells needed to achieve the net plant capacity. The total power generated is therefore typically higher than the specified net capacity, to account for internal power consumption. For example, in the 50 MW scenarios, the total power generation may, for example, be around 54 MW in some scenarios, ensuring that after deducting parasitic losses—such as pumping and cooling requirements—the net output remains at 50 MW.

TABLE 2:

Key input parameters for techno-economic analysis of present-day and future scenarios

Parameter	Present-day case	Future innovation case
Plant size	50 MW (8-32 wells)	500 MW (34-100+ wells)
Injectivity index	3,000 lb/hr-psi	7,645 lb/hr-psi
Productivity index	2,500 lb/hr-psi	6,370 lb/hr-psi
Flow rate per production well	75 kg/s (binary) 60 kg/s (flash)	125 kg/s (binary) 80 kg/s (flash)
No. of exploration wells	3	2
Ratio of injection wells to production wells	1	1
Well type	Deviated liner	Deviated liner
Well size	Larger diameter	Larger diameter
Well drilling cost curve	Baseline * 0.78	Ideal
Drilling success rate	80%	95%
Reservoir stimulation success rate	85%	95%
Fixed operating cost	US$150/kW	US$99/kW
Contingency	0%	0%
Effective tax rate	15%	15%

Drilling and completion

An important aspect in any geothermal project is drilling cost, with drilling activities accounting for between 30-57% of the cost of bringing a geothermal project online (Akindipe & Witter, 2025). The GETEM tool estimates drilling costs using cost curves that were initially derived by Lowry et al. (2017) using the Well Cost Simplified model for the U.S. Department of Energy's GeoVision report. Drilling cost curves were generated based on well geometry (vertical vs. deviated), well size (large diameter vs. small diameter), and depth (1-7 km).

Each drilling cost curve is modelled assuming differences in drilling performance (rate of penetration, bit life, number of cased intervals, etc.) and well design (for example, the number of cased intervals) to create a Baseline (most conservative), Intermediate 1, Intermediate 2, and an Ideal (most optimistic, assuming maximum drilling efficiency and minimal costs) cost curve. The well cost curves for deviated wells in GETEM assume a lateral length of 1,000 ft (~305 m) at target depth (Lowry et al., 2017). In other words, well costs are not available for different lateral lengths. Nevertheless, the tool still provides reasonable cost estimates in line with real drilling data.

In each scenario, we assume that large, deviated wells will be drilled, as larger wells can accommodate more flow and deviated/horizontal wells provide greater access to the stimulated reservoir. The present-day scenario assumed the Baseline drilling cost curve with a 22% cost reduction, in line with the findings of Akindipe and Witter (2025), who noted an 18-26% reduction in costs between the Baseline curve and drilling costs from recent commercial and demonstration projects in the United States. Note that GETEM had not yet implemented proposed updates by Akindipe and Witter (2025) at the time of writing, so we manually updated them in this analysis.

The drilling cost curve associated with the Ideal scenario assumes that innovations in drilling technology and reduced material costs result in savings of 50%-75% relative to the Baseline curve. This is the cost curve scenario we chose for the future innovation scenario. This assumption is justified by several factors. First, existing EGS sites such as Fervo Energy and Utah FORGE have demonstrated significant advancements in drilling performance in just the past two years. Capital cost estimates have fallen significantly, and NREL estimates that well costs may have dropped 26% compared to the Baseline curve (Akindipe and Witter, 2025). Furthermore, there is a diverse portfolio of drilling innovations with the potential for additional cost reductions. Finally, the need for a high number of wells implies significant potential for cost reductions from learning by doing. Similar technologies, such as unconventional oil and gas, have experienced rapid learning rates.

In the exploration phase, we assume that three small-diameter exploration wells are drilled in the present-day scenario to confirm the geothermal resource and establish in-situ rock properties that inform the optimization of design criteria for an EGS project—properties such as well spacing, stimulation and operating pressure, and the number of stages. In the future innovation scenario, we assume that one small-diameter exploration well is drilled to obtain the data required to optimize an EGS project design. The decrease in well numbers assumes that learnings from first-of-their-kind EGS projects will result in improved knowledge for nth-of-their-kind projects. Large-diameter exploration wells for eventual conversion to production or injection wells were not considered in this analysis.

The drilling success rate and stimulation success rate for the present-day and future innovation cases were based on the NREL 2024 moderate and advanced scenarios from their Annual Technology Baseline data. These values align with current industry drilling and stimulation successes (NREL, 2024; Norbeck et al., 2024).

Reservoir parameters

The assumed flow rates per production well, productivity index, and injectivity index in the present-day scenario align with NREL's Annual Technology Baseline moderate scenario assumptions for EGS, while the future innovation scenario follows NREL's advanced scenario assumptions (Table 2). According to NREL (2024), these values reflect recent industry trends and the reservoir performance required for commercial operations, making them well-suited for Canadian geothermal models. However, in the future innovation scenario, we increase the assumed flow rate for binary plants from NREL's advanced scenario assumption of 110 kg/s to 125 kg/s based on recent industry performance, particularly Fervo Energy's Cape Station project, where initial production reached 120 kg/s before stabilizing at 93 kg/s. The initial production rate demonstrates the well's capability, and 125 kg/s was chosen as an aspirational yet attainable flow rate, reflecting anticipated and continued advancements in reservoir development. We accept GETEM's default parameters for rock density, specific heat, and thermal conductivity for Alberta, Northwest Territories, and Saskatchewan, due to the uncertainty in subsurface geology in these areas at the target reservoir depths. In these areas, the reservoir rock type (sedimentary vs. granitic basement) depends on depth, and the physical properties of granitic basement in each study area require more detailed analysis.

Given the high-level nature of the analysis in this study, applying default rock parameters was the most practical approach. In contrast, the geology at Mount Meager, British Columbia, is characterized as a volcanic edifice composed of basalt, andesite, dacite, and pyroclastic units. Due to this geological complexity, we estimate the specific heat (1,040 J/kg·°C) and thermal conductivity (2 W/m·K) of basalt for the British Columbia cost models (Table 1), based on values from Robertson (1988) and Grasby et al. (2012).

Operational costs

Fixed operational and maintenance costs depend on the rated capacity of the plant and are defined in US$/kW. We estimate the present-day operating expense costs to be $150/kW, and future innovation operating expense costs to be $99/kW, in line with NREL Annual Technology Baseline estimates for EGS. NREL's Annual Technology Baseline found that operational costs decreased by 23% since 2019 based on analysis of proprietary geothermal industry data (NREL, 2024). This rate of decline justifies the assumed reduction in operating expense costs in the future innovation scenario.

Cost assumptions and adjustments

In the GETEM tool, cost multipliers associated with materials needed for geothermal plant construction are derived from the Producer Price Index, which tracks price changes for raw materials and industrial goods. At the time of writing, the most recently available Producer Price Index multiplier within GETEM is from 2022; we used this value in this analysis. While material costs have likely changed since 2022, adjusting to 2025 costs would require using an alternative inflation metric, such as the Consumer Price Index. However, it should be noted that the Consumer Price Index is less volatile than Producer Price Index and reflects changes in consumer goods and services rather than industrial materials. Since geothermal plant construction costs are more closely linked to Producer Price Index trends, and more recent Producer Price Index data is unavailable, keeping the analysis in 2022 dollars provides the most relevant cost estimate for this study.

Modelling challenges in GETEM

Despite GETEM's utility, we encountered some challenges when modelling conditions that approach the limits of the range of values encoded in the tool, such as greater depths (5 km and 6 km). GETEM is a valuable tool for geothermal techno-economic analysis, but as geothermal technology evolves and projects push into new operational depths, the model will require periodic updates to ensure accurate cost assessments and technical modelling capabilities.

We occasionally encountered an issue with how the software handles production pumping for binary plants. GETEM assumes that all binary plants require a production pump, but in cases where the production well is artesian (meaning it flows to surface without the need to pump), the model assigned zero production pumps due to a calculated negative pump work value (in W-hr/lb). This created an error in the software program and resulted in an undefined LCOE.

To resolve this, we incrementally increased the production well flow rate until GETEM correctly assigned a production pump and eliminated the error. Although maintaining consistency in non-site-specific parameters like flow rate is preferable for techno-economic comparisons across provinces and depths, this adjustment was necessary to ensure physically meaningful results and valid cost calculations while preserving the integrity of cross-site comparisons.

A second issue we sometimes encountered, also more commonly at greater depths, relates to the calculation of injection pump size, which can sometimes result in a negative value. This propagated into injection pump costs of “NaN” (not a number), ultimately resulting in an undefined LCOE. The cause of this negative injection pump size is unclear, but it suggests a potential issue with how GETEM handles pressure balance and injection pumping requirements under certain conditions. Since having zero injection pumps may not always be possible, a reasonable workaround was to manually calculate total pumping costs by summing the valid production pump costs, surface equipment, and installations costs, and then setting the NaN injection pump cost to zero. This adjustment ensured that the LCOE calculation remained valid while maintaining consistency in cost estimation. (Please note: SAM updates developed and made public by NREL following this analysis have flagged enhancements to the geothermal power component.)

Additionally, we were unable to use other built-in functions in GETEM, such as calculating the temperature loss in the production well, due to an “unknown error.” The models therefore assume zero heat loss in the production wells, which is expected to be a reasonable assumption given the high flow rates of the geothermal systems resulting in a short transit time in the wellbore between the reservoir and surface, and thus marginal temperature difference between reservoir temperature and production temperature.

Finally, some of the pumping issues noted above hindered the use of GETEM’s built-in optimization modules, such as the “Geothermal Plant Efficiency Optimizer” macro that calculates the optimum plant efficiency of a binary geothermal plant that minimizes the LCOE. Therefore, where applicable, the plant efficiency for binary plants was set at 80% of the maximum possible plant efficiency (i.e. Carnot efficiency). It is possible that a lower LCOE for the binary plants modelled herein could be achieved with further refinements.

While these challenges required workarounds, they highlight the need for ongoing improvements to modelling tools as geothermal technology advances. As new depths, well configurations, and plant efficiencies are explored, GETEM will require frequent updates to accurately capture the economic viability of next-generation geothermal projects.

3. Results

We modelled costs at depths of 3 km, 4 km, and 5 km, with an additional scenario at 6 km included only for the future innovation scenario.

Table 3 presents the calculated LCOE for each case in ¢/kWh, while Figure 4 presents the calculated LCOE for each case in $/MWh. This analysis does not include cost savings from subsidies or incentives such as investment tax credits.

> *EGS power could achieve extremely competitive costs (below 4¢/kWh in some cases) for clean, baseload power.*

In nearly all cases, the modelled LCOE decreases with depth across all provinces. In the present-day scenario, estimated LCOE results indicate that in some locations, primarily due to well costs and plant capital costs, EGS is more expensive than other power generation. However, future innovation scenario simulations incorporating technological advancements show a significant reduction in LCOE, suggesting that EGS power could achieve extremely competitive costs (below 4¢/kWh in some cases) for clean, baseload power.

TABLE 3:

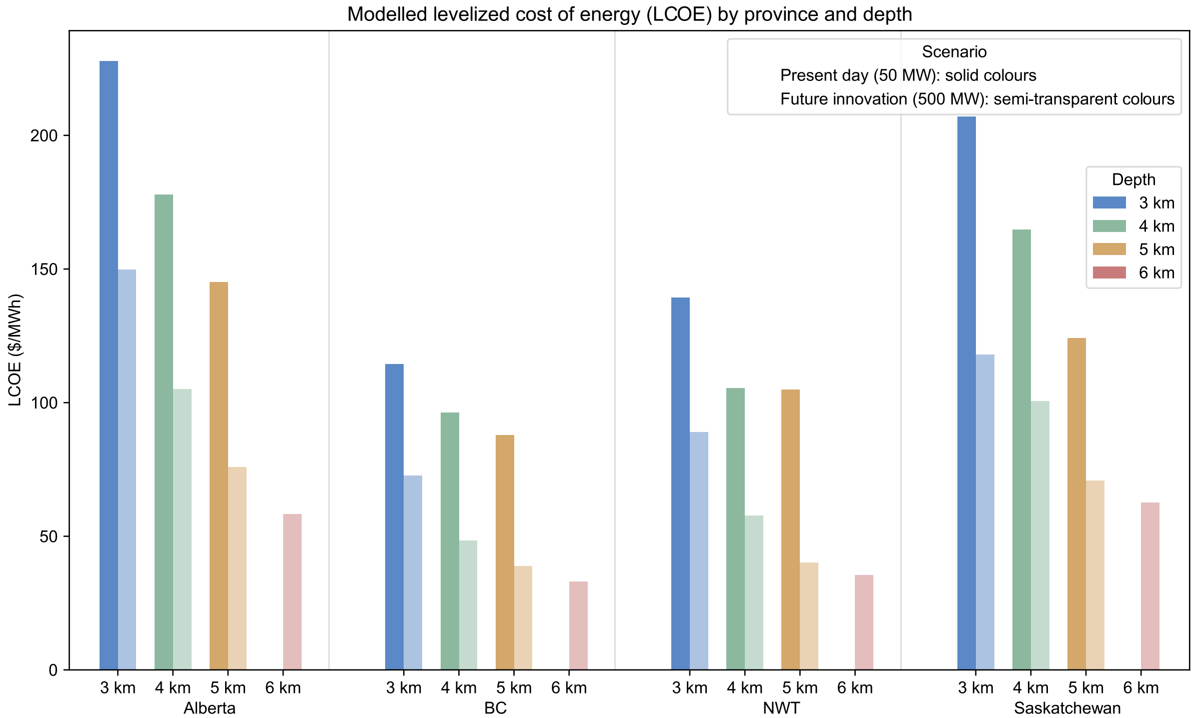
Table 3. Calculated LCOE (¢/kWh) for EGS projects at varying depths for present-day and future innovation scenarios.

	Present-day scenario LCOE (¢/kWh)			Future innovation scenario LCOE (¢/kWh)			
Province	**3 km**	**4 km**	**5 km**	**3 km**	**4 km**	**5 km**	**6 km**
AB	22.78	17.79	14.51	14.97	10.5	7.58	5.83
BC	11.44	9.62	8.78	7.26	4.83	3.88	3.31
NWT	14.11	10.33	10.52	9.08	5.82	3.96	3.54
SK	20.7	16.48	12.42	11.79	10.06	7.08	6.25

All costs in U.S. dollars.

FIGURE 4

Calculated LCOE (US$/MWh) for EGS projects at varying depths for present-day and future innovation scenarios.



All costs in U.S. dollars.

Present-day scenarios

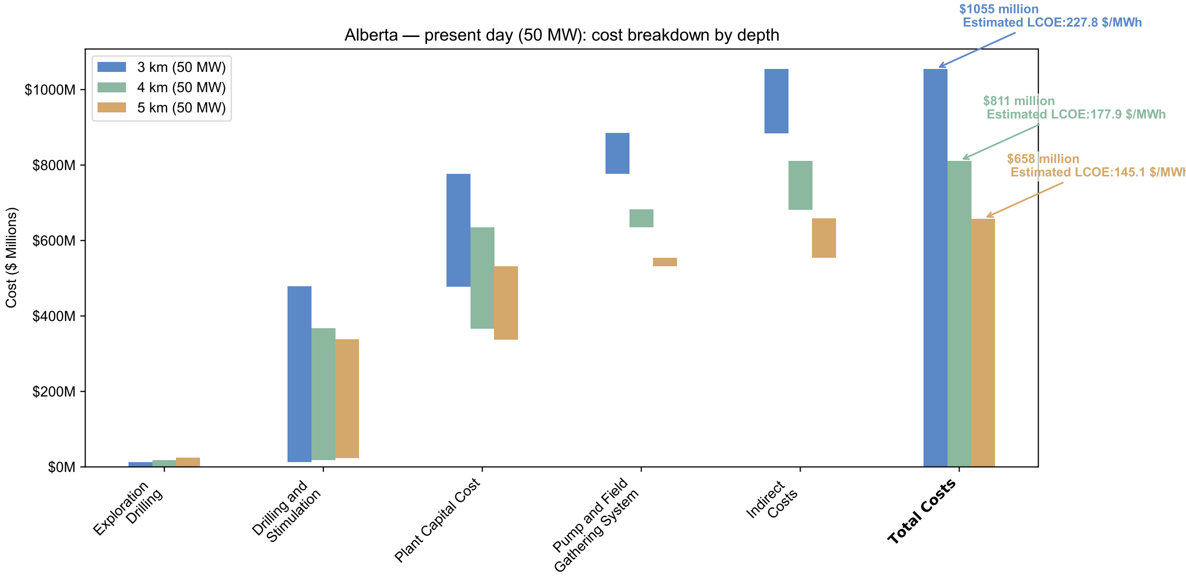
The composition of capital expenditure for each of the present-day modelled scenarios is shown in Figures 5-8. In all cases, power plant capital costs are the dominant expense at a reservoir depth of 3 km. However, at greater depths, drilling and stimulation costs become comparable to or exceed plant capital costs.

Interestingly, total drilling costs generally decrease with depth, which may seem counterintuitive. While the cost of drilling increases on a per-well basis as depth increases, the number of wells required to achieve the modelled plant capacity decreases due to higher reservoir temperatures at greater depths, which enhance power output per well.

An exception to this trend occurs when the model shifts from a binary to a flash power plant at greater depths (i.e., when the temperature exceeds 200°C). The model assumes that wells in a flash plant have lower flow rates than those in a binary plant. As a result, even though higher temperatures improve power conversion efficiency, the required number of wells assumed in the model does not decrease commensurately due to each well's lower flow rates. Consequently, total drilling costs can increase with depth rather than decrease. This effect is evident when comparing the present-day scenario models at 3 km and 4 km in British Columbia, and 4 km and 5 km in the Northwest Territories, as shown in Figures 6 and 7, respectively.

FIGURE 5.

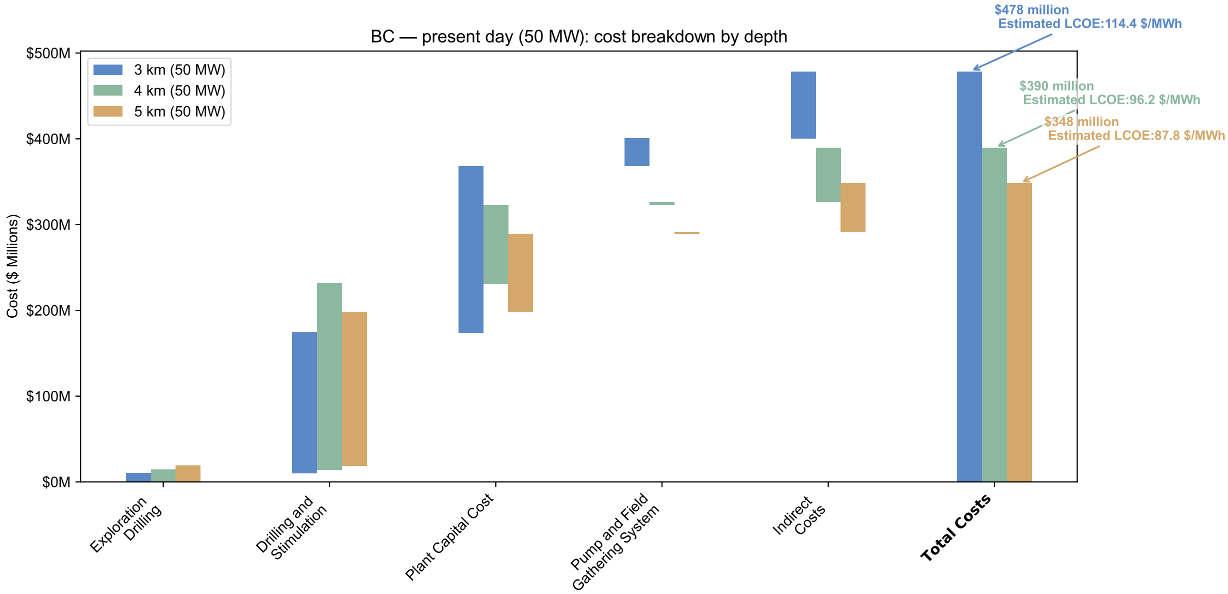
Capital costs for an EGS project at different depths in Alberta under the present-day (50 MW) modelled scenario



Key drivers in project costs are drilling and stimulation costs—the 3 km geothermal resource depth scenario requires an estimated 16 production wells and 16 injection wells to achieve net power generation of 50 MW. Conversely, for the higher-temperature 4 km depth scenario, nine production wells and eight injection wells are needed to achieve 50 MW of generation. Even though deeper wells are more expensive to drill than shallower wells, harnessing a higher-temperature resource means that fewer wells are needed to achieve the desired output, and the project's overall drilling costs decrease relative to an electricity generation project targeting a 3 km resource with less efficient conversion between thermal power and electrical power. All costs in U.S. dollars.

FIGURE 6.

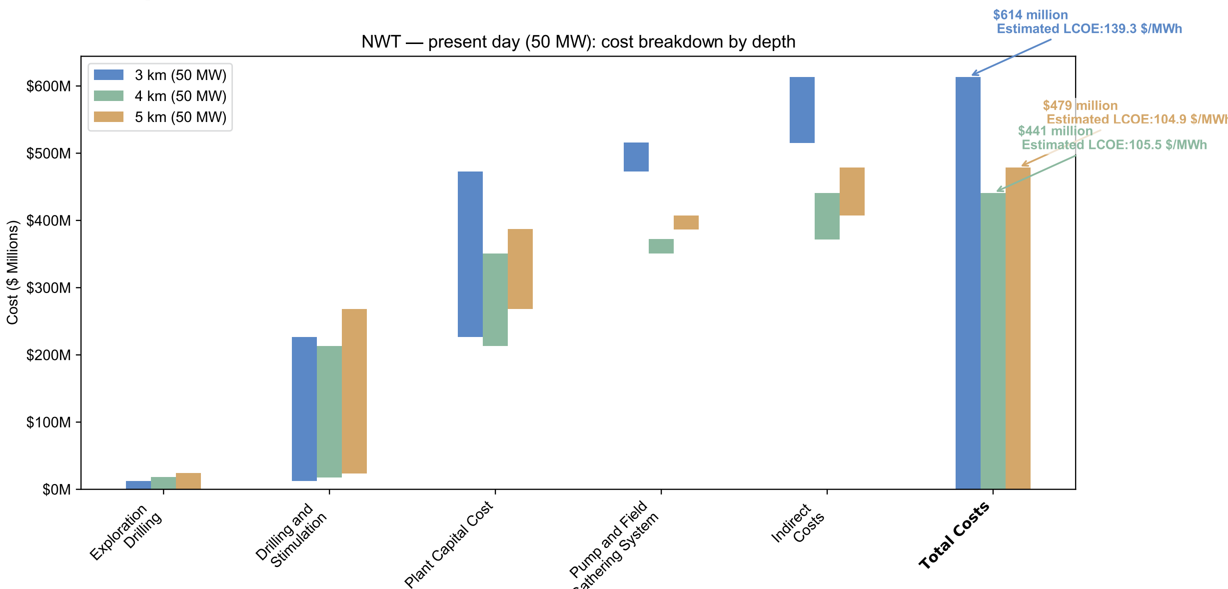
Capital costs for an EGS project at different depths in British Columbia under the present-day (50 MW) modelled scenario.



With the higher geothermal gradient (54°C/km) in the British Columbia scenario, a 3 km geothermal project has an estimated resource temperature of 162°C and 12 wells (six injectors and six producers), which are estimated to deliver a net power output of 50 MW. A 5 km project is estimated to need seven wells (three injectors and four producers) to deliver net power of 50 MW. As a result, the drilling and stimulation expense for a 3 km project and a 5 km project are roughly equal (~$165M and $179M respectively). Major drivers for changes in modelled LCOE are the higher plant capital expenses associated with a 3-km-deep project compared to the 4- or 5-km-deep projects. All costs in U.S. dollars.

FIGURE 7.

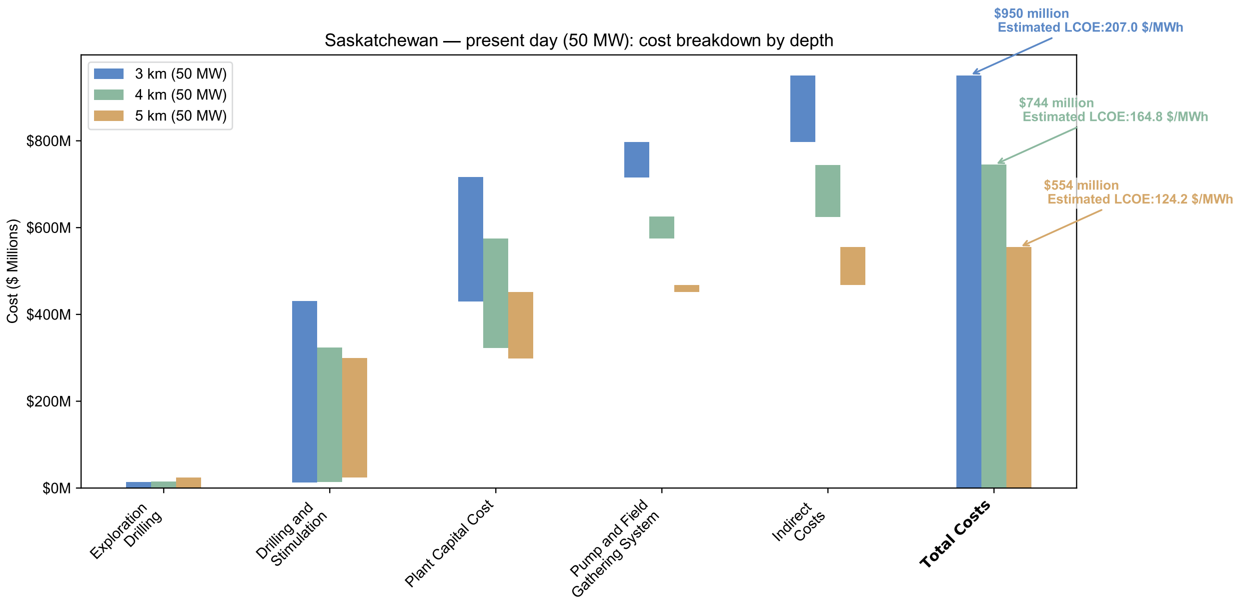
Capital costs for an EGS project at different depths in the Northwest Territories under the present-day (50 MW) modelled scenario.



Slightly higher drilling and stimulation costs for a project targeting a depth of 5 km and 225°C compared to a project targeting a 4 km depth and 180°C are offset by lower plant capital costs. Hence, both projects have very similar total capital spend and estimated LCOE. All costs in U.S. dollars.

FIGURE 8

Capital costs for an EGS project at different depths in Saskatchewan under the present-day (50 MW) modelled scenario.



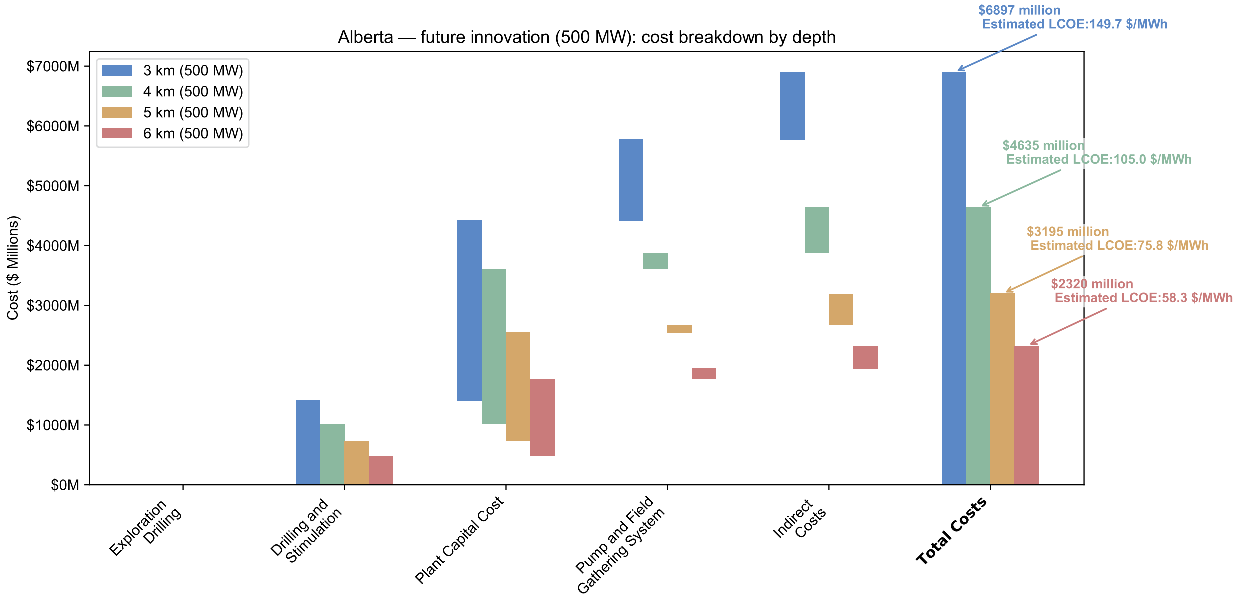
Similar to the modelled results for Alberta, a 3 km geothermal resource depth scenario requires an estimated 14 production wells and 14 injection wells to achieve net power generation of 50 MW. Conversely, for the higher-temperature 4-km-depth scenario, eight production wells and seven injection wells are needed to achieve 50 MW of generation. All costs in U.S. dollars.

Future innovation scenarios

The composition of capital expenditure for each of the modelled future innovation scenarios is shown in Figures 9-12. In all cases, power plant capital costs and drilling and stimulation costs are the dominant expense.

FIGURE 9

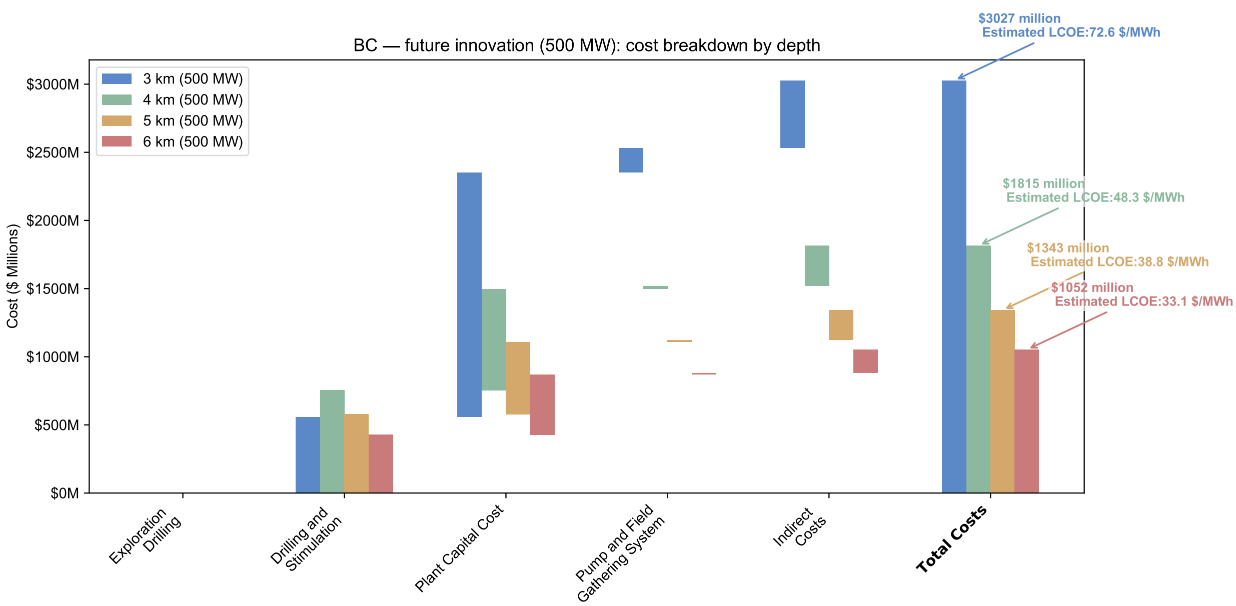
Capital costs for an EGS project at different depths in Alberta under the future innovation (500 MW) modelled scenario



In the future innovation scenarios, reduced drilling costs lead to capital associated with power plant construction becoming the single biggest expense category. All costs in U.S. dollars.

FIGURE 10

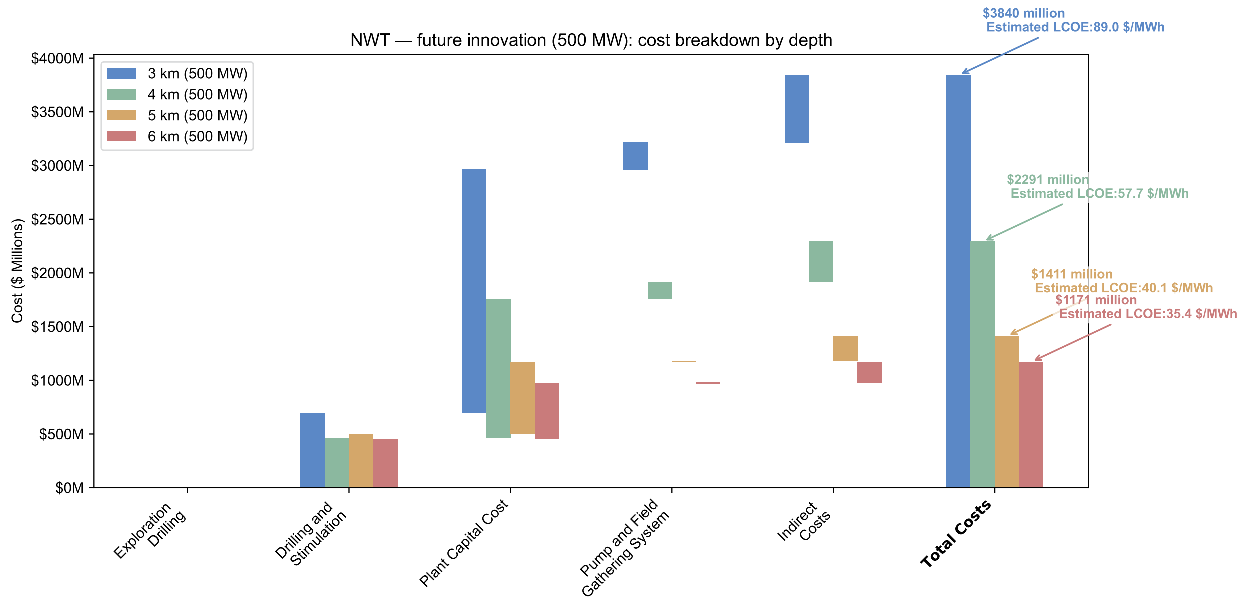
Capital costs for an EGS project at different depths in British Columbia under the future innovation (500 MW) modelled scenario



All costs in U.S. dollars.

FIGURE 11

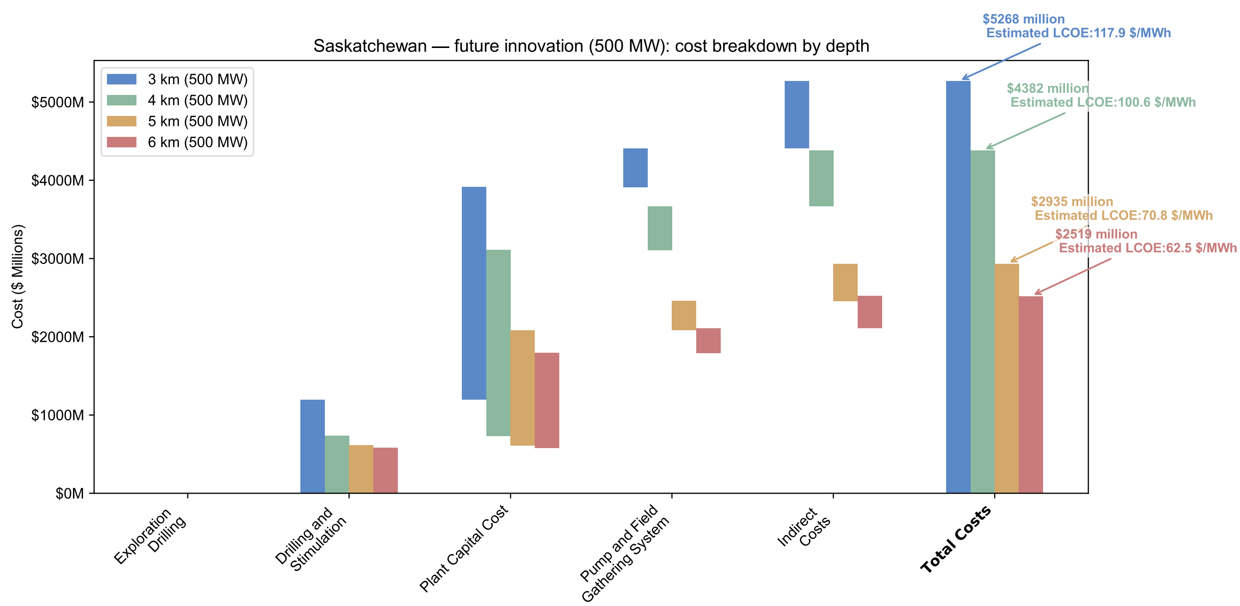
Capital costs for an EGS project at different depths in the Northwest Territories under the future innovation (500 MW) modelled scenario



All costs in U.S. dollars.

FIGURE 12.

Capital costs for an EGS project at different depths in Saskatchewan under the future innovation (500 MW) modelled scenario



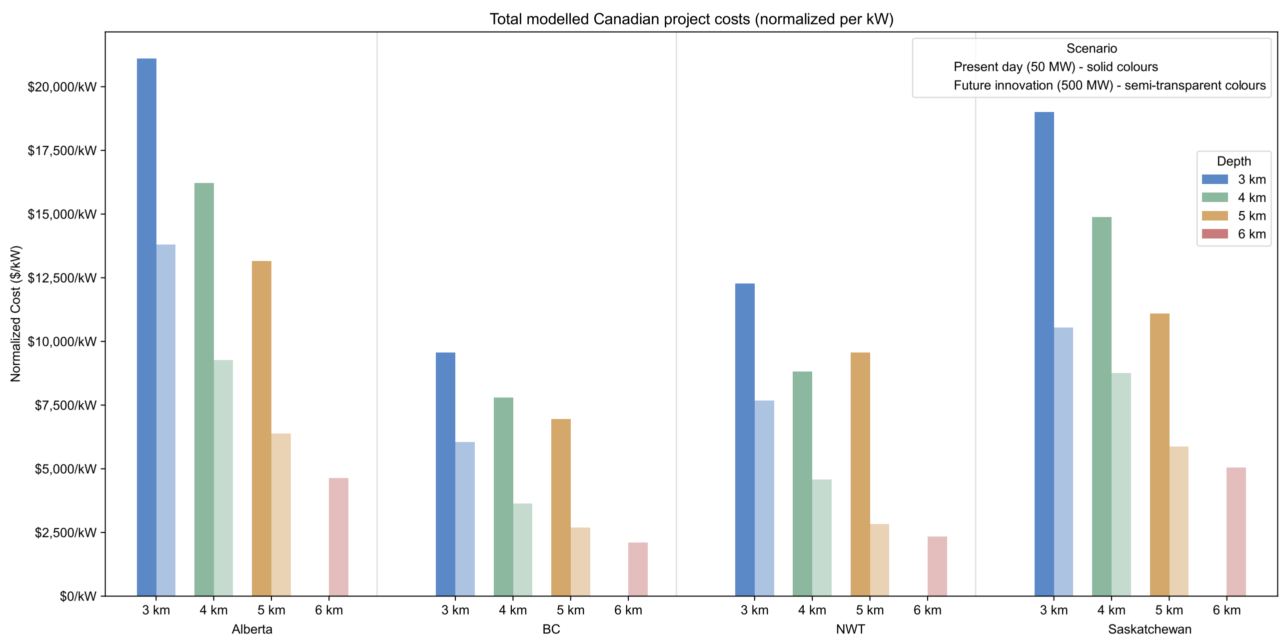
All costs in U.S. dollars.

Comparison: Present-day and future innovation scenarios

A comparison of total capital costs per kW of power generated between the present-day and future innovation scenarios is shown in Figure 13. In all cases, the normalized capital expenditure (US$/kW) declines significantly in the future innovation scenario.

FIGURE 13.

Total estimated costs expressed as US$/kW at different depths for present-day (solid colors) and future innovation (semi-transparent) scenarios for each province



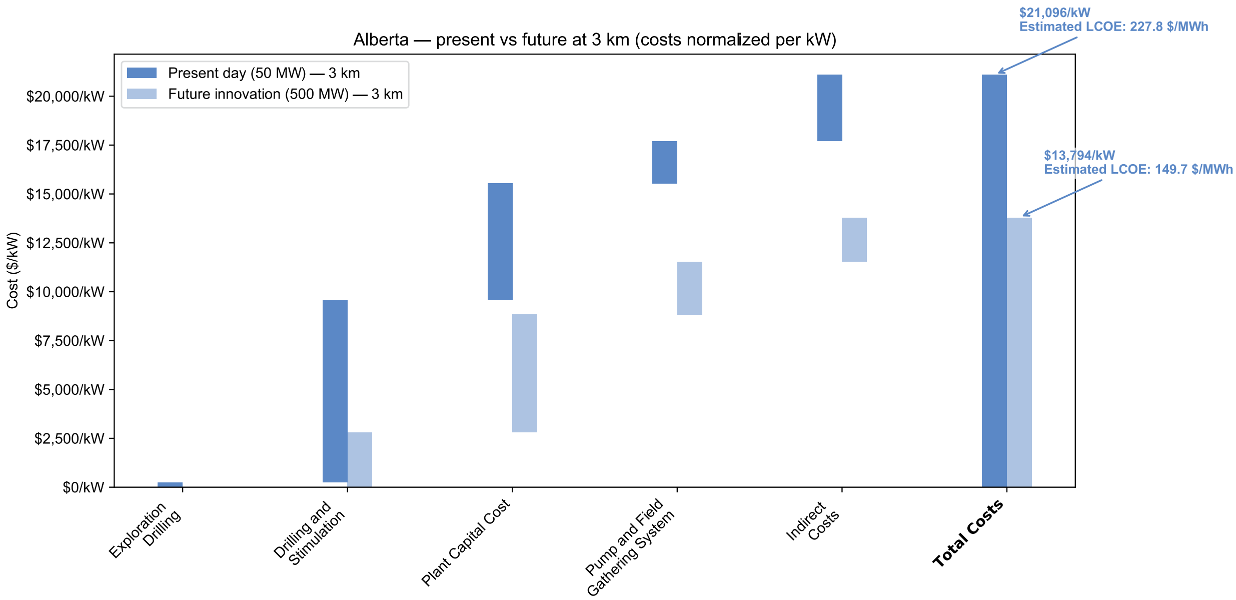
The composition of capital costs for the future innovation scenario relative to the present-day scenario across all case studies is shown in Figures 14-23. A similar trend in drilling and stimulation costs is observed in the future innovation scenario as in the present-day scenario. However, due to assumed improvements in drilling technologies and the resulting decrease in well costs, plant capital costs become the dominant expense in all future innovation models as drilling and stimulation costs fall.

Alberta

The comparison between the present-day and future innovation scenarios (normalized in US$/kW terms to facilitate direct comparison between the 50 MW present-day and 500 MW future innovation projects) for Alberta are shown below in Figures 14-17.

FIGURE 14

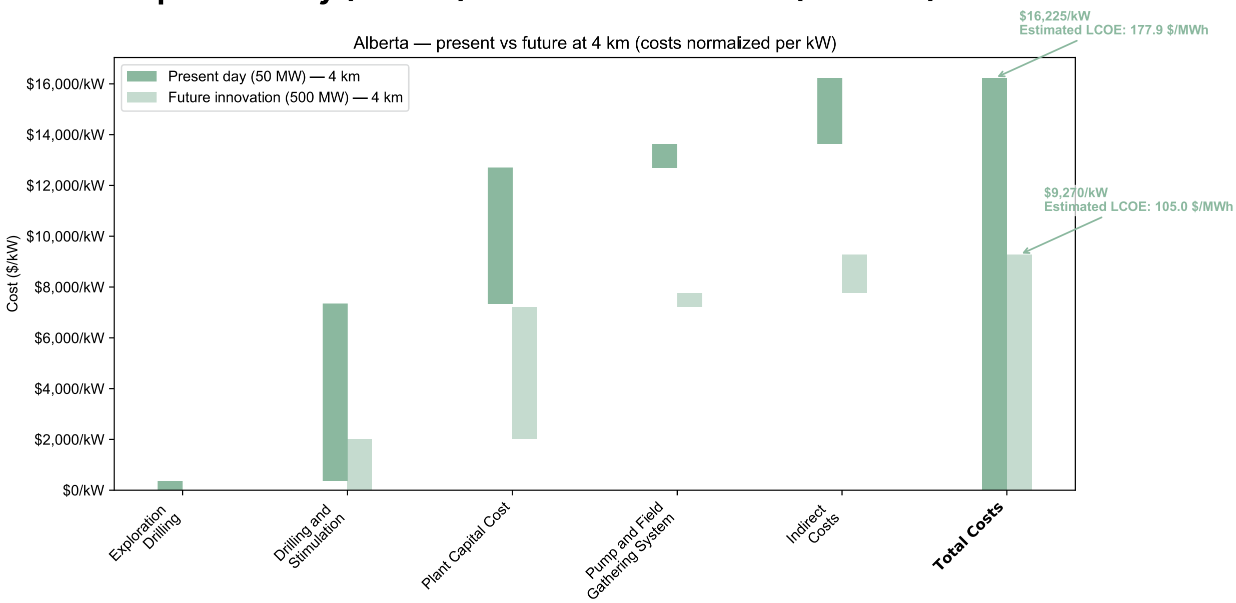
Capital costs for an EGS project at a 3 km depth (93°C resource temperature) in Alberta for present-day (50 MW) and future innovation (500 MW) modelled scenarios



Costs are expressed in US$/kW for comparative purposes.

FIGURE 15

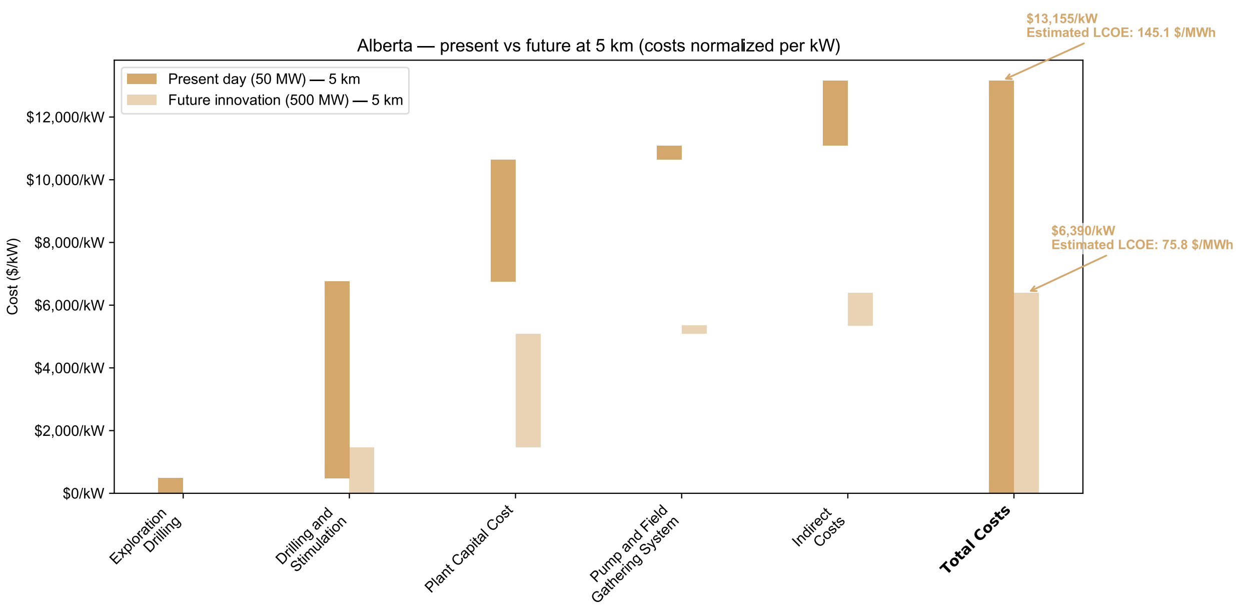
Capital costs for an EGS project at a 4 km depth (124°C resource temperature) in Alberta for present-day (50 MW) and future innovation (500 MW) modelled scenarios.



Costs are expressed in US$/kW for comparative purposes.

FIGURE 16

Capital costs for an EGS project at a 5-km depth (155°C resource temperature) in Alberta for present-day (50 MW) and future innovation (500 MW) modelled scenarios.



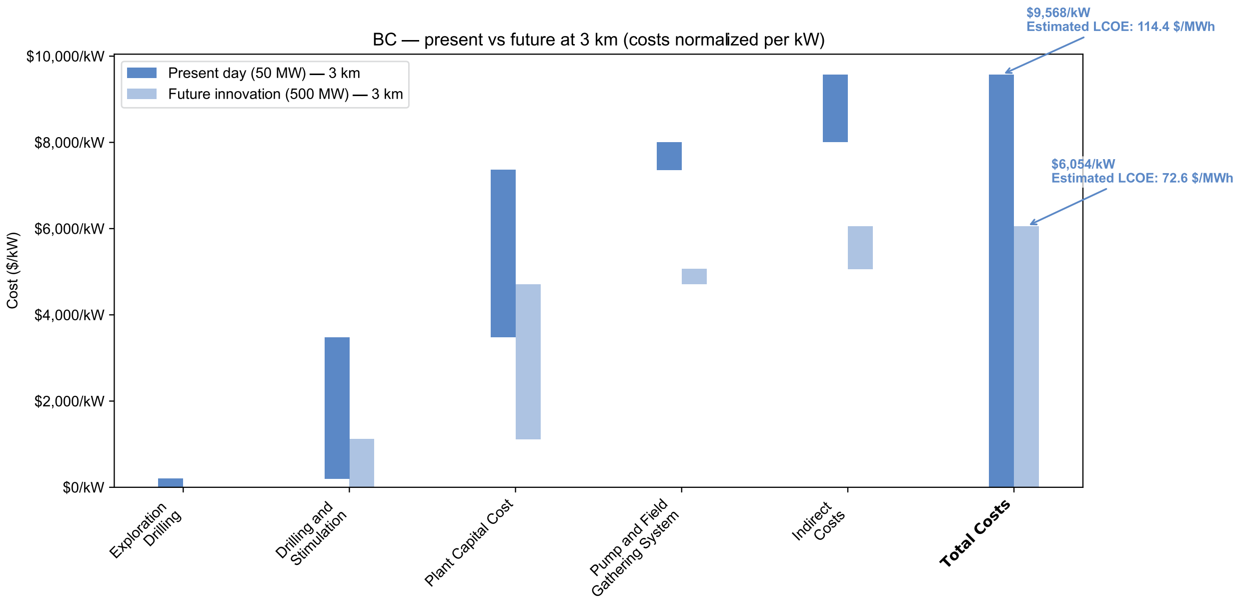
Costs are expressed in US$/kW for comparative purposes.

British Columbia

The comparison between the present-day and future innovation scenarios (normalized in US$/kW terms to facilitate direct comparison between the 50 MW present-day and 500 MW future innovation projects) for British Columbia are shown below in Figures 17-19.

FIGURE 17

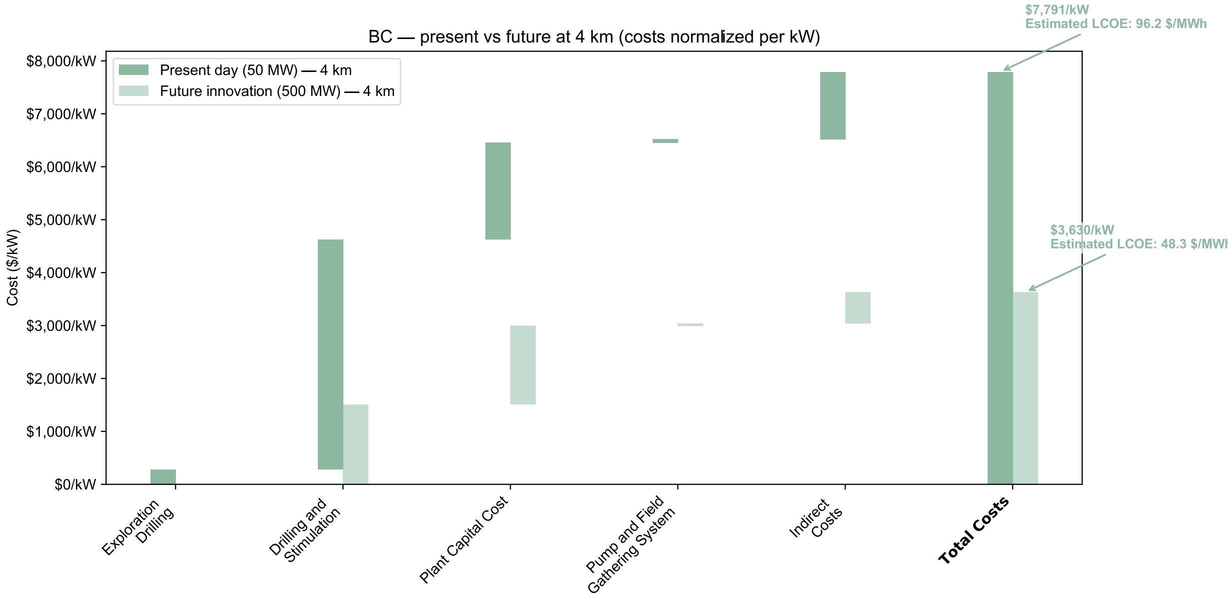
Capital costs for an EGS project at a 3 km depth (162°C resource temperature) in Alberta for present-day (50 MW) and future innovation (500 MW) modelled scenarios.



Costs are expressed in US$/kW for comparative purposes.

FIGURE 18

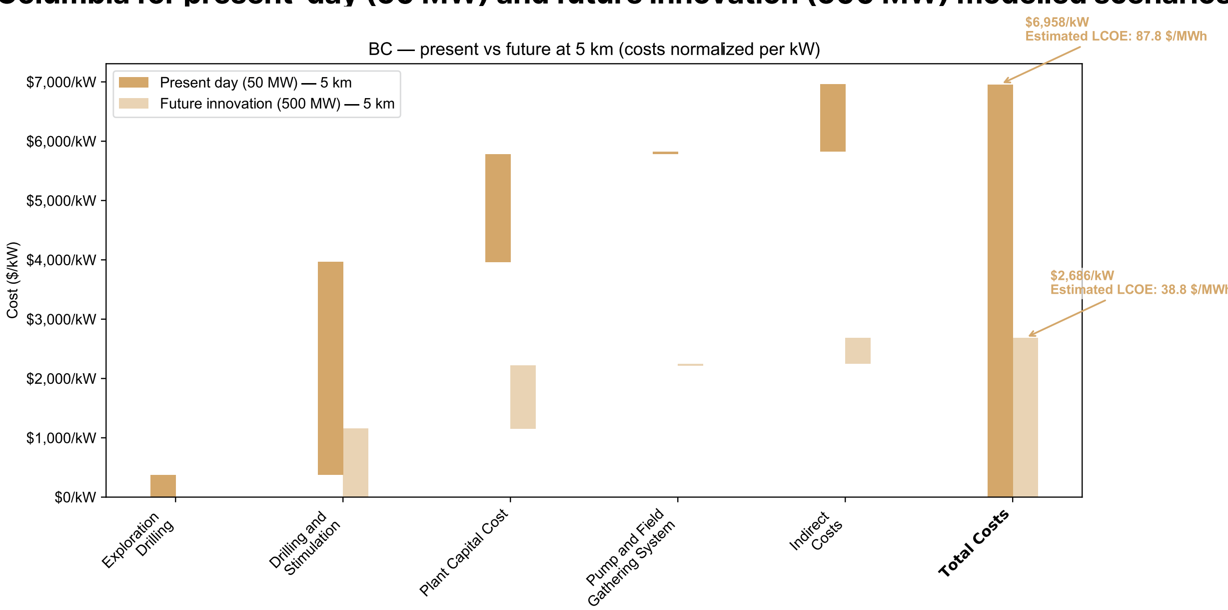
Capital costs for an EGS project at a 4 km depth (216°C resource temperature) in British Columbia for present-day (50 MW) and future innovation (500 MW) modelled scenarios



Costs are expressed in US$/kW for comparative purposes.

FIGURE 19

Capital costs for an EGS project at a 5 km depth (270°C resource temperature) in British Columbia for present-day (50 MW) and future innovation (500 MW) modelled scenarios.



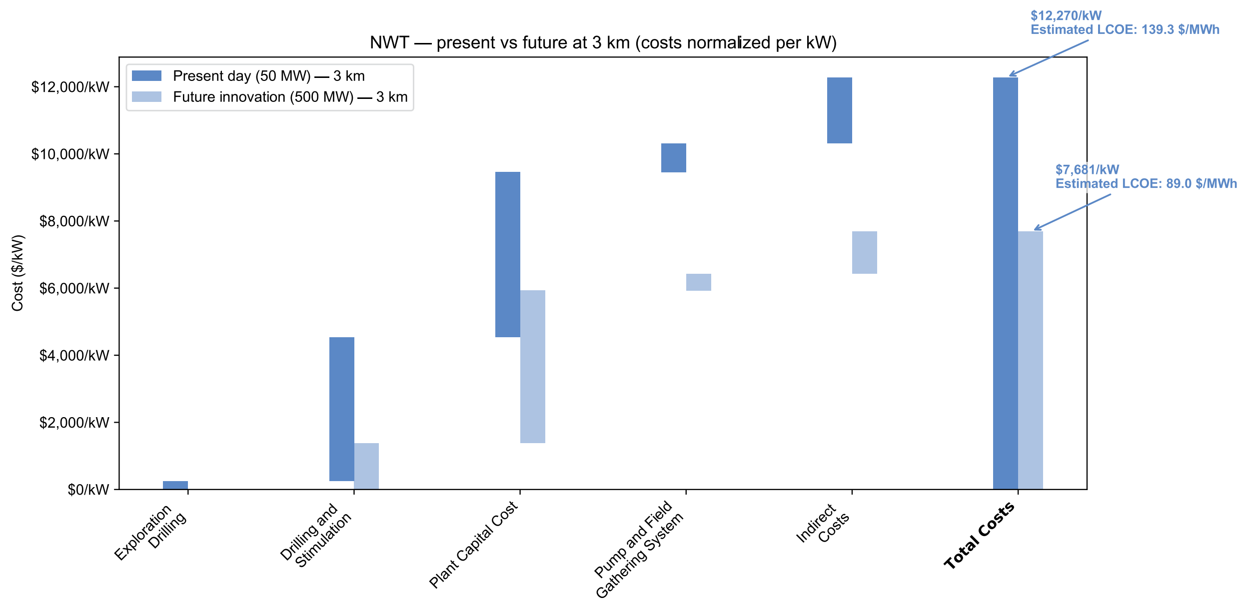
Costs are expressed in US$/kW for comparative purposes.

Northwest Territories

The comparison between the present-day and future innovation scenarios (expressed in US$/kW to facilitate direct comparison between the 50 MW present-day and 500 MW future innovation projects) for the Northwest Territories are shown below in Figures 20-22.

FIGURE 20

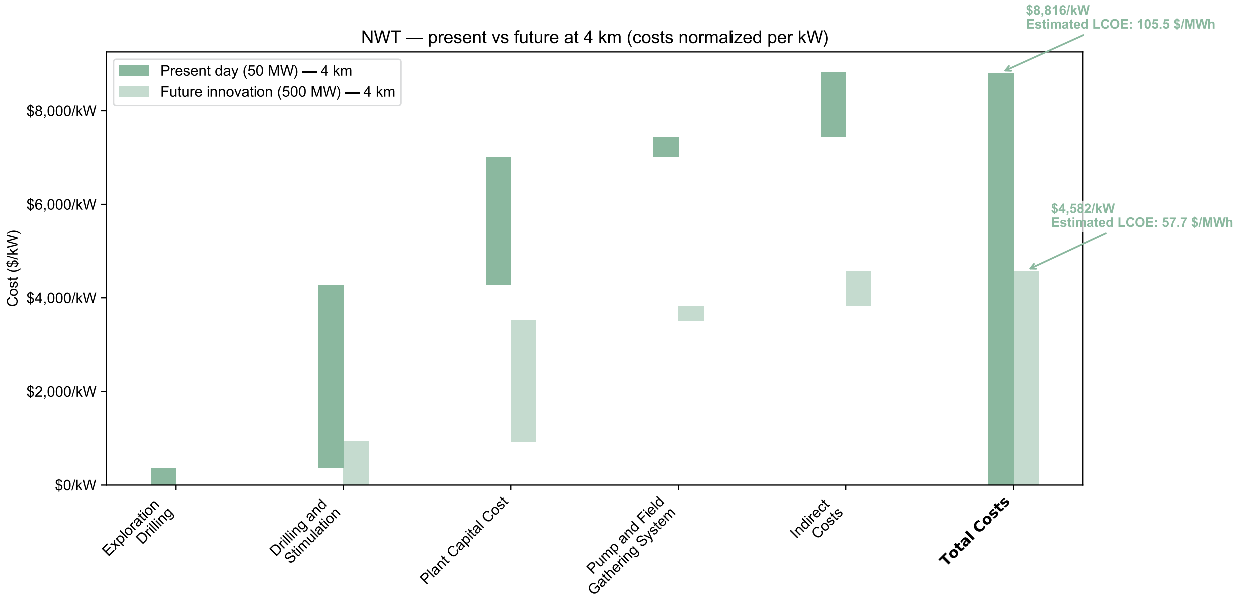
Capital costs for an EGS project at a 3 km depth (135°C resource temperature) in the Northwest Territories for present-day (50 MW) and future innovation (500 MW) modelled scenarios



Costs are expressed in US$/kW for comparative purposes.

FIGURE 21

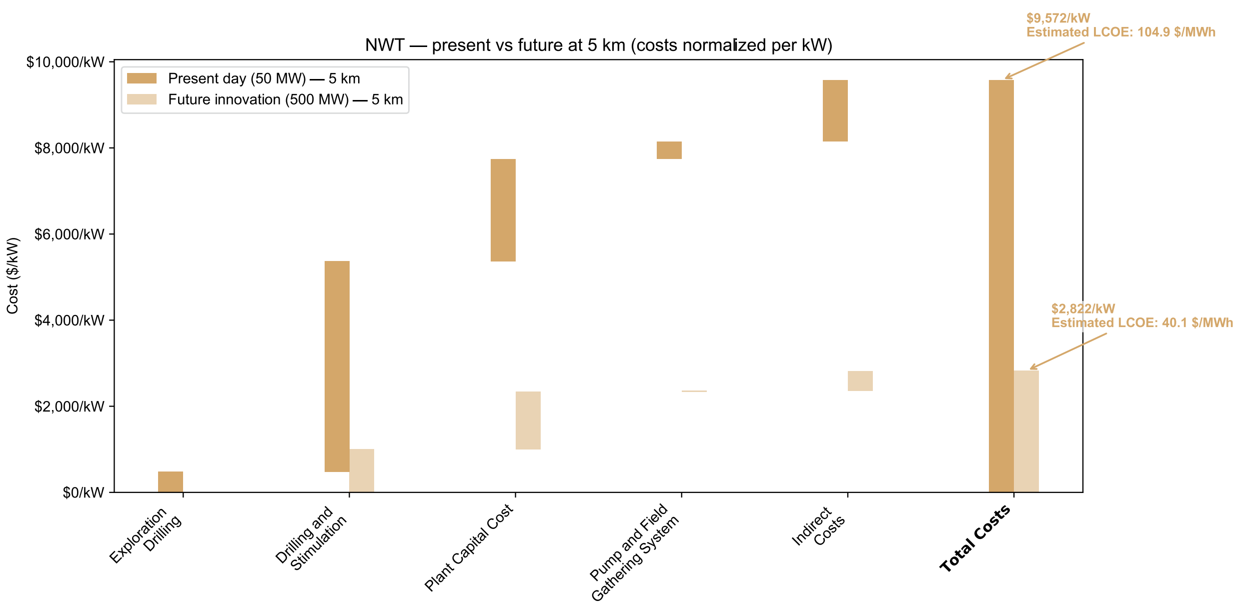
Capital costs for an EGS project at a 4 km depth (180°C resource temperature) in the Northwest Territories for present-day (50 MW) and future innovation (500 MW) modelled scenarios



Costs are expressed in US$/kW for comparative purposes.

FIGURE 22

Capital costs for an EGS project at a 5 km depth (225°C resource temperature) in the Northwest Territories for present-day (50 MW) and future innovation (500 MW) modelled scenarios



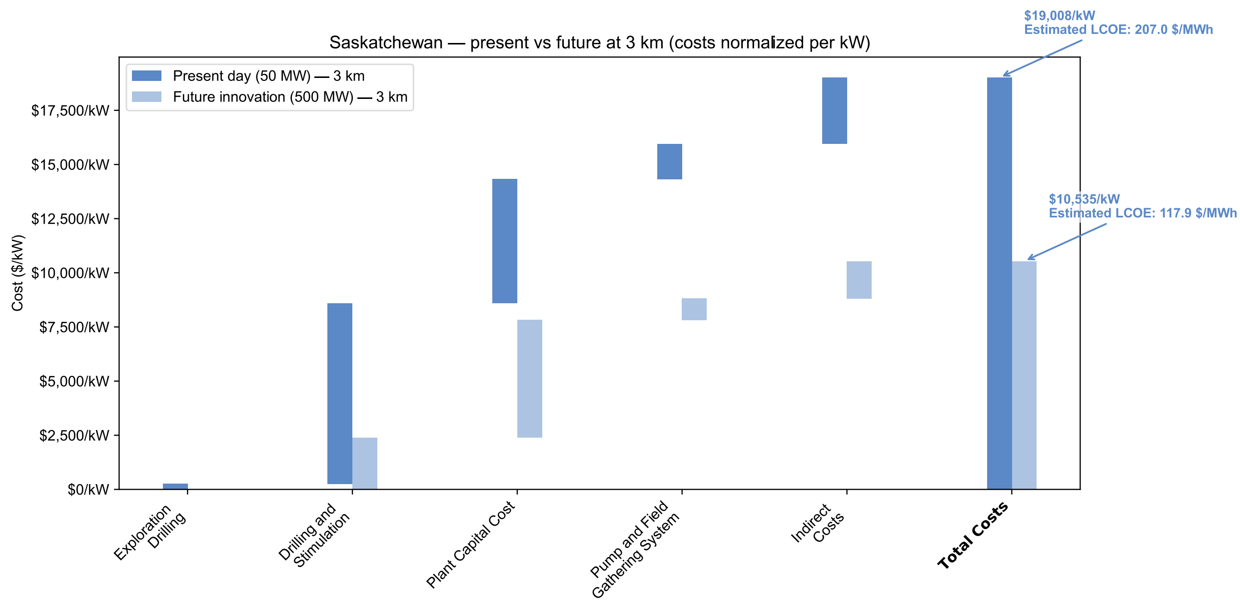
Costs are expressed in US$/kW for comparative purposes.

Saskatchewan

The comparison between the present-day and future innovation scenarios (normalized in US$/kW terms to facilitate direct comparison between the 50 MW present-day and 500 MW future innovation projects) for Saskatchewan are shown below in Figures 23-25.

FIGURE 23

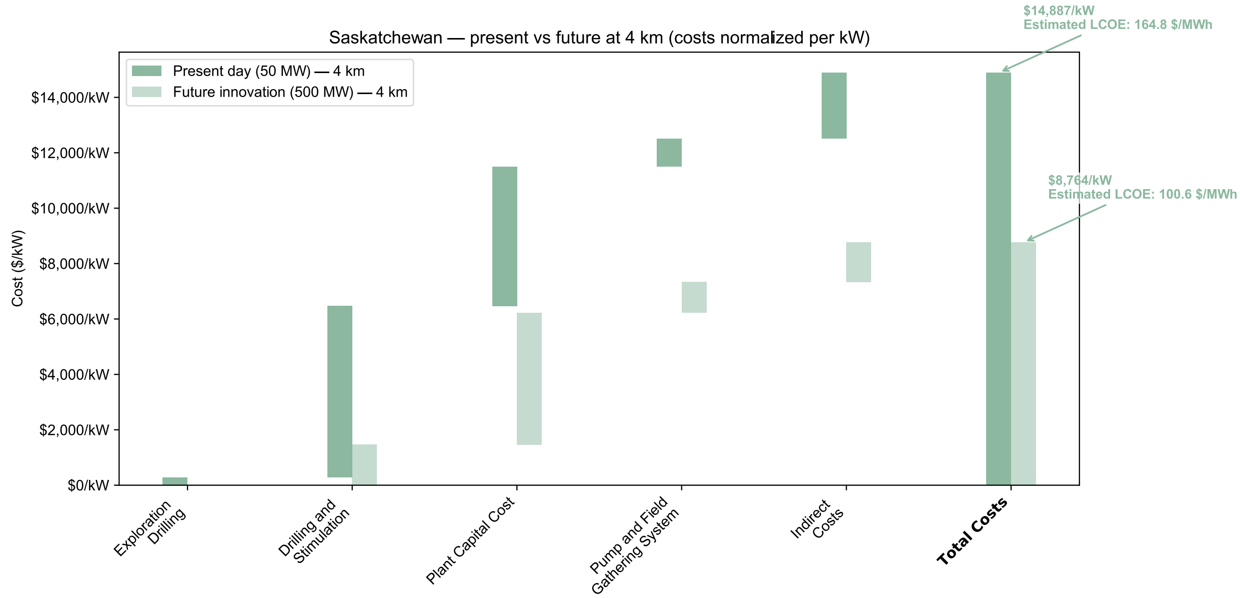
Capital costs for an EGS project at a 3 km depth (105°C resource temperature) in Saskatchewan for present-day (50 MW) and future innovation (500 MW) modelled scenarios



Costs are expressed in US$/kW for comparative purposes.

FIGURE 24

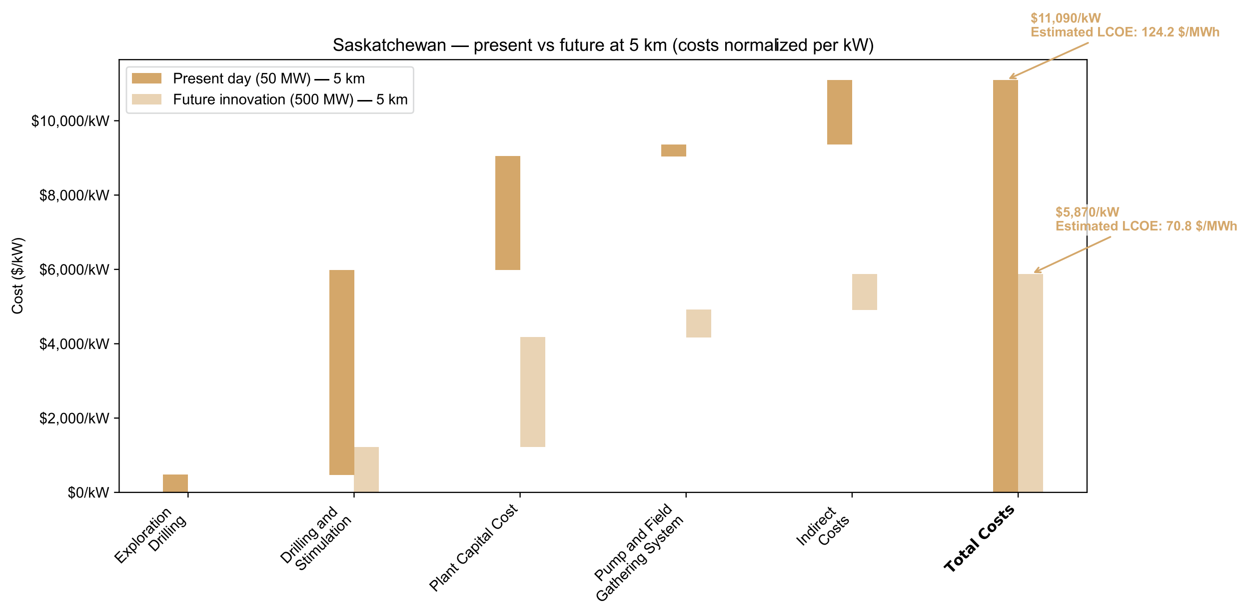
Capital costs for an EGS project at a 4 km depth (140°C resource temperature) in Saskatchewan for present-day (50 MW) and future innovation (500 MW) modelled scenarios



Costs are expressed in US$/kW for comparative purposes.

FIGURE 25

Capital costs for an EGS project at a 5 km depth (175°C resource temperature) in Saskatchewan for present-day (50 MW) and future innovation (500 MW) modelled scenarios



Costs are expressed in US$/kW for comparative purposes.

4. Discussion

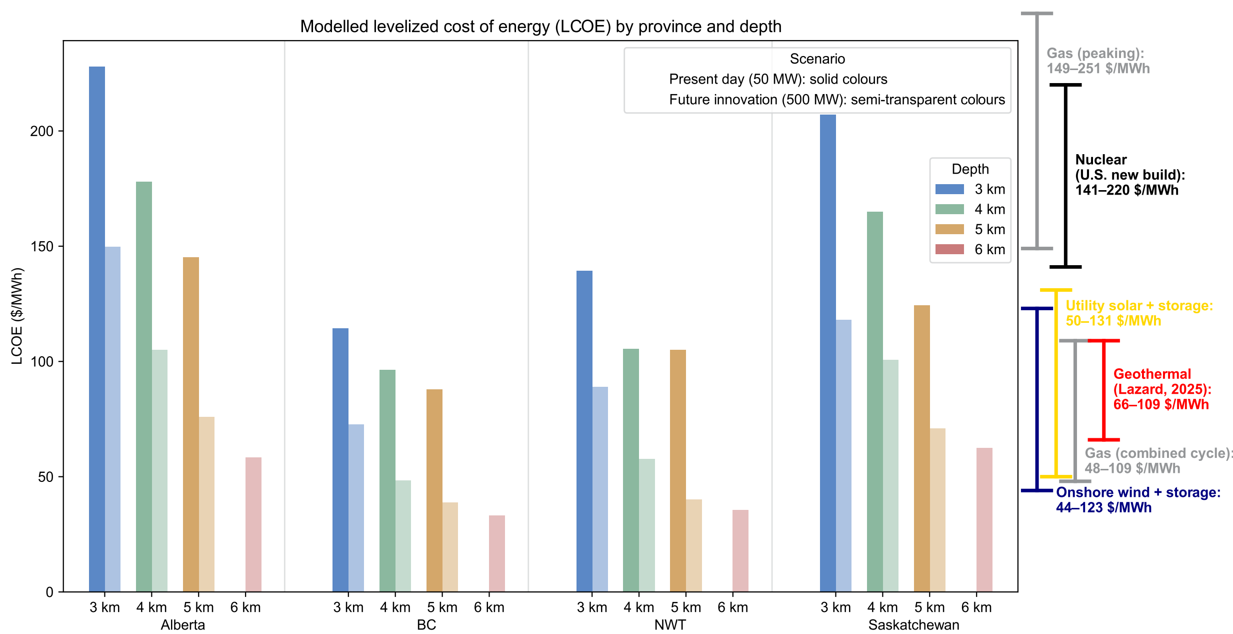
This analysis finds that LCOE estimates for EGS in western and northwestern Canada are already competitive with other options for baseload electricity generation, especially in areas with hotter geothermal gradients such as the Northwest Territories and British Columbia. Saskatchewan and Alberta, with cooler modelled geothermal gradients, have higher estimated LCOE values, principally due to cooler subsurface temperatures. Such conditions require more producer-injector well pairs and higher power plant capital costs to handle the higher total system flow rate at lower temperatures to achieve the target power output.

Although most of the LCOE estimates for the present-day scenarios are greater than $100/MWh, technological advancements have the potential to significantly improve the cost competitiveness of EGS for electricity generation. As shown above in Figure 4 and Table 3 and below in Figure 26, anticipated LCOE reductions of 40-50% in the future innovation scenario strongly justify continued investment in technological improvements, particularly in drilling, stimulation, and well field optimization. Innovation in these areas presents high-leverage opportunities to scale EGS development in ways that would also drive efficiencies and cost reductions in conventional energy and conventional geothermal development.

EGS comparison with other technologies

FIGURE 26

LCOE (US$/MWh) for EGS projects at varying depths for present-day and future innovation scenarios



For comparison, the range of LCOE for other forms of baseload or dispatchable generation (gas generation (peaking and combined cycle), new-build nuclear, utility solar with storage, onshore wind with storage, and geothermal) published by Lazard (2025) are shown as range bars on the right-hand side of the plot.

With the anticipated cost declines that continued innovation will drive, EGS compares very favourably with other non-emitting sources of electricity such as utility-scale wind generation with storage, and utility-scale solar with storage. It also, crucially, compares favourably with other sources of baseload electricity, such as nuclear and even combined cycle gas, even in parts of western and northwestern Canada with relatively cool geothermal gradients. We also note that if recent price increases and supply chain delays for natural gas turbines linger in the global market, fuel costs increase, or the cost of carbon emissions on industrial emitters continues to escalate, the case for EGS is even stronger (Shenk, 2025).

This economic modelling by Cascade Institute also aligns with the LCOE range for geothermal energy as reported by Lazard (2025) in their tracking of current market trends. We note that Lazard's reported LCOE range is slightly lower than the range of our modelled values due to current EGS development in the market targeting locations with hotter geothermal gradients than those modelled in this exercise.

It should also be noted that the value of firming electrical system capacity with either dispatchable generation or >4-hour storage increases with the amount of intermittent generation that comes online. Lazard outlines the need for a diverse generation portfolio that includes geothermal, long-duration storage, nuclear SMRs, pumped hydro, or other sources of generation that provides the reliability backbone required for the low-carbon electricity systems of tomorrow.

Key areas for innovation

1. **Advancements in drilling and completion technologies**
   Drilling costs remain one of the largest contributors to overall project expenses, particularly at greater depths. This analysis demonstrates that lower drilling costs provide access to deeper, hotter reservoirs, with efficiency improvements reducing power plant capital costs. Technologies such as advanced directional drilling, improved bit materials, automation, and real-time drilling optimization can further lower costs and improve success rates (Pearce & Pink, 2024). The future innovation scenario assumes a significant reduction in drilling costs, in line with recent industry advancements by companies like Fervo Energy and the Utah FORGE research site, suggesting that continued innovation in this area is a critical driver of further cost declines for EGS.

2. **Reservoir stimulation and flow enhancement**
   These results also indicate that improvements to reservoir injectivity and productivity are key to reducing the number of wells required per unit of power generation, thereby lowering overall project costs. The future innovation scenario incorporates improved stimulation success rates, reflecting advancements in multistage hydraulic fracturing and proppant-based stimulation techniques that have been successfully applied in recent pilot projects. Continued development of these technologies will be essential for Canada to unlock the full potential of EGS.

3. **Optimized power plant design and reduced pumping requirements**
   The economic feasibility of EGS is not only dependent on resource availability but also on efficient energy conversion. This analysis shows that with higher reservoir temperatures, capital costs decrease for binary ORC turbines. This finding aligns with the understanding that conversion efficiency increases with temperature (Figure 2). While the shift from binary to flash power plants at >200°C added some complexity to the modelling, higher reservoir temperatures that utilize flash plants are more cost-effective, as long as flash plants can effectively manage potential site-specific geochemical issues such as scaling and corrosion.

   Further research is needed to refine plant design and well-field configurations to minimize pumping costs and enhance overall system efficiency. Additionally, improvements in submersible pump technology and reduced parasitic power loads will further enhance project economics.

4. **High-temperature materials and tools**
   Advanced materials can withstand intense heat, pressure, and corrosive fluids, enabling deeper drilling, higher efficiency, and longer plant lifespans. Investing in this research unlocks superhot rock resources and reduces maintenance costs, thereby expanding geothermal power's role as a reliable, baseload clean energy source. Because power output rises quickly with temperature, high-temperature materials and tools are needed to increase power output and decrease costs.

The role of lower drilling costs in accessing deeper and hotter reservoirs

A key finding from this study is that LCOE consistently falls with depth, primarily due to the improved efficiency of power generation at higher temperatures. While deeper wells have higher individual drilling costs, the reduction in the number of wells required to meet plant capacity leads to lower total drilling costs. This effect is particularly pronounced in the future innovation scenario, where drilling advancements allow for cost-effective access to deeper, hotter resources. Additionally, higher resource temperatures enhance plant efficiency, further reducing plant capital costs. Therefore, expanding access to high-temperature reservoirs is the key to increasing plant efficiency and reducing overall project costs.

> *LCOE consistently falls with depth, primarily due to the improved efficiency of power generation at higher temperatures.*

Confidence in modelled results

Across all present-day scenario modelled results, the GETEM model ran successfully without requiring workarounds at 3 km and 4 km depths. This suggests that within these depth ranges, the model's assumptions and cost calculations remain internally consistent. However, at 3 km depth for lower-gradient sites (Alberta and Saskatchewan), the modelled plant capital costs appear disproportionately high, with modelled power plant costs exceeding $7,000/kW for these scenarios. While we expect binary plant costs to increase significantly at lower resource temperatures due to reduced power cycle efficiency and increased fluid flow requirements, the magnitude of the cost increase at 3 km vs 4 km in Alberta and Saskatchewan did not appear reasonable when compared with industry data for low-temperature binary Organic Rankine Cycle (ORC) turbines. For this reason, we manually capped costs in these scenarios at $5,000/kW.

In the future innovation scenario, most models for the Northwest Territories required workarounds. It is unclear why the Northwest Territories was disproportionately affected, but it may be related to a trade-off between temperature and depth affecting pumping requirements. As a result, we consider the Northwest Territories' models the least reliable across all four locations. Similarly, for Alberta, the 6 km future innovation scenario required a particularly high flow rate to resolve a model error, reducing confidence in that result, although the model runs for the other depths (except for the above-noted 3 km scenario) ran reliably and repeatably.

Among all the provinces, British Columbia produced the most reliable modelled results, with only a single minor workaround required in one case across both the present-day and future innovation scenarios.

Limitations and future work

While this study provides valuable insights into the techno-economic feasibility of EGS in western and northwestern Canada, it has several limitations that can and should guide future work.

Site-specific constraints and data gaps

This analysis is based on high-level scenarios using the expected thermal gradient within a region, drilling cost curves, and assumed productivity parameters. However, site-specific factors such as subsurface stress conditions, fracture networks, and fluid chemistry are not explicitly modelled. These geological uncertainties could significantly influence reservoir performance and long-term well productivity. Future studies should incorporate detailed reservoir characterization, geomechanical modelling, and hydrothermal simulations to better constrain project viability at specific sites.

Long-term reservoir performance and sustainability

The longevity and sustainability of EGS reservoirs are uncertain due to:

- the rate of thermal drawdown over decades of operation;
- permeability evolution and potential reductions in injectivity/productivity over time; and
- the need for periodic reservoir restimulation and associated costs.

Future site-specific work should explore time-dependent reservoir behaviour using coupled thermal-hydraulic-mechanical models to predict how permeability and temperature evolve over the project lifespan.

Optimization of well-field design

This study did not take into account how well spacing, well length, and injection-to-production well ratios can influence pressure balance and pumping requirements. Future research should investigate:

- the impact of longer laterals on fluid circulation and heat extraction from a larger volume of high-temperature rock;
- optimal spacing configurations to minimize thermal breakthrough; and
- alternative well configurations (e.g., multi-lateral or triplet designs) to improve flow efficiency.

Optimization could reduce parasitic pumping loads, ultimately lowering operational costs and improving the LCOE. In fact, Fervo Energy has already increased projected power output from 400 MW to 500 MW from the same number of wells, due to such optimization.

Model limitations and potential refinements

Several technical limitations in the GETEM model affected the analysis, including:

- inability to model temperature losses in production wells due to a software error;
- issues with pumping calculations, leading to manual workarounds for production and injection pump costs; and
- constraints in built-in optimization tools, such as the Geothermal Plant Efficiency Optimizer for binary plants.

Future work should refine cost and efficiency estimates. This could be done by either updating some of GETEM's assumptions in future versions of SAM or integrating alternative modelling approaches using tools with updated reservoir modelling capabilities, such as the Geophires tool developed by NREL. Such future work could also integrate representative geothermal pressure and fracture models from platforms such as the Geothermal Design Tool (GeoDT), developed by the Los Alamos National

Laboratory, or the TOUGH3 numerical simulation program, developed by the Lawrence Berkeley National Laboratory.

Policy and economic considerations

While this study focuses on technical cost drivers, broader economic factors such as government incentives, carbon pricing, and market conditions will also influence EGS competitiveness. Future research should evaluate:

- the impact of carbon credits and renewable energy incentives on LCOE;
- grid integration challenges for high-capacity EGS projects (e.g., 500 MW facilities); and
- financing models and risk reduction strategies for EGS development in Canada.

Comparative analysis with other energy technologies

To better position EGS within Canada's energy mix, future studies should:

- complete energy system modelling in western and northwestern Canada to estimate future deployment potential of EGS;
- assess synergies with oil and gas infrastructure (e.g., repurposing existing well pads as drilling locations or geophysical data sets to support EGS development);
- analyze the role that AGS closed-loop geothermal could play as a source of renewable baseload energy; and
- investigate the role of hybrid or dual-purpose geothermal systems (e.g., geothermal electricity plus cogenerated direct-use heat).

5. Conclusion

This techno-economic analysis highlights the opportunity and potential for EGS to provide clean, affordable, and secure baseload power in western and northwestern Canada. Indeed, we find that EGS is already cost-competitive with other baseload electricity generation technologies, especially in the Northwest Territories and British Columbia. With continued innovation, further reductions to estimated LCOE in the range of 40-50% are achievable, which would position EGS as among the lowest-cost firm power generation options.

Geothermal power proponents and governments can help make EGS a viable and competitive technology in Canada by addressing regulatory gaps (Smejkal et al., 2025) while pursuing research, development, and demonstration projects (Cascade Institute 2025) focused on reducing drilling costs, improving stimulation techniques, optimizing well-field design, and refining operational efficiencies. Geothermal power represents a promising technology that can support Canadian prosperity while advancing national progress toward a secure, clean, and affordable electricity system.

Appendix:

A detailed techno-economic analysis of enhanced geothermal systems

The following sections provide details on the many activities that constitute EGS project development: site characterization, exploration, well design and configuration, reservoir stimulation, pumps, and surface infrastructure.

Site characterization

Characterizing a potential EGS site is a critical step in determining its viability for development. Before drilling an exploration well, developers will conduct a combination of desktop studies and geophysical surveys to assess key geological, thermal, and hydrological factors. These investigations help target favourable locations with sufficient heat, depth, and rock conditions to support an engineered geothermal reservoir. A developer conducting a site characterization will generally assess the following factors:

1. **Heat resource assessment:** One of the primary factors in site selection is the availability of a sufficient heat resource. Heat is typically assessed through existing temperature gradient data and heat flow measurements, derived from existing boreholes, oil and gas wells, or regional geological studies. Higher thermal gradients indicate areas where deeper rock formations retain sufficient heat to generate electricity at the surface.
2. **Depth considerations:** The depth of economically viable temperatures is a key constraint in EGS feasibility. Shallower depths reduce drilling costs but may not provide sufficiently high temperatures for power generation. A balance between depth and achievable temperature must be established, typically targeting reservoirs at depths of 3-6 km, depending on regional heat flow conditions.
3. **Rock type and geomechanical properties:** The host rock must have suitable thermal and mechanical properties to sustain an artificial reservoir. Studies focus on identifying rock type, thermal conductivity, and mechanical strength, which influence heat transfer efficiency and the ability to create a permeable fracture network through stimulation. Granitic and metamorphic formations are often favourable due to their high heat retention and brittle fracture behaviour.
4. **Stress field analysis:** Understanding the in-situ stress regime is crucial for designing an effective reservoir stimulation strategy. Stress field analysis determines the orientation and magnitude of principal stresses, helping predict how fractures will propagate during hydraulic stimulation and informing the

orientation and spacing of production and injection wells. Regions with favourable stress conditions enable efficient permeability enhancement while minimizing the risk of induced seismicity.

5. **Water availability and sustainability:** Geothermal projects require a sustainable water source to maintain long-term fluid circulation within the reservoir. Site investigations assess potential water sources, such as deep saline aquifers, surface water bodies, or recycled water from industrial processes.

By investigating these factors, project developers can make informed decisions about whether to proceed with exploration drilling. The results of desktop studies and geophysical investigations guide well placement, reservoir development strategies, and overall project feasibility.

Exploration

Prior to drilling a large-diameter well that would be used to either produce hot water or re-inject cooled water into the geothermal reservoir, a project developer will drill smaller-diameter exploration wells (also known as slim wells) into the reservoir to confirm the resource potential and assess key subsurface conditions. These wells provide direct temperature measurements to verify that the heat available is sufficient for power generation. In addition, they are used to test and refine the physical, mechanical, and geomechanical properties of the reservoir, which guide the design of EGS drilling and stimulation plans in locations where permeability must be artificially enhanced.

Key characteristics assessed during exploration drilling:

- **Rock type and strength** determine drillability, rate of penetration, and wellbore stability, and are particularly important for directional drilling in harder-rock formations.
- **Orientation, density, and connectivity of natural fractures** impact the ease of permeability enhancement. Pre-existing fractures can act as fluid pathways and reduce the energy required for stimulation.
- **In-situ stress regime (magnitude and orientation)** are critical for designing hydraulic stimulation plans. Understanding stress conditions helps optimize fracture propagation while minimizing the risk of unwanted seismicity.
- **Permeability and porosity** are typically very low in EGS reservoirs but are assessed to establish baseline conditions before stimulation. Even small amounts of natural permeability can influence fluid circulation efficiency.
- **Thermal conductivity and heat capacity** govern heat transfer within the reservoir and influence long-term thermal recovery and sustainability.

These findings inform reservoir development strategies, helping to optimize well placement, drilling techniques, stimulation methods to enhance fluid circulation, operating pressure, and the rate of heat extraction while minimizing operational risks and costs.

Exploration wells are typically smaller in diameter than full-scale production wells and are not designed for long-term production. As a result, exploration wells are considered sunk costs rather than long-term assets. For this reason, they are designed to be drilled as cost-effectively as possible. However, some exploration wells may be repurposed during geothermal operations as monitoring wells. For example, these wells may be used for microseismic monitoring during reservoir stimulation and production, providing additional value to the project by measuring and characterizing the nature of microseismic activity associated with a project.

Well design and configuration

Well design and configuration are crucial for optimizing the extraction of geothermal energy. In conventional hydrothermal systems, wells are typically drilled vertically or with a slight deviation to intersect naturally permeable zones, such as fractures in the rock. However, in EGS projects, where permeability must be created through stimulation, there can be more flexibility in well placement. Horizontal or highly deviated wells can be used to maximize contact with the artificially created reservoir, increasing fluid flow, heat extraction, and long-term performance of the geothermal asset.

Well diameter is another important factor in well design. Geothermal wells are generally larger in diameter than oil and gas wells to sustain higher fluid flow rates than is typical in the oil and gas industry. This makes it difficult to extrapolate geothermal costs from available oil and gas well cost data, as larger-diameter casing tends to be more expensive and may require higher-powered drilling rigs. Diameter is a key metric as it directly impacts flow rate, a key determinant of the levelized cost of energy (LCOE), as well as system efficiency.

To determine diameter, it is important to understand how wells are lined with steel (casing). Casing is installed in layers that become narrower with greater depth. Geothermal wells are usually designed from the bottom up, meaning that the production (bottom) casing size determines the sizes of the intermediate and surface casings (Figure 27; Finger & Blankenship, 2010). Production liner sizes are typically 7-inch for smaller geothermal wells and 9 5/8-inch for higher-flow applications. For context, oil and gas wells are typically 2-3/8 inches to 4-1/2 inches in diameter (Tubing, 2025).

Larger-diameter wells allow for greater flow rates, which can improve overall power output, but they also come with higher drilling and casing costs. Choosing the right diameter is a balance between sustainably maximizing energy production and controlling expenses.

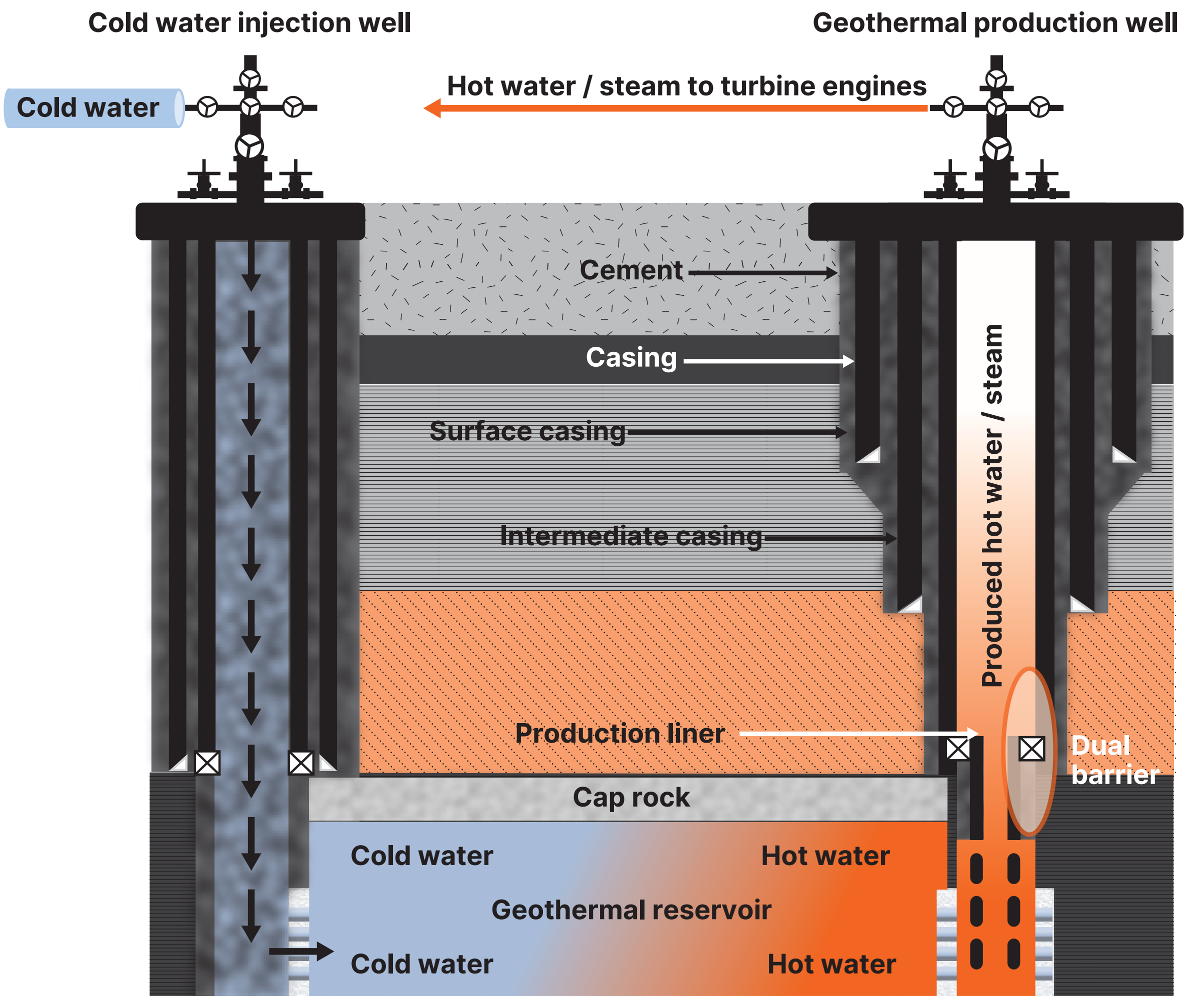
Well depth also affects design complexity. As depth increases, additional casing strings are required to manage high temperatures, pressure changes, and rock stability. Deeper wells can access hotter rock, which improves efficiency, but they require more casing and potentially more complex drilling techniques to ensure long-term integrity.

Finally, well configuration—whether a project uses a doublet (one injector, one producer) or a triplet (two injectors and one producer)—affects overall system performance. A doublet is simpler and more cost-effective but may provide less pressure support over time. A triplet, on the other hand, can help maintain pressure and improve fluid circulation, reducing the need for additional pumping power. Proper well configuration is crucial for balancing sustainability, efficiency, and operational costs in an EGS project.

By carefully considering design choices like well orientation, diameter, depth, and configuration, developers can optimize geothermal systems for maximum heat extraction, long-term performance, and economic feasibility.

FIGURE 27

Schematic diagram of geothermal wells. Adapted from Abid et al. (2022).



Reservoir stimulation

In an EGS project, stimulation is a critical step in creating permeability within hot, low-permeability rock, allowing fluid to circulate and extract heat. Unlike conventional hydrothermal systems, where fluid moves naturally through porous or fractured rock, EGS requires engineered methods to enhance or create permeability. The cost of stimulation can vary significantly depending on the method used, the number of injection intervals, the success of the initial stimulation, and whether restimulation is required in the future.

Traditionally, EGS projects have relied on shear stimulation, a process that increases permeability by reactivating pre-existing natural fractures within the rock. When high-pressure fluid is injected, it raises pore pressure and reduces the friction holding fractures closed, allowing them to slip along their natural planes. This creates a network of connected flow pathways that improve fluid circulation. Shear stimulation is often a lower-cost approach, but its success depends on the presence and orientation of natural fractures, which are not always optimally located for geothermal development.

More recently, multistage hydraulic fracturing techniques from the oil and gas industry have been adapted for EGS to provide better control over permeability enhancement. In this approach, the well is divided into multiple stimulation zones (stages) along its length, and each stage is stimulated separately. The fluid pressure during stimulation is high enough to create new fractures rather than relying on the presence of natural fractures. This method allows for a more even distribution of permeability throughout the reservoir, improving overall flow rates. However, each additional stage increases costs, as separate treatments must be applied to each interval.

Some recent EGS projects, such as those at Utah FORGE and Fervo Energy's Project Red and Cape Station projects in the United States, have also tested the use of proppant—small, solid particles (such as sand or ceramic beads) injected into fractures to keep them open after stimulation. In traditional shear stimulation, fractures can gradually close over time due to stress redistribution, potentially reducing flow rates and requiring restimulation. Proppant-based methods help maintain open pathways, improving long-term injectivity and productivity. While this approach adds upfront costs, it can significantly reduce the need for future interventions, leading to greater overall efficiency and lower lifetime costs.

Beyond the stimulation method itself, the number of injection intervals plays a major role in project economics. More intervals generally increase reservoir connectivity, improving heat extraction and power generation. However, each interval requires additional treatments, increasing costs. If stimulation is too limited, the reservoir may underperform, leading to lower injectivity (how easily fluid enters the reservoir) and productivity (how much hot fluid can be extracted). The success of the initial stimulation is crucial—if fractures remain well-connected and open, the well will deliver higher flow rates for longer periods, reducing the need for costly restimulation.

However, over time, stress changes in the rock can cause fractures to gradually close, reducing fluid circulation and potentially requiring re-treatment to maintain reservoir performance.

Ultimately, an effective stimulation plan must balance upfront costs with long-term efficiency. While newer methods like multistage hydraulic fracturing and proppant injection require greater initial investment, they can increase flow rates, improve heat recovery, and reduce long-term operational costs. The optimal approach depends on factors such as reservoir conditions, drilling depth, and target temperature, all of which influence project economics. As stimulation technology continues to evolve, improved permeability enhancement techniques will be critical in making EGS a competitive and scalable renewable energy solution.

Pumps

Pumps play a crucial role in EGS by facilitating fluid circulation through the reservoir and transporting the heated fluid to the power plant at the surface. Unlike conventional hydrothermal systems, where natural pressure gradients often drive flow, EGS typically requires active pumping to maintain both injection and production rates due to the reservoir's lack of natural permeability. The amount of energy required for pumps can have a significant impact on the LCOE and is important to account for in estimates.

In injection wells, pumps are needed to overcome high pressures at depth and force fluid into the artificially stimulated reservoir. This pressure is necessary to sustain fluid flow through the fracture network and ensure sufficient heat exchange within the rock. In production wells, pumping may also be required to lift the heated fluid to the surface, particularly if the natural formation pressure is insufficient to drive flow. However, in some cases, the injection pressure alone can create enough of a pressure differential to push the fluid back to the surface without the need for a production pump. This occurs when the pressure applied during injection is transmitted efficiently through the fracture network, generating sufficient artesian flow in the production well.

Several factors guide pump selection, including well diameter, pump set depth, hydrostatic water level, reservoir pressure, and injection pressure. A larger well diameter accommodates bigger pumps with higher flow capacities while reducing frictional resistance. Reservoir pressure and injection pressure are especially critical in EGS, where permeability is artificially enhanced. Unlike conventional hydrothermal systems, where fluid may flow naturally due to pressure differences, EGS typically requires higher injection pressures to maintain circulation.

The productivity and injectivity index of the reservoir also plays a key role in pump selection. The injectivity index measures how easily fluid can be injected into the reservoir, while the productivity index reflects how efficiently the production well delivers fluid to the surface. A low injectivity index means higher injection pressures are needed to sustain flow, increasing pumping requirements. Similarly, a low productivity index may require a more powerful pump to lift fluid from the reservoir, increasing energy consumption. The interplay between reservoir stimulation and operational pumping requirements is therefore very important, as a well-stimulated reservoir with high injectivity and productivity reduces the strain on pumping systems, improving efficiency and lowering operating costs.

The two main types of pumps used in geothermal applications are line shaft pumps and electrical submersible pumps, each with advantages depending on well conditions.

- **Line shaft pumps** have an electric motor at the surface, with a long shaft extending down to an impeller submerged in the vertical portion of the well. They are typically used in shallower, larger-diameter wells where frictional losses in the shaft are manageable.
- **Electrical submersible pumps** have both the motor and impeller placed in the wellbore (regardless of well geometry), reducing friction losses and allowing for deeper installations. Line shaft pumps are more widely used in conventional pumped geothermal power projects, while electrical submersible pumps are used when the required pump set depth exceeds the depth limit of a line shaft pump (~600 m).

As pumps consume electricity to operate, they are often the greatest contributor to the system's parasitic load—the energy consumed by the plant itself, which reduces the net power output. Excessive pumping requirements can significantly impact the overall economics of an EGS project. Optimizing pump selection based on well conditions, reservoir performance, and energy efficiency is crucial to ensuring stable circulation while maximizing net power generation.

Surface infrastructure

The economics of surface infrastructure in an enhanced geothermal system depend on plant selection, thermal efficiency, local climate conditions, pipeline and wellfield layout, fluid chemistry, cooling system choices, and overall energy consumption.

- **Binary Organic Rankine Cycle (ORC) plants** use a heat exchanger to transfer heat from the subsurface fluid to a working fluid that drives a turbine. ORCs are preferred for lower-temperature resources (<200°C) but have lower efficiency due to the additional heat exchange process.
- **Flash plants (single- or double-flash)** achieve higher thermal efficiency by directly converting steam into mechanical energy. However, they require higher fluid temperatures and sufficient reservoir pressure.

Fluid chemistry also impacts plant operations. Scaling and corrosion potential must be managed to prevent mineral buildup in turbines, heat exchangers, and reinjection wells, as scaling and corrosion can increase maintenance costs and reduce overall efficiency.

Cooling system selection is another key factor in plant economics. In a geothermal power plant, a cooling system is essential for rejecting waste heat and maintaining efficient power cycle operation. After the heat it carries is extracted to generate electricity, the working fluid or steam must be cooled and condensed before it can be recirculated.

- Binary plants rely on a secondary working fluid (such as isobutane or pentane) that vaporizes when heated by geothermal fluids. After expanding through a turbine to generate electricity, the working fluid must be cooled and condensed back to liquid form so it can be reheated and used again, in a continuous cycle.
- Flash plants use high-temperature geothermal steam to spin a turbine. Once the steam exits the turbine, it must be cooled and condensed back into water before being reinjected into the reservoir. Effective cooling ensures that the condenser maintains low-pressure conditions, maximizing steam expansion through the turbine and improving power generation efficiency.

Air-cooled systems eliminate the need for water consumption but can lead to reduced efficiency in hot and humid climates. Water-cooled systems, while more efficient, require access to a reliable water source and additional infrastructure for cooling water treatment and disposal (Bharathan, 2013). These cooling systems also contribute to a plant's parasitic load, alongside the aforementioned pumping requirements.

The efficiency of cooling systems is influenced by local climate conditions, particularly the wet bulb temperature, which reflects air humidity and temperature. In air-cooled systems, lower wet bulb temperatures enhance heat dissipation, improving efficiency. However, in hot and humid climates, reduced heat absorption by the air can decrease performance. Water-cooled systems, while more efficient overall, also depend on the wet bulb temperature—higher temperatures require more energy to cool the water, reducing efficiency. In western and northwestern Canada, where climate conditions vary across the region and through the year, cooling system design must consider local wet bulb temperatures to optimize performance and improve plant economics.

Gathering pipes: Unlike conventional hydrothermal systems that require extensive surface pipelines to connect wells to the plant, EGS wells can be drilled right next to the power plant, minimizing pipeline costs and heat losses. Instead of achieving well offsets at the surface, directional and horizontal drilling allow for subsurface lateral displacement, further improving efficiency and reducing land use requirements.

Finally, scalability and modularity play a role in long-term project economics. Binary plants are often more modular, allowing for staged development and gradual capacity expansion, which can help manage capital costs. Flash plants, while requiring higher initial investment, benefit from greater efficiency at larger scales. By optimizing plant design, cooling strategies, well placement, and fluid handling, EGS projects can enhance energy production while reducing operational costs, making them more competitive with other renewable and conventional energy sources.

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