Chapter 5

The Oil and Gas Industry Role: Technology Transfer, Development, Acceleration, and Scale

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All geothermal technologies will realize near term benefits from oil and gas technology spillover, providing quick wins and achievable learnings projected to deliver 20 to 43 percent in cost savings, depending on the type of geothermal technology.

I. Introduction

There are a number of synergies between geothermal technologies and the skills, expertise, technologies, and resources of the oil and gas industry. In this Chapter, we examine the role of the oil and gas industry in Texas, with its supportive policy and regulatory regime for subsurface energy extraction, and a broad social license for drilling operations, to accelerate the development and deployment of geothermal technologies and projects. While the oil and gas industry has been hesitant historically to invest in conventional geothermal technologies, as appropriate locations to develop them are increasingly scarce and geographically limited, the oil and gas industry could play a particularly important role in advancing new, more globally scalable applications that could expand the resource base of geothermal energy into sedimentary basins and Hot Dry Rock (“HDR”) applications.

However, to spur significant increases in the scale and pace of geothermal development, and encourage engagement of the oil and gas industry in these concepts, it is essential to demonstrate a pathway toward cost reduction to show investors and other stakeholders that geothermal can be a competitively priced energy source.

This Chapter reviews the current range of surface and subsurface geothermal technologies, and their strengths and limitations, with a focus on supply and demand in Texas. A technology roadmap is introduced, applicable across all geothermal technologies, to provide a framework to describe technology maturity and potential market viability (elements to support markets with sufficient supply and demand to warrant major investor interest). We consider the key levers and opportunities to the lower cost of geothermal technologies, applying three
main types of learning, including: (1) spillover from the oil and gas industry, (2) economies of scale, and (3) learning by research and development, and predict potential cost reductions that can be achieved across multiple geothermal technologies. We conclude by examining the role of collaboration models to address gaps in innovation, and the need for new business models within oil and gas to accelerate the pace of industry engagement in geothermal.

II. Background

Geothermal energy uses the heat generated in the Earth’s subsurface, either through Direct Use concepts (as discussed in detail in Chapter 2, Direct Use Applications), or for electricity generation, (as was discussed in Chapter 1, Geothermal Electricity Production.) Geothermal heat in the form of natural hot springs has been used by humans for millennia, and the first electricity generation from conventional hydrothermal reservoirs dates back to the early 1900s (IRENA, 2021a). Geothermal heating and cooling for buildings and industrial applications has grown since 2015 by 72 percent, to about one exajoule per year predominantly in the United States, Europe, and China (Lund & Toth, 2020). Geothermal energy for electricity generation has grown more slowly, due to limited conventional resources, generating about 94 terawatt hours, with capacity additions largely in Indonesia, Kenya, Philippines, Turkey, and the United States (IEA, 2020b).

Geothermal and upstream oil and gas developments have many overlapping features. Both require a detailed understanding of the subsurface, the drilling and completion of wells, the ability to understand and predict fluid flows in the subsurface, the handling of fluids for flow assurance, and for some applications, management of large-scale projects. Due to the nascent state of scalable geothermal technologies, there is significant potential to increase performance (e.g., efficiency, reliability, expansion to lower quality reservoirs), and to lower costs.

Technologies that share similar ancestry, such as geothermal and upstream oil and gas, may have the potential to achieve this radical, ‘step change’ style innovation by building on one another’s strengths and resources (Arthur, 2009). For example, offshore wind, through its similarity to the oil and gas industry’s geotechnical, logistics, and project management requirements, relies on strong spillover potential from the oil and gas industry (IEA, 2019). The potential technology spillover between geothermal and upstream oil and gas could be greater than examples like offshore wind, due to the greater number of transferable disciplines between the two. Transferable skills from oil and gas to geothermal are broad, and include resource characterization and exploration, drilling and completions, operations and maintenance, and risk management and mitigation.

There are, however, a number of differences between geothermal and the upstream oil and gas industry, including the types of reservoirs, volumes of fluids produced, temperature variations, fundamental customer base, and the underlying business model. Unlike upstream oil and gas, which produces a commodity that is transported for local or global use, Direct Use geothermal delivers solutions for distributed customers at their location, specific to their needs. In the case of geothermal electricity generation, projects require a new supply chain that is very different from the oil and gas industry. Instead of barrels, pipelines, refineries, trains, and ships, projects require utility grid connections, enabling power markets, electricity off-takers, and power purchase agreements. “Operating” a geothermal project, unlike oil and gas production, requires entities to become utilities. This is a concept that is met with varying levels of unease by oil and gas entities, particularly within the “parent” of major international oil companies, as it represents a fundamental shift in business model that is difficult to enact on a company-wide level while beholden to shareholder pressures.

We will consider in Section III of this Chapter how transfer of existing technologies from the upstream oil and gas industry might impact geothermal cost in the coming decades. We will then consider how a shift in thinking and business model approaches within the oil and gas industry may ease the transition of oil and gas entities into the geothermal space.

III. Technology Transfer from Oil and Gas to Geothermal

Texas industry and academia have helped to expand the frontiers of oil and gas production, and boost the efficiency of extraction. For example, the unconventional oil and gas revolution began in the 1990s with Mitchell Energy’s focus on the Barnett Shale in Texas, and as unconventional drilling techniques were applied in the Permian basin,
production has increased substantially. Today, Texas is the fourth largest oil producing entity in the world (EIA, 2021; Rystad Energy, 2021). As the world increasingly looks to transition to clean energy, geothermal, and its synergies with the oil and gas sector, has become a natural focus area for the oil and gas industry.

There are many examples of technology transfer between the two industries. For example, the first polycrystalline diamond cutter (“PDC”) bits, now responsible for more than 90 percent of oil and gas well lengths drilled globally, were designed for geothermal use in the 1970s, and first tested in a petroleum well for geothermal use in South Texas (Scott, 2021). In the last two years, a Texas based collaboration led by NOV and Texas A&M, performing work at the United States Department of Energy's Frontier Observatory for Research in Geothermal Energy (“FORGE”), utilized PDC bits alongside oil and gas optimization technologies and workflows, achieving double the expected rates of penetration through hard, granitic rock at over 230 °C (446 °F) bottom hole temperature (Sugiura, et al., 2021).

A. What is Needed From Oil and Gas if Geothermal Deployment is to Accelerate

In this Chapter, we focus on potential contributions from the oil and gas industry to support geothermal and, in turn, what key features the oil and gas industry would need to see to warrant increasing support for geothermal technology development. To this end, technology roadmaps are a visualization tool used in strategic planning that highlight the key challenges to achieving market penetration for a given technology (IEA, 2014; Amer & Daim, 2010). They help to provide a framework to link the current business environment with a vision of the future. Geothermal projects, particularly Deep Direct Use (“DDU”) and power projects, can require substantial early investment and carry high exploration risks. To warrant this level of investment, there must be a vision for how to reduce early exploration risks and/or achieve larger supply and market demand for geothermal technologies.

Most geothermal capacity today consists of shallow wells between 164 to less than 3,280 feet (50 to less than 1000 meters) for Direct Use heat or Conventional Hydrothermal Systems utilized to generate electricity. Unconventional well technology allows for more efficient approaches to Direct Use heat and cooling, and there is limited additional global capacity available to expand conventional hydrothermal resources. Changing the conceptual design and applications around Direct Use for heating and cooling, and expanding power generation capabilities into sedimentary basins and other Hot Dry Rock plays would substantially broaden the potential market for geothermal operators.

According to over 20 interviews with leaders of geothermal companies and geothermal experts conducted for this Chapter (see Appendix A of this Chapter for the list of participants), each geothermal technology that exists today, particularly the emerging scalable concepts like Closed Loop Geothermal Systems and Engineered Geothermal Systems, differs in its level of maturity in the field, and what improvements are needed to achieve greater deployment at scale (Visser, et al., 2019). Some geothermal technologies, such as Direct Use heating and cooling, satisfy these conditions for their current limited market penetration, but do not satisfy these conditions for an accelerated or broader scale up.

To deploy commercially at scale, geothermal technologies need to satisfy the following conditions:

- **Possess adequate heat transfer from the subsurface to Working Fluids:** Rock is a low conduction medium. When heat is taken out in the form of hot fluid transfer, the rock must be sufficiently conductive or, more often, utilize natural convective processes in the subsurface to maintain a continuous heat-exchange process.

- **Present long-term, sustained operability:** Technologies must be able to demonstrate long-term operability at a reasonable cost.

- **Offer sufficient resource to scale:** The technology must have sufficient supply to be deployed across multiple markets, or it may be unable to achieve economies of scale across supply chains and operations.
Demonstrate credible, competitive costs to an acceptable market range.

Find a viable market with demonstrated demand: There must be local demand for the energy source in question.

Other factors are also important. For example, social acceptance (social license to operate), and a supportive policy environment are essential to reduce non-technical risks that can cause project delays or cancellations.

Supportive public acceptance and policy environments lower risk perceptions for financiers due to more reliable timeframes for permitting or tax support mechanisms. Streamlined permitting timeframes, for example, can positively impact project valuations (Neupane & Adhikari, 2022). A detailed analysis of the impact policies have on the geothermal industry can be found in Chapter 12, Policy, Advocacy, and Regulatory Considerations in Texas.

For this Report, we focus on the potential role for deployment in Texas, which tends to view oil and gas activities and its contributions to the economy in a positive light, and which may allow for more field-testing opportunities for geothermal technologies than in other regions or countries. Texas also has a supportive policy and regulatory environment, and centuries of relevant subsurface jurisprudence to draw from, allowing operators, investors and insurers increased confidence in the stability of their investments. In many states and countries, geothermal energy faces an uncertain policy and high-risk and regulatory framework, providing little incentive for geothermal deployment.

IV. Overview of Geothermal Technologies

Geothermal technologies differ in their function (heating and cooling, or power generation), the type of resource they utilize, the maturity of the technology, and the resources needed to extract or transfer heat. The geothermal technologies described in Chapter 1, Geothermal and Electricity Production and Chapter 2, Direct use Applications can be divided into four categories: Conventional Hydrothermal Systems (“CHS”), Direct Use heating and cooling systems (“DHCS”), Engineered or Enhanced Geothermal Systems (“EGS”), and Advanced Geothermal Systems, which we use interchangeably in this Report with Closed-Loop Geothermal Systems (“CLGS”). Each holds opportunities for technology transfer from the oil and gas industry, along with key barriers and gaps that need to be addressed.

A. Conventional Hydrothermal Systems (“CHS”)

CHS reservoirs are found at major tectonic plate boundaries, and have minimal global footprint. CHS uses steam or hot water produced from the subsurface to run a turbine to produce electricity. This is generally done “Open to Reservoir,” where reservoir fluids may deliver subsurface gasses to the surface, including unwanted or hazardous gasses such as carbon dioxide (“CO2”) and hydrogen sulfide (“H2S”), though this is highly dependent on the nature of each geothermal reservoir and associated fluids. Projects are ongoing to capture and store produced CO2 from CHS reservoirs (Carbfix, 2021).

In 2005, Chevron became the largest geothermal operator globally, primarily due to ownership of CHS projects acquired following its purchase of Unocal. This engagement ended with the divestment of the business unit in 2016. Since 2016, oil and gas industry investments in the CHS space remained limited, until more recent investments by Chevron Technology Ventures, and Baker Hughes into Baseload Capital, for example. Despite limited industry investment, oil and gas industry practices, including standardized reporting across the industry, and project development, may help to bridge stranded markets, reduce costs, and allow access to funding and insurance for projects.
### CHS Resources Roadmap

<table>
<thead>
<tr>
<th>CHS Resources Roadmap</th>
<th>Adequate heat transfer</th>
<th>Long-term, sustained operability</th>
<th>Sufficient resource to scale</th>
<th>Demonstrate credible, competitive costs</th>
<th>Viable market, demonstrated demand</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>Potential</td>
<td>Case by case</td>
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Figure 5.1. CHS resources roadmap. Color-coding indicates the relative maturity of each condition. Red indicates the condition has been tested and is not satisfied. Green indicates the condition has been testified and is fully satisfied. Blue indicates the condition has not yet been met (in testing or to be tested). Gray indicates markets are on a local, case by case basis. Source: The Future of Geothermal Energy in Texas, 2023.

While CHS is a mature technology, the lack of a broad, global resource base has deterred substantial interest and investment by the oil and gas industry, though as we will explore in further detail in Chapter 6, Oil and Gas Industry Engagement in Geothermal, this trend may be changing.

**B. District Use Heating and Cooling Systems ("DHCS")**

Geothermal DHCS utilizes the subsurface (generally in very shallow low-temperature sedimentary basins) to store and source fluids to be used in commercial and residential buildings, agriculture, aquaculture, or other light industries for heating and cooling. DHCS operates in a “Closed to Reservoir” configuration, with no or nearly unmeasurable direct emissions, and at temperatures too low to support production of electricity. There are also Open to Reservoir DHCS technologies.

Direct Use heating and cooling systems are also referred to by a variety of other terms, including thermal energy networks, and many others. DHCS is a mature technology that can further benefit from oil and gas industry practices to reduce costs and expand resource access. For example, DHCS applications have traditionally required a large surface footprint. The use of directional drilling technologies and new well designs from the oil and gas sector has significantly reduced required surface area by up to a factor of 100, by drilling directionally from a single, small surface well pad (Thierry, et al., 2021). By monitoring heat exchange and surface heating needs closely, fluids can be directed appropriately in the subsurface to optimize heating and cooling exchange. DHCS may further benefit from increased social awareness and policy support to reduce cost burdens and increase access for consumers, new funding mechanisms such as leasing approaches that have been successful in residential solar, and inclusion in building codes in commercial settings.
As will be explored in further detail in Chapter 9, The Texas Startup and Innovation Ecosystem, a significant number of entrepreneurs and investors have entered the DHCS market. This includes non-petroleum investors such as Breakthrough Energy, Lennar Home Construction, Comcast Ventures, Bedrock Energy, and Google Ventures (through Dandelion Energy) in the United States, and several oil and gas related entities, such as Schlumberger’s Celsius Energy (France and Massachusetts), Causeway GT (Ireland and Texas), and Eden Geothermal (United Kingdom) (Thierry, et al., 2021; Schlumberger, 2021; O’Halloran, 2021; Shieber, 2021; Lundin, 2019). Additionally, Shell and Energie Beheer Netherlands drilled 1.7 mile (2.7 km deep) depth wells in the Netherlands. A further exploration license has been granted to Shell and D4 to provide 200 megawatts thermal of geothermal heating (DHC News, 2021; Ottevanger, 2021).

Companies researching DHCS applications at greater depths tend to use existing oil and gas assets, including data or wells to estimate or test heat potential, reducing exploration risk and costs. Networked or district DHCS concepts, despite the advantage of a larger resource base, have seen limited growth due to higher initial capital costs, and in many domains, higher regulatory burden. While operating costs are low, the relatively high upfront cost to install a Deep Direct Use (“DDU”) heating and cooling system deters many potential customers (Laterman, 2019).
C. Engineered or Enhanced Geothermal Systems ("EGS")

EGS targets hot metamorphic or sedimentary rock. Sedimentary basins comprise about 16 percent of the earth's surface, and thus are significantly more abundant than CHS resources (Neupane & Adhikari, 2022; Geiser, et al., 2016). EGS utilize either natural or hydraulically-stimulated fractures to create an underground reservoir. Fluid, usually water, is injected into the hot, fractured reservoir, and produced from nearby wells to generate electricity. As discussed in other Chapters of this Report, CO2 is being experimented with as a viable Working Fluid to replace water in some EGS concepts due to its lower critical point compared to water.

Sufficient, long-term reservoir flow can be challenging in EGS concepts, and finding (or creating) sufficient porosity and permeability in deep, hot rocks requires significant resources, energy, and cost. However, the recent tight oil and shale gas boom, with its origins in the State of Texas under George Mitchell's efforts to produce gas economically out of the Barnett Shale, has undergone several rounds of technological innovation over the past three decades. Many of these advances could be applied to reduce drilling times and costs of EGS. Horizontal drilling techniques have largely not been applied in EGS projects to date, but could provide a boost to efficiency, while well completion advances, particularly multi-zone completions and operational efficiencies achieved during tight oil and shale gas activities, could be applied to increase the productivity of EGS systems (Gradl, 2018). In this report, we refer to these potential improvements to EGS as a result of the application of oil and gas technologies “Next Generation EGS.”

A number of entrepreneurs have made strides into EGS, pursuing Next Generation EGS concepts to improve performance and efficiency. Current investors in EGS trials include the U.S. Department of Energy, Breakthrough Energy, Google Ventures, and drilling rig companies Helmerich & Payne (through Fervo Energy), Patterson UTI, and Chesapeake Energy (through Criterion Energy Partners) (Patterson-UTI, 2022; Terrell, 2021; Tiernan, 2021). The United Kingdom has at least two active EGS start-ups, United Downs (Geothermal Engineering Ltd (“GEL”)) and Eden Geothermal, both funded by a mixture of public and private funding (Eden Geothermal, 2021; GEL, 2021). Additionally, well testing at United Downs

![Figure 5.4. Days versus depth for Well 16A(78)-32. Recent oil and gas technology and practices from the shale boom can provide a step-change in performance as highlighted in drilling results at the United States Department of Energy Utah FORGE site. With oil and gas industry crossover, the first well in the campaign achieved best-in-class performance. Source: Winkler & Swearingen, 2021.](image)
recorded the highest lithium concentration ever tested in geothermal brines, and GEL announced it will produce 4,000 tons of lithium annually from its next sites starting in 2026 (Richter, 2021). Lithium is a critical mineral used in batteries, and the IEA estimates that lithium demand for clean energy technologies will grow by more than 13-fold by 2030 in a Net Zero Emissions by 2050 Scenario (IEA, 2022).

The oil and gas industry has largely shied away from EGS, and in particular from Traditional EGS concepts thus far, due to both technical and non-technical risk perception. As we’ve seen with recent investments, and will explore in further detail in Chapter 6, Oil and Gas Industry Engagement in Geothermal, there appears to be more interest from industry in engaging in Next Generation EGS concepts. Historically, the oil and gas industry backed some of the field trials in EGS (e.g., Woodside’s Habanero and Cooper Basin), but companies largely exited after a number of failures requiring re-drills, without achieving consistent commercial rates (Hogarth & Holl, 2017; Breede, et al., 2013). The high cost, operational difficulties in producing and injecting in very tight EGS reservoirs, and induced seismicity risks have dissuaded widespread oil and gas entity engagement in EGS to date. Supporting technologies that demonstrate EGS can operate long-term at commercial rates, drive down costs, and manage seismicity concerns would encourage investment into the technology.

D. Advanced Geothermal Systems (“AGS”)

AGS are next generation geothermal technologies, which primarily operate in a Closed to Reservoir configuration. SuperHot Rock (“SHR”) systems are also sometimes grouped into AGS. For this Section, we focus on Closed-Loop Geothermal Systems (“CLGS”), which covers a range of Closed or partially Closed to Reservoir concepts for electricity generation, including Hybrid Geothermal Systems. The CLGS approach, if successful, would allow geothermal to achieve no/low greenhouse gas emissions, and also allow use of more efficient engineered Working Fluids, which will be discussed in greater detail later in this Chapter. Similar to CHS and EGS, waste heat can be used similarly as an adjunct value chain.

CLGS trials largely rely on thermal conduction in rock (a poor conductor) from long wellbores, whereas CHS relies on convection to support heat transfer. The oil and gas industry and customers looking for reliable, off-grid, baseload power, including the U.S. Department of Defense (“DOD”) and several municipalities in Texas, are watching...
current field trials in Texas and elsewhere with interest (Hayes, 2021; Sage Geosystems, 2021). In contrast to ESG and CHS, oil and gas majors have already made some steps into CLGS, and as we will see in Chapter 6, Oil and Gas Industry Engagement in Geothermal, have indicated significant enthusiasm for the concept. Chevron and BP invested in Eavor, which is field trialing in Canada and Germany, while Nabors has invested in Sage Geosystems, which is field trialing in Texas (Laureman, 2021; Veazey, 2021), and more recently, Baker Hughes invested in Greenfire, which is field trialing in California.

Recent well engineering advances are under investigation that may allow the creation of deeper and larger underground well networks to increase efficiencies gained from unconventional oil and gas drilling, helping to improve economics to allow sufficient upscaling of the technology (van Oort, et. al., 2021; Eavor, 2022). Sage Geosystems, for example, is trialing a hybrid closed-loop system in South Texas that uses hydraulic fracturing to allow more fluid movement around the wellbore to improve heat exchange. With success, CLGS could provide an opportunity for geothermal to scale to sedimentary basins with significantly less risk of induced seismicity, and without the scaling and corrosion risks seen in CHS and EGS reservoirs.

V. Geothermal Power Plant Types and the Efficiency Evolution

Hot geothermal liquids such as water and steam are converted into electricity using a variety of processes, with higher enthalpy (generally higher temperature) geothermal fluids driving higher efficiencies (O'Sullivan & O'Sullivan, 2016). Geothermal energy is always “on,” and combined with high overall plant uptime, this results in high capacity factors (the percentage of time that a plant is generating electricity) of between 60-90 percent for individual plants, and a global average of just under 85 percent in 2020 (IRENA, 2021b). Capacity factors are, however, highly influenced by declining reservoir pressure and operations. Operations and maintenance ("O&M") costs can be low for new plants, but may rise substantially, particularly if new wells need to be drilled to maintain pressure.
Geothermal power plants have low conversion efficiencies compared to other thermal power plants (Moon & Zarrouk, 2012; Gisler & Miller, 2021). Conversion efficiency, as defined by Moon and Zarrouk (2012), is the ratio of net electric power generated (megawatts electric) to the geothermal heat produced/extracted from the reservoir (megawatts thermal). Geothermal power plants have conversion efficiencies that range from one to 21 percent, with a global average of about 12 percent (IRENA, 2021b). One major limitation of geothermal power production is the low turbine efficiencies achievable with current technologies. Additionally, over time, scale and corrosion from geothermal brines can impact operability and plant efficiency, resulting in higher O&M costs. This presents a significant opportunity for innovation, and new ways of doing to increase the economic attractiveness of geothermal projects across technologies, entirely outside of subsurface considerations.

The efficiency of a geothermal power plant depends first on the enthalpy and heat transfer capabilities of the working fluid driving the turbines. Historically, dry steam plants, where steam from geothermal wells directly drives a turbine to generate electricity, usually above 225 °C (437 °F) bottom-hole temperature, comprise most of the historical power generation capacity in the United States (Robins, et al., 2021). Dry steam plants have relatively high efficiencies of around 12 to 21 percent (Moon & Zarrouk, 2012). In comparison, coal plants reach about 600 °C (1,112 °F) and, depending on technology, have efficiencies of about 35 to 45 percent (Carbon Brief, 2020).

In the last twenty years, flash steam plants have become common as higher temperature CHS resources become more scarce. Flash steam plants use hot geothermal fluids greater than 182 °C (360 °F) pumped into a surface tank, with vapor from the rapid expansion of fluids into the tank (flashing) driving a turbine (Harvey & Wallace, 2016). The pressure drop can encourage silica scale to occur on the inside of piping, acting as an insulator and reducing efficiencies. With additional cost, flash plants can be constructed and run with multiple stages to increase heat recovery and plant efficiency.

Binary plants (also called Organic Rankine Cycle, or “ORC”) systems have become the most common type of new plant installed in the United States, and are used for lower enthalpy fluids with temperatures ranging from about 90 °C to 180 °C (194 °F to 356 °F) (Robins, et al., 2021; Hijriawan, et al., 2019; El Haj, et al., 2017). Geothermal fluids are pumped into a heat exchanger, where they heat and flash a secondary organic working fluid (e.g., isopentane, pentafluoropropane), which in turn drives a turbine. For low grade heat applications, Hartulistiyoso, et al. found optimal plant efficiency of around seven percent using more commonly available working fluids (Hartulistiyoso, et al., 2020).

Innovation in geothermal power plants and system Working Fluids may be a key lever to improve economics and expand the resource base for new geothermal technologies. Recently, companies have utilized hybrid systems combining other power sources (fossil fuel or renewables) with geothermal to help increase the overall efficiencies of the power production system (Robins, et al., 2021). Innovations in Working Fluids may play a key role in increasing geothermal efficiencies, and expanding applicability to lower enthalpy ranges (Song, et al., 2020). For instance, the Southwest Research Institute in San Antonio, Texas has designed a supercritical carbon dioxide (“sCO2”) turbine in partnership with Sage Geosystems that could achieve an efficiency greater than 20 percent in reservoirs at approximately 175 °C (347 °F), and around 3.7 miles (six kilometers) in depth (Nielson, 2021). The system is set to perform an initial field test on a well drilled in South Texas in a sedimentary basin in 2023.

There has also been increasing interest amongst oil and gas entities in the promise of direct heat to electron transfer, or Thermo-Electric Generation (“TEG”) as a potential generation solution for not only geothermal wells, but also electricity production from waste industrial heat generally. TEG concepts are further from commercial...
viability than other generation contenders, however, and rely on significant amounts of rare earth metals, creating a potential challenge to reaching commercial scale (Elghool, et al., 2017).

VI. The Role of the Oil and Gas Industry

As discussed, geothermal has strong potential crossovers with the oil and gas industry, as both industries strive to characterize and predict fluid flows from the subsurface, use wells to access resources, handle facility and fluid production at the surface, and execute large-scale projects. Value could be quickly gained by the geothermal industry in application of some of the processes, technologies, and assets from the oil and gas industry. Spillover processes and technologies may prove critical to lower cost and improve efficiencies (summarized in the Cost and Technology Improvements Section of this Chapter and Appendix B). Importantly also, the oil and gas industry can provide the needed funding, in-kind and operational support, and even lease holdings for geothermal field trials.

The oil and gas industry has created a number of design and resource standards that allow the industry and other stakeholders, such as financiers, insurers, and governments, to characterize projects and their risks. The Petroleum Resources Management System, developed by several oil and gas industry organizations, is the widely held standard for resource reporting to the U.S. Securities and Exchange Commission (USSEC, 2008). The American Petroleum Institute (“API”) has created a number of standards for oil and gas well operations and construction that are used as global references (API, 2021).

These standards serve to create a common language, from drilling wells, to building plants, to estimating reserves. They serve to communicate processes, to allow for a quicker spread of knowledge and practices across industry, and to gain support from a wider group of experts, investors, insurers, and regulators. Entrepreneurs from oil and gas entering the geothermal domain have encountered difficulties gaining financing and insurance without these standards, and without clear regulations. For geothermal operations in sedimentary basins, new standards and regulations may be needed to communicate resource and reserve profiles, establish viability of long-term production, and to facilitate a streamlined well and project permitting process.

Figure 5.8. Thermal imaging of a reservoir flow test showing high temperature fluid flowing through the piping and tank system at the DEEP Earth Energy sedimentary geothermal pilot project in Saskatchewan, Canada. The DEEP project is an example of how oil and gas methods and technology transfer can enable new concepts and capabilities in geothermal. Photo credit: DEEP Earth Energy

These key standards would support fledgling companies to communicate project opportunities and risks in a common manner, allowing more reliable access to financing and expanding the reach of geothermal.

A demonstrable demand for geothermal energy is needed to justify increases in policy support and investment in geothermal field trials. There are several technologies that may allow for larger markets, but the oil and gas industry currently keeps the notion of a CHS market in mind when assessing geothermal potential. The growth of DHCS applications, and field trials of EGS and AGS, could help the oil and gas industry further diversify into clean energy, as geothermal provides investment opportunities with strong overlap in upstream skills and assets, and supports employment transition opportunities for oil and gas workers. Governments, both Federal and State, can incentivize geothermal development by insuring projects, or by providing grants or concessional loans to “first of a kind” demonstration projects. These types of incentives are considered in further detail in Chapter 12, Policy, Advocacy, and Regulatory Considerations in Texas.

Texas is one of the preeminent locations globally for describing and exploiting subsurface resources. It provides a unique opportunity to drive geothermal innovation forward given its people, assets, institutions,
and supportive social and policy environments. Texas
research institutions and universities across the State
have contributed significantly to the advancement of
the oil and gas industry, and developed world leading
expertise in geoscience and petroleum engineering.
Texas has over 1.3 million wells drilled, with hundreds of
thousands of well logs, drilling and completion reports,
seismic, core data, and other information that can fast
track subsurface exploration and derisk early project
costs (TWDB, 2022). For example, existing wells can
provide an opportunity to confirm temperatures and
reservoir quality in untested formations. The temperature
range of the Texas Gulf Coast fits well for testing new
concepts for DHCS, EGS and AGS. Perhaps most uniquely,
the supportive social and policy environment allows for a
natural fit for entrepreneurs looking to test geothermal
innovation in a supportive community.

A. Learning, Technology Transfer and Cost
Reduction

The assets, workforce, and subsurface conditions of
the State of Texas provide a unique opportunity to test
the physics and commerciality of geothermal concepts.
Equally important is the ability to demonstrate a pathway
to lower costs to highlight to investors and other
stakeholders that geothermal can be a competitively
priced energy source. Given uncertainty on the timescales
of actual implementation in the field, it is important to
look at the key levers and opportunities to lower costs
from existing assets and ways of working from the oil and
gas industry, economies of scale, and benefits of further
research.

1. Learning

The rate and nature of technological change and cost
reductions are critical assumptions for the assessments
of a technology’s long-term suitability to provide energy
at an affordable price. Historically, for power production
technologies, costs for technologies decrease as
experience accumulates (McDonald & Schrattenholzer,
2001). Yeh and Rubin summarize a broader scope of
contributions to learning, including spillover effects,
learning by research and development (“R&D”) and
economies of scale, as well as a series of factors
behind apparent cost increases, for example, in early
development due to “first generation” technology costs
(Yeh & Rubin, 2012).

This Chapter applies three main types of learning that
can reduce future costs in geothermal, including: (i)
spillover from the oil and gas industry, (ii) economies of
scale, and (iii) learning by R&D. Learning by R&D is further
split into technologies known to be trialing now (within
the next one to two years), and those that require further
funding (Table 5.1).

Learning-by-doing, where cost improvements are
created by experience, helping to deliver increasing
cost efficiencies, are not explicitly modeled to avoid
double-counting efficiencies gained by spillover or
economies of scale. The methodology employed in this
Chapter includes learning-by-doing within the umbrella
of economies of scale learning. Cost increases during
first technology trials, initial scale-up, troubleshooting,
or increases in supply chain costs, are also not explicitly
modeled (although these may play a role in the future).
The learning curve here adapts that from Yeh and Rubin,
but uses spillover and economies of scale in place of
learning-by-doing.

\[
Y = (Y_{pre-dev} + Y_{dev} + Y_{misc})(1 - (b_{og} + b_{eos} + b_{rd}))[1]
\]

Where:

- \(Y\) = levelized cost of electricity (or heat) at time \(T\), see
  below
- \(Y_{pre-dev}\) = contribution of pre-development (exploration)
costs to levelized cost of electricity (or heat) at time 
  \(T\)
- \(Y_{dev}\) = contribution of development costs to levelized
cost of electricity (or heat) at time 
  \(T\)
- \(Y_{misc}\) = contribution of miscellaneous costs to levelized
cost of electricity (or heat) at time 
  \(T\)
- \(b_{og}\) = learning curve cost reduction resulting from oil
  and gas spillover
- \(b_{eos}\) = learning curve cost reduction resulting from
  achieving economies of scale
- \(b_{rd}\) = learning curve cost reduction resulting from
  research and development technology efficiencies

Types of learning are assumed to occur in different
time intervals as technologies mature through their
technology roadmaps (Table 5.1). Where applicable, oil
and gas spillover is assumed to occur in the short-term,
with quick and efficient crossover from the oil and gas industry. Economies of scale are assumed to take a minimum of five years for initial effects to be seen, as all technologies, despite maturity or resource base, require a further social license to operate, and supporting policy environments to allow scale-up. In many cases, these technologies of scale are facilitated by oil and gas spillover (e.g., multi-well pad efficiencies).

For technologies that are trialing now, it is assumed it will take at about five years for trials to be conducted, assessed, and re-deployed at some minimal scale. For technologies that are funded now, it is assumed that a minimum of about ten years is needed to research, build benchtop models, build field prototypes, and further deploy at scale.

Cumulative investment or stock of oil and gas spillover, economies of scale, and R&D are assumed to be maximized during the time intervals to allow for a best-case learnings transfer. Critical to this assumption is that global learnings of deployment across all technologies would be shared efficiently, and not just those occurring within the State of Texas. To do this effectively involves the interplay of companies, industry organizations, countries, and other entities. This is explored in more detail in the Collaboration and Innovation Models Section of this Chapter below (IEA, 2020a; 2020b; 2020c).

In a geothermal power example, Y represents the levelized cost of electricity (or heat) per kilowatt-hour (or megawatt-hour) generated (“LCOE(H)”). LCOE(H) can also be expressed directly as the net present value of fixed and variable costs needed to produce a unit of energy, typically a kilowatt or megawatt hour (IRENA, 2017; IEA, 2020).

Geothermal technologies are compared based on their current levelized cost of electricity (or heat) generation and future ability to drive down costs. The IEA’s Levelized Cost of Electricity (“LCOE”) model is used to calculate break-even LCOEs. Assumptions used in the LCOE model are noted in Appendix B, and the cost basis for each technology, before application of learning curves, are shown in Table 5.2.

### Table 5.1. Types of learning applied and their applicable time intervals. Source: Future of Geothermal Energy in Texas, 2023.

<table>
<thead>
<tr>
<th>Types of Learning</th>
<th>Description</th>
<th>Time Interval (Years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and Gas Spillover</td>
<td>Application of current technologies and practices. CLGS cost estimates already contain spillover assumptions</td>
<td>0 to 5</td>
</tr>
<tr>
<td>Economies of Scale</td>
<td>Applied dependent on achieving technology roadmap elements to enable manufacturing style projects: establishing physics, operability, social acceptance, demand, supportive regulatory environment</td>
<td>5 to 20+</td>
</tr>
<tr>
<td>Learning by R&amp;D: Trialing Now</td>
<td>Adopt and adapt R&amp;D, e.g., new turbine Working Fluids/ supercritical CO₂ turbines for concentrated solar power and novel subsurface well networks</td>
<td>5 to 20+</td>
</tr>
<tr>
<td>Learning by R&amp;D: Funding Now</td>
<td>R&amp;D funding and deployment increase well flow rates and/or to access higher temperature and difficult to drill reservoirs</td>
<td>10 to 20+</td>
</tr>
<tr>
<td>Learning by Doing</td>
<td>Applied on basis of overall technology learnings based on cumulative experience</td>
<td>Ongoing</td>
</tr>
</tbody>
</table>
Table 5.2. Geothermal technology initial capital cost basis. Estimates were assessed using the range of temperatures found across Texas up to about 6.5 kilometers (about 4 miles), or up to about 225 °C (440 °F). NREL’s Annual Technology Baseline assumes the use of flash plants are valid above 200 °C (392 °F). Sources: Beckers & Johnson, 2022; NREL, 2022; Beckers, et al., 2021; Flowers, 2021; NREL, 2021; IEA, 2020; IRENA, 2017; Mattson & Neupane, 2017; Rubin, et al., 2015.

<table>
<thead>
<tr>
<th>Geothermal Technology</th>
<th>Cost Range (2020 U.S. Dollar per kilowatt)</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHS</td>
<td>4120 – 5870</td>
<td>Cost range based on U.S.-based experience</td>
</tr>
<tr>
<td>DHCS or TEN</td>
<td>1400 – 1900</td>
<td></td>
</tr>
<tr>
<td>EGS</td>
<td>27 330 – 65 000</td>
<td>Cost range reflects NREL guidance spanning flash and binary power plants. In Texas, binary power plants may be likely given subsurface temperature gradients.</td>
</tr>
<tr>
<td>CLGS</td>
<td>5 750 – 14 375</td>
<td>Compared to other geothermal technologies, initial costs from CLGS sources contained some assumed oil and gas spillover.</td>
</tr>
</tbody>
</table>

Table 5.3. Project cost phasing by geothermal technology. Note: Annual operations and maintenance costs are assumed to be 2.5 percent of total project costs. Source: IRENA, 2017; IEA, 2020b.

<table>
<thead>
<tr>
<th>Project Cost Phase</th>
<th>CHS</th>
<th>DHCS</th>
<th>EGS</th>
<th>CLGS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-Development Survey, Exploration, Appraisal</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>Resource &amp; Fluid Characterization</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Development</td>
<td>85%</td>
<td>80%</td>
<td>86%</td>
<td>86%</td>
</tr>
<tr>
<td>Development well costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Drilling</td>
<td>24%</td>
<td>24%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>Completions</td>
<td></td>
<td></td>
<td>40%</td>
<td>40%</td>
</tr>
<tr>
<td>Power plant &amp; steam gathering system</td>
<td>55%</td>
<td>60%</td>
<td>24%</td>
<td>24%</td>
</tr>
<tr>
<td>Infrastructure &amp; interconnection</td>
<td>7%</td>
<td>7%</td>
<td>16%</td>
<td>16%</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>4%</td>
<td>10%</td>
<td>4%</td>
<td>4%</td>
</tr>
</tbody>
</table>

2. Technology Capital Costs

Learning parameters are applied separately to the different technologies, assets, and practices used to develop a geothermal project. The costs incurred at each project development phase are therefore estimated on the basis of reported phasing and geothermal and petroleum well cost comparisons (IEA, 2021; Thierry, et al., 2021; GTO, 2019; Nyberg & Howell, 2019; Gul & Aslanoglu, 2018; Lukawski, 2016; Kipsang, 2015; Lukawski, 2014; Mansure & Blankenship, 2013; Gehringer & Loksha, 2012).

Well completion costs are not separately split out for CHS and DHCS, as they are currently a minor component of cost. For electricity generation technologies, binary ("ORC") power plants are assumed given the temperatures and depths for Texas geothermal power resources (about 175 °C or 347 °F) (Blackwell, et al., 2011). Miscellaneous includes insurance and other project management costs.

Each project phase is further segmented into individual technology, practices, or assets, and assigned to one of the potential learning cost reduction parameters (see Appendix B for overview and sources). In addition, we estimate the range of cost reduction that could be realized for each technology based on cost savings achieved by the unconventional petroleum industry over the last three decades, industry interviews, and additional available literature (Jacobs, 2021; IEA, 2020b; IEA, 2020c; El Haj Assad, et al., 2017; Lowry, et al., 2017; EIA, 2016; Patel, et al., 2016; Rubin, et al., 2015; Scott, 2015; Augustine, 2011; Mansure, et al., 2006; Kotter, 1996).

Three scenarios were developed for each element based on a low, medium, or high range of cost reduction achievable. Not all oil and gas industry technologies or practices have been assessed. The deployment of geothermal technologies may benefit from practices not described here, whereas those discussed may not reach full potential.

4. **Modeling Results**

The cost reductions for the four geothermal technologies (CHS, DHCS, EGS, AGS) depend on their current maturity, level of incorporation of current spillover technologies, ability to scale, and applicable R&D technologies as outlined in Appendix B. The breakdown of the impact of different learning types, and the associated phasing of capital, is shown in Figures 5.7 to 15.3. Figures 5.7 to 5.9 indicate the range and midpoint of LCOE (or “LCOH”) achievable using the cumulative contributions from each of the three learning factors discussed above. Figures 5.10 to 5.13 highlight the phasing of capital cost savings resulting from the learning types discussed in this Chapter.

![Graph showing LCOE and LCOH ranges for DHCS and CHS](source: Future of Geothermal Energy in Texas, 2023.)
Figure 5.10. LCOE ranges for EGS and CLG, with cumulative reductions from learning factors. Source: *Future of Geothermal Energy in Texas, 2023.*

![LCOE ranges for EGS and CLG](image)

Figure 5.11. Mid-case capital costs by technology type before and after learning. Source: *Future of Geothermal Energy in Texas, 2023.*

![Mid-case capital costs by technology type](image)
Figure 5.12. Reduction in mid-case capital costs by project phase and learning type for CHS. Source: Future of Geothermal Energy in Texas, 2023.

Figure 5.13. Reduction in mid-case capital costs by project phase and learning type for DHCS. Source: Future of Geothermal Energy in Texas, 2023.
Figure 5.14. Reduction in mid-case capital costs by project phase and learning type for EGS. Source: 

Figure 5.15. Reduction in mid-case capital costs by project phase and learning type for AGS. Source: 
5. Discussion

Potential efficiency gains and cost reductions, largely against the backdrop of recent learnings from unconventional oil and gas technologies and practices, may provide LCOE(H) reductions of six to 25 percent across the range of geothermal technologies. Potential cost reductions are possible, and in some cases significant, even among mature technologies such as shallow DHCS and CHS. All technologies could see a near term benefit from oil and gas spillover that provides quick wins and achievable learnings. The full extent of learnings, projected to be between 20 to 43 percent, will depend on the level of investment support into demonstration and deployment projects, as well as early phase R&D funding. Early support of geothermal in Texas may allow the technologies time to trial and mature with success, allowing for first mover advantage in a new industry, and effective transitioning of people and resources in the 2030s and beyond.

B. Conventional Hydrothermal Systems

CHS has no market, per se, in Texas, but in areas outside of Texas, some cost improvement can be expected with a concerted effort to transfer learnings between the geothermal and oil and gas industries. The transfer of oil and gas practices, including reporting methodologies and drilling efficiencies may function to decrease the cost of CHS by an estimated six percent. The limited supply of CHS resources reduces the impact of economies of scale, but further use of multi-well drilling, and replicated topside designs could serve to reduce costs by another three percent. Spillover from research and development investments to improve EGS and AGS economics, particularly to improve turbine efficiencies or access higher heat, may in turn improve CHS, resulting in a further nine percent reduction in cost.

C. Direct Use Heating and Cooling Systems

DHCS is the only geothermal technology with relatively wide social acceptance that may allow, given supportive policies and market demand, relatively fast cost reductions from both spillover and economies of scale. For DHCS, oil and gas spillover would allow for a nearly ten percent near-term cost reduction, while economies of scale can reduce costs by over 20 percent. Additionally, other non-financial benefits, such as reduced surface area usage for development, may be attractive for many customers. The use of existing wells and data may allow significant cost reductions for most of the pre-development costs and risks.

D. Engineered (or Enhanced) Geothermal Systems

The range of EGS cost estimates is wide due to technology immaturity, and the range of Texas subsurface temperatures. In practice, this range will reduce once concepts are piloted in Texas, but this serves to highlight the level of technology uncertainty. EGS cost reductions get help from oil and gas spillover, resulting in over 11 percent reduction in costs, with upside enabling reductions of over 50 percent if the technology can reliably achieve commercial rates. R&D funding and learning are essential to driving EGS subsurface, well, reservoir, production, and plant efficiency levels to be competitive with other thermal power generation technologies (reaching around $60 USD per megawatt hour in a high learning case). EGS needs to be aggressively pushed in all areas of learning to achieve cost-competitive LCOEs, and relies heavily on early oil and gas spillover.

E. AGS (or Closed Loop Geothermal Systems)

AGS cost estimates carry some embedded oil and gas cost carryover assumptions, helping them start at a lower point than EGS, albeit with high uncertainty. In turn, AGS enjoys less impact from oil and gas spillover, and most near-term learning improvements rest on building economies of scale, which account for nearly 60 percent of cost improvements. Operators may experience cost increases as they trial the technology, and begin to troubleshoot surface and subsurface issues. AGS cost estimates approach $29 USD per megawatt hour with the combination of oil and gas spillover, economies of scale, and success with learning by trialing.

F. Emerging Technologies

R&D on the benchtop and in the field are essential to further drive down geothermal power generation costs. There are several technologies that could reduce costs across most geothermal concepts, including improved turbine efficiencies (and trialing engineered working fluids), accessing higher heat, enabling higher volume
rates (particularly supporting a larger onshore wellbore market, exploration of monobore well designs, or electrical-submersible pumps designed for geothermal applications), and enabling more connected subsurface wellbore designs. Some important elements not described well in literature are operational costs, and relatively high annual thermal degradation due to scaling that projects experience.

6. Oil and Gas Crossover is Key to Cost-Competitiveness

The oil and gas industry could play several important roles in the growth of geothermal, including early adoption of industry practices, reducing exploration risk in sedimentary basins, providing funding and direct resource support, and providing a model for industry standards and best practices. For example, early crossover in DHCS has demonstrated new subsurface design approaches, and is deepening and expanding the resource base for DHCS. The Direct Use market shows clear capabilities to upscale with oil and gas spillover, providing benefits to the industry in the form of smaller surface footprints, and enhanced control and efficiency on integrated subsurface and surface flows. DHCS, with its achievable path to lower costs and its higher maturity, provides a clear case for investment and expansion in Texas and other regions.

In Texas, EGS and AGS have the potential to drive toward LCOEs competitive with gas, and some solar photovoltaic and onshore wind, but this is heavily dependent on oil and gas spillover, particularly from unconventional well engineering practices, to drive improved efficiencies. EGS needs to demonstrate capabilities to develop and operate reservoirs reliably. AGS needs to demonstrate successful application of the physics of the technology in the subsurface, and demonstrate long-term operability. These challenges will need funding from the oil and gas sector and other private and public actors in the next few years for piloting, troubleshooting, iteration, and continued learning.

VII. Collaboration and Innovation Models

The above analysis suggests that there are pathways forward to lower and more competitive geothermal costs for electricity and heat generation. But the success of this model depends on building collaborations and further innovation in R&D, increasing social awareness and acceptance, developing stronger policy environments, and encouraging demand. Collaboration platforms may be a key way to accelerate action on all of these fronts. In this Section, we will consider collaboration models that have functioned successfully amongst private entities, and oil and gas industry entities in particular. Chapter 12, Policy, Familiarization, and Regulatory Considerations in this Report considers models for State policy recommendations to support the geothermal industry in Texas.

The drivers for a collaboration platform in the case of geothermal, are enabling enhanced and faster creativity in research, accelerating development and deployment realms, and fostering social acceptance. Collaborative platforms can provide the means and mechanisms to bring together actors from complementary disciplines, sectors, and communication realms (Winickoff, et al., 2021). Winickoff, et al. (2021) describe the cases of the National Nanotechnology Coordinated Infrastructure (“NNCI”) and the field of engineering biology that use social engagement to prevent miscommunication around the technologies, and raise public awareness and acceptance.

A. Private Consortia

Historically, the oil and gas industry has used collaboration initiatives, such as Deepstar, to foster innovation in deepwater reservoirs (Deepstar, 2021). Initiated in 1991, and until recently administered by Chevron, Deepstar managed a project portfolio intended to reduce costs and risks associated with producing oil and gas from deepwater reservoirs. Geothermal innovation similarly requires the convergence of disciplines across subsurface, surface, and digital domains, as well as power markets, grid infrastructure, and other emerging areas of technology that are less familiar to the oil and gas industry. Additionally, compared with deepwater drilling, social acceptance has moved from a rig hundreds of miles offshore, to a technology that may be located in view of someone’s backyard, building a marked contrast in social engagement needs. Oil and gas industry perspectives about working within private consortia are considered in detail in Chapter 6, Oil and Gas Industry Engagement in Geothermal.
B. Public Private Partnerships

As discussed in further detail in Chapter 12, Policy, Advocacy, and Regulatory Considerations in Texas of this Report, the State of Texas has a history of novel private-public partnerships. For example, the NASA/Space-X partnership successfully increased efficiencies, and drove new innovations in a mature technology sector (Maney, 2015). For the public sector, these partnerships are key to driving efficiency gains, reducing life-cycle costs, and transferring risks. For the private sector, they can provide enhanced return on investment, help gain competitive advantages, and identify new resource or value streams. In the case of Space-X, the technologies needed to effectively and efficiently explore for geothermal bare strong resemblance to technologies needed to explore space or the deepest areas of our oceans. Knowledge and key actors may reside in enterprises such as NASA, the U.S. National Laboratories, or by bridging across to other sciences and art in order to create the connections and generate value needed. The subject of technology transfer between space, defense and geothermal is explored in depth in Chapter 8, Other Strategic Considerations for Geothermal in Texas of this Report.

VIII. Conclusion

The oil and gas industry, particularly in Texas with its rich history in energy leadership, assets, resources, friendly policy environment, and social acceptance of subsurface energy production, could play a critical role in enabling efficiency gains, lowering costs, and demonstrating key elements of geothermal technologies. Next generation geothermal concepts need to prove that they can expand into sedimentary basins to create larger market opportunities, with a roadmap to achieve competitive economics. To achieve this, the geothermal and oil and gas industries should support innovative demonstration projects through direct investment, and using current assets (e.g., seismic and well data, wells, leases, and people). Government, both State and Federal, in turn, can incentivize geothermal projects by insuring or covering a part of drilling costs or by providing grants or concessional loans for first of a kind geothermal projects.

This support could accelerate oil and gas learnings spillover, drive project cost reductions of around five to ten percent, and enable additional economies of scale cost reductions of eight to 30 percent (and perhaps up to 50 percent in some cases). R&D support for benchtop and field trials is also essential to boost innovation and market potential. Industry organizations can enable faster dissemination of best practices, lessons learned, and the development of standards to allow communication of key project parameters and risks to stakeholders. Critical to all elements are new collaboration models for geothermal to enable cross-sector innovation, and increase public awareness to support social acceptance and market demand.
Conflict of Interest Disclosure

Rebecca Schulz serves as an energy and investment consultant on the World Energy Outlook team seconded from Shell to the International Energy Agency in Paris, France, and is compensated for this work. She further serves a non-compensated role as the founding chairperson of the Society of Petroleum Engineers Geothermal Technical Section. Outside of these roles, Rebecca Schulz certifies that she has no affiliations, including board memberships, stock ownership and/or equity interest, in any organization or entity with a financial interest in the contents of this manuscript, and has no personal or familial relationship with anyone having such an affiliation or financial interest.

Silviu Livescu serves as a faculty member in the Petroleum and Geosystems Engineering Department and a co-principal investigator for the HotRock Industry Affiliates Program, both at the University of Texas at Austin, and is compensated for this work. He is also a co-founder of Bedrock Energy, a geothermal heating and cooling startup, and the editor-in-chief of Elsevier’s Geoenergy Science and Engineering. Outside of these roles, Silviu Livescu certifies that he has no affiliations, including board memberships, stock ownership and/or equity interest, in any organization or entity with a financial interest in the contents of this manuscript, and has no personal or familial relationship with anyone having such an affiliation or financial interest.
Chapter 5 References


Chapter 5 Appendix A

The authors of the Future of Geothermal Energy in Texas report are grateful for the participation and insight provided by the following individuals. Thank you for taking the time to share your knowledge and experiences about the learning spillover effects from the oil and gas industry to the geothermal industry that will impact Texas and the globe. Data collected from all participants has been aggregated and anonymized to capture and disseminate trends, views, and perspectives.

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• Marit Brommer, Executive Director, International Geothermal Association
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• John Clegg, Chief Technology Officer, Hephae Technology
• Lance Cook, Chief Technology Officer, Sage Geosystems
• Rik Brooymans, Technical Integrated Projects Manager, CGG
• Roland Horne, Professor, Stanford University
• Lev Ring, President, Sage GeoSystems
• Ellie Maclnnes, Head of Geothermal, CGG
• Jordan Nielsen, Engineer, Southwest Research Institute
• Anoop Poddar, Senior Partner, EV Private Equity
• Vikram Rao, Executive Director, Research Triangle Energy Consortium
• Jody Robins, (former) Project Development Manager, National Renewable Laboratory
• Mukul Sharma, Professor of Petroleum Engineering, University of Texas, Austin
• Cindy Taff, Chief Executive Officer, Sage Geosystems
• Jeroen van Duin, General Manager Geothermal, Shell
• Eric van Oort, Professor of Petroleum Engineering, University of Texas, Austin
Transferable practices, technologies, assets and ways of working

Each project phase is segmented into learning types, broken into applicable petroleum technology, practices or assets, and assigned a potential learning cost reduction parameter that varies for a given geothermal technology based on applicability (Table 5.4). We estimate the range of cost reduction that could be realized for each technology, practice or asset based on existing literature and industry interviews. A range (low-medium-high) was developed for each element based on potentially achievable learning. Not all technologies have been assessed. Additional technologies may play important roles in the future. Alternatively, others may not reach the full potential described.

Table 5.4. Technologies, practices and assets characterized and used to assess geothermal learning curve potentials. Source: Future of Geothermal Energy in Texas, 2023

<table>
<thead>
<tr>
<th>Type of Learning</th>
<th>Project Phase</th>
<th>Technology, Practice, or Asset</th>
<th>Cost or productivity improvement range</th>
<th>CHS Low</th>
<th>CHS Mid</th>
<th>CHS High</th>
<th>DHCS Low</th>
<th>DHCS Mid</th>
<th>DHCS High</th>
<th>EGS Low</th>
<th>EGS Mid</th>
<th>EGS High</th>
<th>CLGS Low</th>
<th>CLGS Mid</th>
<th>CLGS High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and Gas Spillover</td>
<td>Pre-Development</td>
<td>Basin modeling</td>
<td>0 to 70%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>20%</td>
<td>40%</td>
<td>70%</td>
<td>0%</td>
<td>30%</td>
<td>50%</td>
<td>0%</td>
<td>30%</td>
<td>70%</td>
</tr>
<tr>
<td>Oil and Gas Spillover</td>
<td>Pre-Development</td>
<td>Existing wells and data (well logs, seismic, reports, core)</td>
<td>5%</td>
<td>8%</td>
<td>10%</td>
<td>5%</td>
<td>10%</td>
<td>19%</td>
<td>5%</td>
<td>10%</td>
<td>19%</td>
<td>5%</td>
<td>10%</td>
<td>19%</td>
<td></td>
</tr>
<tr>
<td>Oil and Gas Spillover</td>
<td>Drilling</td>
<td>Drilling efficiency processes</td>
<td>5 to 19%</td>
<td>5%</td>
<td>8%</td>
<td>10%</td>
<td>5%</td>
<td>8%</td>
<td>12%</td>
<td>5%</td>
<td>8%</td>
<td>12%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>Oil and Gas Spillover</td>
<td>Drilling</td>
<td>Measuring While Drilling (&lt;200 degC)</td>
<td>5 to 12%</td>
<td>5%</td>
<td>8%</td>
<td>12%</td>
<td>5%</td>
<td>8%</td>
<td>12%</td>
<td>5%</td>
<td>8%</td>
<td>12%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>Oil and Gas Spillover</td>
<td>Drilling</td>
<td>Directional well-drilling</td>
<td>10 to 20%</td>
<td>10%</td>
<td>15%</td>
<td>20%</td>
<td>10%</td>
<td>15%</td>
<td>20%</td>
<td>10%</td>
<td>15%</td>
<td>20%</td>
<td>0%</td>
<td>5%</td>
<td>10%</td>
</tr>
<tr>
<td>Oil and Gas Spillover</td>
<td>Drilling</td>
<td>Horizontal well-drilling</td>
<td>10 to 20%</td>
<td>10%</td>
<td>15%</td>
<td>20%</td>
<td>10%</td>
<td>15%</td>
<td>20%</td>
<td>10%</td>
<td>15%</td>
<td>20%</td>
<td>0%</td>
<td>5%</td>
<td>10%</td>
</tr>
<tr>
<td>Oil and Gas Spillover</td>
<td>Drilling</td>
<td>Multi-lateral wells</td>
<td>Not characterized</td>
<td>Not characterized</td>
<td>Not characterized</td>
<td>Not characterized</td>
<td>Not characterized</td>
<td>Not characterized</td>
<td>Not characterized</td>
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<td>Not characterized</td>
<td>Not characterized</td>
<td>Not characterized</td>
<td>Not characterized</td>
<td></td>
</tr>
<tr>
<td>Oil and Gas Spillover</td>
<td>Completions</td>
<td>Hydraulic fracturing</td>
<td>0 to 40%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>15%</td>
<td>40%</td>
<td>0%</td>
<td>10%</td>
<td>15%</td>
</tr>
<tr>
<td>Oil and Gas Spillover</td>
<td>Completions</td>
<td>Multi-zone completions: Plug and perforate, sliding sleeves</td>
<td>0 to 30%</td>
<td>0%</td>
<td>5%</td>
<td>10%</td>
<td>5%</td>
<td>15%</td>
<td>30%</td>
<td>5%</td>
<td>20%</td>
<td>30%</td>
<td>5%</td>
<td>20%</td>
<td>30%</td>
</tr>
<tr>
<td>Economies of Scale</td>
<td>Development Well Costs</td>
<td>Multi-well pad designs</td>
<td>0 to 20%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>5%</td>
<td>10%</td>
<td>20%</td>
<td>5%</td>
<td>10%</td>
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<tr>
<td>Economies of Scale</td>
<td>Completions</td>
<td>Zipper frac operations</td>
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<td>Economies of Scale</td>
<td>Completions</td>
<td>Wellbore clean-out/ drill out</td>
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<td>Economies of Scale</td>
<td>Power plant &amp; Steam gathering system</td>
<td>Modular or replication-focused developments</td>
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Table 5.4. (Continued)

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<td>Advanced turbinworking fluids, e.g. supercritical CO2; other</td>
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