committing to the *drill bit*

derisking enhanced geothermal's unique market structure

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Executive summary

Proponents of enhanced geothermal energy are correct that this nascent technology has incredible potential to decarbonize the U.S. energy system. Enhanced geothermal systems (EGS) share drilling technologies with the shale fracking industry, making them a compelling option for policymakers looking to leverage existing American supply chains to drive decarbonization at scale. But the market structures of these two sectors differ significantly. Policymakers interested in supporting rapid EGS deployment should understand these distinctions and respond appropriately rather than expecting a geothermal boom to emerge spontaneously simply because EGS projects rely on an already-proven technology suite.

The key differences between EGS projects and shale fracking include:

- **Proven reserve discovery:** Unlike shale drillers, which can easily identify and monetize proven reserves, EGS developers currently struggle to credibly demonstrate at scale that heat extraction rates won't decline over time, hindering their access to project finance at scale.

- **Different business models and financing structures:** While fracking was primarily a land speculation business where wildcatters made money through land appreciation rather than through exclusive access to technology, EGS developers are likely to remain owner-operators of power infrastructure, with a different relationship to both drilling rights and to their unique and proprietary drilling technologies.

- **Market structure disparities:** Shale drillers sell into global commodity markets with high liquidity, while EGS serves electricity markets characterized by regional fragmentation and long-term power purchase agreements. EGS projects more closely resemble gas power plants in their business and risk profile than they do gas suppliers; in other words, EGS projects are infrastructure investments generating stable long-term cash flows over decades, not commodity speculation plays, which profit from price volatility.

- **Legal and financial infrastructure gaps:** The fracking boom benefited from tax credits, specialized accounting methods, cash-and-carry agreements, and permissive land lease terms that aren't yet adapted for the EGS sector.

To accelerate EGS deployment, policymakers should pursue four key strategies:

- **Derisk heat resource exploration:** Replicate the Department of Energy's FORGE test site across the country to create "derisked basins" and develop mechanisms to mitigate flow test drilling risks.

- **Enhance project finance and offtake support:** Provide short-duration term loans to establish cash flow history for other institutional investors, create "pre-payment" structures analogous to cash-and-carry contracts to support upfront capital expenditure, and establish offtake warehousing facilities to support PPA liquidity and project creditworthiness.

- **Expand long-distance transmission capacity:** Build out grid infrastructure to create more liquid electricity markets to reduce dependence on corporate PPA buyers.

- **Promote technology diffusion:** Support research consortia and standardization of project development procedures to lower costs and facilitate knowledge-sharing.

For enhanced geothermal energy to become a keystone component of America's clean energy portfolio, policymakers must deliberately build the legal, financial, and market infrastructures needed for its success. Policymakers must recognize that EGS projects are infrastructure investments that require patient capital and policy certainty in order for the sector to reach its full potential.

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I. Introduction

Geothermal energy has the potential to substantially contribute to addressing the United States' energy demand and decarbonization challenges. The economics are sound: Various credible models, and CPE's own modeling, suggest that deploying an enhanced geothermal system (EGS) is far cheaper than new nuclear energy or even offshore wind, and it provides a source of clean, firm energy that can meet 24/7 demand from industrial and manufacturing customers.[1] But the real enthusiasm around EGS comes from the simple fact that the technology it relies on directly leverages the unconventional oil and gas drilling innovations of the fracking boom.

Enhanced geothermal projects use a set of unconventional oil and gas drilling technologies, including directional drilling and hydraulic fracturing, that are technologically derisked and should not take much time to deploy. And unlike, say, nuclear energy, geothermal drilling boasts a viable supply chain to boot: the CEO of Fervo, a leading EGS developer, described being able to call up drill bit manufacturers in the oil and gas sector to secure customized geothermal-appropriate components as if it weren't much hassle.[2] Proponents of EGS also highlight that geothermal energy development can draw in workers from the oil and gas industry who have already been trained and whose skills are easily applied to geothermal energy. These narrative hooks anchor arguments praising the technology's potential.

It's not hard to see why geothermal is gathering steam: A uniquely American technology which—entirely factually—both undergirds the country's most polluting sectors yet represents the country's claim to "energy dominance," has a real chance at becoming the *solution* to America's decarbonization and energy demand challenges.[3]

The boosters are not wrong about the potential of EGS technology. In fact, none of the public evidence surrounding geothermal systems suggests that they don't work as advertised by geothermal developers. However, the enthusiastic comparisons between the world-historical success of the American oil and gas industry and the potential success of American EGS obscure important differences in the market structures of the two sectors. The American shale fracking boom occurred under extremely particular *financial* conditions that EGS does not replicate.

Put simply: EGS is not fracking. While policymakers' understanding of the innovation policy ecosystem that enhanced geothermal energy requires has evolved considerably over the past few years, not enough attention has been paid to laying the legal and financial groundwork for its widespread deployment. Policymakers and advocates hoping for another great fracking boom,

[1] See the following sources: Lala (2025); National Renewable Energy Laboratory (2024); Ricks et al. (2024); U.S. Department of Energy (2025); Lazard (2024).
[2] Roberts (2025) and Sagatelova and Fitzpatrick (2024).
[3] From Cipher News: "'The U.S. has a number of different superpowers and putting holes in the ground and taking things out of those holes is one of them—and doing so more economically and more efficiently than basically any other place on Earth,' said Drew Nelson, vice president of Project InnerSpace." See: Clifford (2025).

this time with the clean energy of enhanced geothermal, are implicitly assuming that the same economic and financial conditions that drove the shale boom of the late 2000s and early 2010s can be replicated in the enhanced geothermal sector by virtue of its technological profile. But, for the most part, they can't.

To decarbonize our very American predisposition to "drill, baby, drill," policymakers should be aware of how the financial contours of the shale boom are different from those of EGS project development. Enhanced geothermal power projects not only exist within a particular market structure, but require a different set of financial supports from policymakers and advocates to realize their potential as a keystone national energy resource.

Table 1. Market structure comparison

Market structure component	Shale fracking	Enhanced geothermal	
Timeline	approx. 2008-15	**Status-quo outlook (current)**	**Medium-term outlook (ideal)**
Source of inherent value	Land / drilling rights	Technology and land	"Derisked basin" that produces power over the long term
Land lease market	Liquid	Tepid	Liquid
Market-shaping actor	Wildcatters	Startups	Owner-operators
Offtake market structure	Liquid global commodity market • Short-term price hedging • Limited duration risk	Smaller corporate PPA market • Less liquid • Duration risk	Expansive PPA market • More liquid* • Duration risk
Price-maker or price-taker?**	Marginal price-setter	Price-taker relative to solar, batteries, and peaker gas	Price-taker relative to solar, batteries, and peaker gas
Construction timeline	1-2 years • "Short-cycle" • Low duration risk	5+ years*** • Power station input delays • Higher duration risk	2-5 years • Supply chain stability • Lower duration risk
Does demand drive supply?	Yes	Not yet	Yes, in "derisked basins"
Interest rates	Low	High	n/a

** requires policy support, including but not limited to greater transmission and battery storage buildout, in order to smooth price volatility*
*** for geothermal, applies only to "deregulated" electricity markets where independent power producers bid into an RTO/ISO's wholesale market*
**** not including time required for resource assessment*

II. Fueling a Productive Bubble: A short history of the shale boom

In this paper, fracking refers broadly to the "unconventional" hydraulic fracturing and horizontal drilling techniques that oil and gas developers use to extract crude oil and natural gas from shale basins across the country. While oil drillers have experimented with fracking-style drilling as early as the 1920s, policy-supported exploration of unconventional shale gas fields and slick-water fracturing experimentation really only began in the late 1970s, bore fruit by the end of the 1990s, and led to an economic explosion in the 2000s and early 2010s—perhaps just when the U.S. economy needed it most, during a period of high energy prices and concerns about domestic oil and gas scarcity.

Fracking directly and indirectly contributed to as much as 10 percent of U.S. GDP growth between 2010 and 2015.[4] And, in the past two decades, the U.S. became the world's largest producer first of gas, then of oil—and a net exporter, too.

John Golden and Hannah Wiseman summarize the scale of the shale gas boom:

> *"But in half that time—the ten years from 1998 to 2007—shale gas production more than quintupled again, rising from nearly 400bcf [billion cubic feet] to nearly 2tcf [trillion cubic feet]. Within a mere five additional years, United States' shale gas production had quintupled a third time. Production in 2012 amounted to more than 10 Tcf, more than five times the production level in 2007 and about ten times the amount that the National Research Council had [in 2001] projected for 2020. From 2000 to 2012, shale gas had gone from supplying only about 1% of the United States' natural gas to supplying well over one-fourth."*[5]

[4] Yücel and Plante (2017).
[5] Golden and Wiseman (2015).

The fracking boom unlocked both gas and oil production

Baker Hughes Weekly Rotary Rig Count (North America, Oil and Gas)

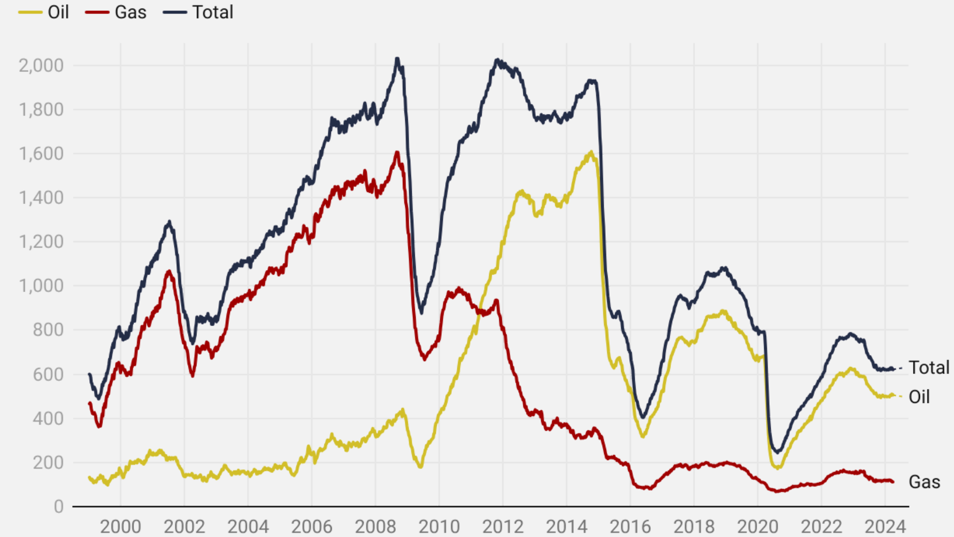

Chart: Center for Public Enterprise • Source: Baker Hughes

Oil and gas well drilling

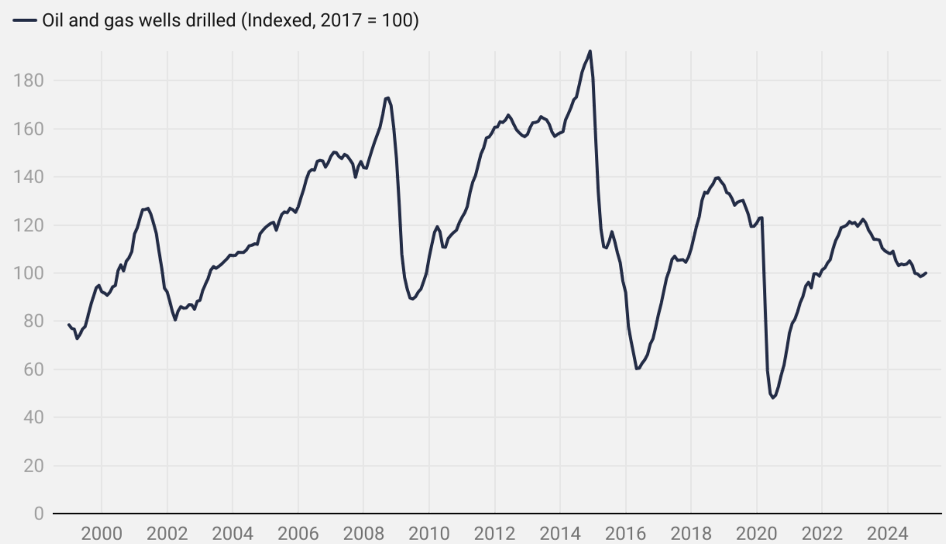

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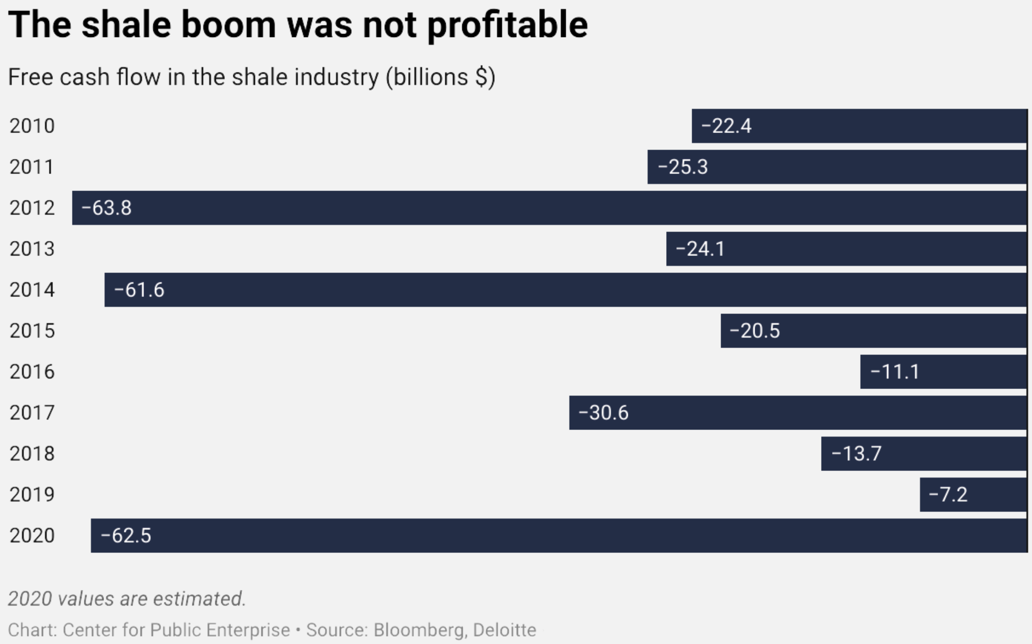
Chart: Center for Public Enterprise • Source: Federal Reserve Economic Data

The multi-decade development of the suite of technologies and techniques that brought fracking to market dominance is one of the great success stories of patient innovation policy in recent U.S. history. Analysts at Employ America, RFF, and the Breakthrough Institute have all emphasized that this (literally) groundbreaking innovation required decades of federal and state policy support to achieve mass uptake and commercial profitability.[6] This very valuable analysis has focused on drawing best practices from the shale story and applying it toward innovation policy, particularly toward emerging energy sources like enhanced geothermal power. However, less attention has been paid to how the unique technological properties of the shale fracking sector and its associated market structure cultivated a shale boom.

Indeed, one less-appreciated aspect of the 2010s shale boom is that its massive impact on the U.S. economy actually came from how it laid the groundwork for a future shale bust. From a financial perspective, the investment figures almost defy belief. Between 2010 and 2020, U.S. oil and gas companies saw over $342 *billion* in losses.[7] IEEFA estimates that, in that same time frame, North American shale oil and gas developers had over $189 billion in negative free cash flow (the difference between their cash flow from operations and their total capital expenditure).[8] Between the financial crisis and the pandemic, large institutional investors piled into the shale sector, driving capital expenditure seemingly without regard for long-term solvency. Between 2015 and 2019, the sector yielded $207 billion of losses to debt holders in formal bankruptcy proceedings alone.[9] This figure does not account for the losses to equity shareholders, or for losses resolved outside of formal bankruptcy procedures. Indeed, the shale boom was a perfect example of what Bill Janeway describes as a "productive bubble," in which investors rush toward speculative investments that, even if their value collapses, transform the structure of the economy.[10]

[6] Datta and Amarnath (2023); Wang and Krupnick (2013); Trembath et al. (2012).
[7] Wethe and Crowley (2020).
[8] Williams-Derry et al. (2020).
[9] Wethe and Crowley (2020).
[10] Janeway (2021).



The shale boom was a massive transfer of money from large lenders to U.S. households.[11] Thanks to lower extraction costs for and greater production of oil and gas, households saved an average of 14 percent on the use of refined petroleum fuel products per year between 2008 and 2015, driving up household purchasing power.[12] One study estimated that shale-driven price decreases added as much as $1,200 to the average household's annual purchasing power, representing $163 billion in economic stimulus to other sectors.[13]

To be sure, the subsequent shale bust devastated the communities and workers who depended on the industry. But its macroeconomic effects likely would have been worse had it not occurred during a period of strong economic growth in other sectors.[14] The same features that created a highly competitive ecosystem of small wildcat drillers helped spread the damage enough such that the shale bust never posed a systemic risk to the economy comparable to the 2008 real estate crash or the end of the 2001 dotcom bubble.

Policymakers' and investors' hopes for EGS are often anchored on the precedent set by shale fracking's incredible success: If only clean energy—or, really, any critical infrastructure—could follow the path of the shale boom. However, CPE believes that there are critical differences between the sectors that will lead EGS down a very different path from that of shale fracking. If

[11] The long-term fixed capital investments into unconventional oil and gas drilling infrastructure were financed on the balance sheets of entities with low marginal propensities to consume, such as banks, with the benefits going to entities with a high marginal propensity to consume, such as households.
[12] Yücel and Plante (2017).
[13] Perry (2013).
[14] Federal Housing Finance Agency (2016). Raimi et al. (2025).

we are truly to tap this vital technology's potential, policymakers must understand how its market structure differs from the one that fueled the shale boom.

III. Enhanced geothermal is not like fracking

The many explicit technical similarities between shale fracking and EGS projects augur a bright future for EGS, including a rapid learning curve and straightforward transfers of existing skills for workers trained in the oil and gas sector. However, despite EGS's promise as a clean firm energy technology, its underlying economics are drastically different from fracking. If policy does not grapple with why that's the case, then, not only might we not get the geothermal boom we're seeking—we may not get one at all.

One reason the fracking boom and subsequent bust seemed so macroeconomically benign was the sector's composition. Instead of being dominated from an early stage by large firms, many small independent drillers, or "wildcatters," also participated in drilling. This is not to say that large players did not have significant market share, especially in upstream services. However, the prevalence of wildcat drillers in the upstream portion of the oil and gas value chain drove a highly competitive industry where individual oil and gas producers had less pricing power vis-a-vis their consumers than larger firms did.[15]

Moreover, lenders assumed they would be protected against downside default risks by keeping diversified books of smaller-ticket loans to many wildcatters. These loans were themselves easily dischargeable in bankruptcy, insofar as they were secured on a project finance basis: While lenders had only limited recourse to the assets of the project developer entity or partnership, they could seize drilling assets and the associated land rights and resell them. If one wildcatter's project went bust, another could buy the land and take its place.

We believe that these fast-churning conditions underlying the fracking boom will not be replicated in the enhanced geothermal sector. There are several critical differences between two sectors, including the following:

- Developers of both shale resources and EGS systems capture equity value from their land purchases and leases through measurements of "**proven reserves**" of fossil fuels and heat, respectively, and can borrow against them. EGS projects, however, still need to credibly prove at scale that the heat extraction rate of their geothermal wells will not decline over time—but it's not clear what standard of proof investors require in order to provide project finance.

[15] Gevorkyan and Semmler (2015).

- Shale fracking was first and foremost a **land speculation business**. First movers in the shale industry made their money not specifically from their unique technology, or even from simply selling oil and gas, but rather from purchasing drilling rights and speculating on land value appreciation as commodity prices rose. Even if first-mover EGS developers can monetize the value of their proven reserves of heat to drive the growth of a more liquid land lease market, they are likely to remain owner-operators of their power stations over the medium-term, potentially constraining the pace of project deployment relative to that of the fracking sector's ecosystem of competitive low-margin wildcat drillers.

- Oil and gas markets are **markets for commodities. EGS, on the other hand, services the electricity generation market**, which, despite possessing many commodity market-like features, remains unusual and regionally bespoke: Due to the physical requirements of the electrical grid and its current inability to store or move electrons at scale over long periods or over long distances, clean electricity generation is largely supplied via long-term power purchase agreements. Shale drillers, on the other hand, sell into markets with global liquidity facilitated by the ability of third parties to more freely speculate on oil price. In short, EGS' business and risk profile looks more like that of a gas power plant than of its gas supplier.

- The boom in shale fracking capital expenditure was undergirded not just by cheap debt and a liquid, commoditized offtake market, but by a **uniquely permissive legal and financial infrastructure**—tax credits, accounting sleights of hand, cash-and-carry agreements, and special land lease terms—that incentivized overproduction in ways that might not be immediately replicable in the nascent EGS sector. These qualities are, of course, a double-edged sword: the lack of this infrastructure mitigates uneconomic activity from the point of view of lenders and many developers, yet that lack also militates against EGS ever replicating the high levels of investment, rapid cost decreases, and consumer benefits of the shale boom without sector-specific policy action.

The remainder of this report drills deeper into these factors to build a comparative analysis of the market structures of the shale fracking sector and the nascent EGS sector.

This report uses "shale fracking" as a catch-all synecdoche for the broader unconventional oil and gas drilling sector. While firms in the sector prefer to use the words "frac" and "fraccing," given their direct lexical relationship to the hydraulic fracturing process they're describing, most writing outside the industry—including in journalism, banking, consulting, and policymaking—uses "frack" and "fracking."[16] We stick to this latter convention due to its widespread uptake across peer research, journalistic, and market-advisory institutions.

For ease of analysis, this report does not contrast shale gas fracking and shale oil fracking. While this decision smooths over meaningful distinctions between each one's extraction process and commodity market structure, we believe it is more helpful for the purposes of this report to consider the shale fracking sector as a whole when juxtaposing it against enhanced geothermal energy.

Our research is drawn from news sources, academic research, policy work, and some off-the-record interviews with experts in both sectors. This cross-sector juxtaposition illuminates the different kinds of policy and financial support that rapid EGS deployment actually requires, consistent with our previous work on project finance and clean firm energy deployment. We conclude that any push to scale up EGS across the country requires policymakers to treat geothermal power for what it is: not a speculative commodity market bet, but an infrastructure project deserving of patient capital.

[16] The use of "frack" and "fracking" comports comfortably with American English spelling conventions (e.g., "picnic" turns into "picnicking"). But its spelling and pronunciation also make it easy for critics to pun off the word to highlight the sector's negative environmental impacts.

IV. Proven reserves: Hot rocks... or hot air?

While it is easy for shale drillers to find underground reserves of oil and gas, it is not yet easy for EGS developers to do the same at scale.

Shale fracking

Shale drilling companies measure their "proven reserves" as the amount of oil or gas they expect to reasonably extract from the land they own or lease. Drillers must pay upfront to explore shale deposits to quantify their proven reserves and to borrow against them; they pay upfront not just for exploration itself but to purchase access to these reserves via sales and leases. In other words, borrowing against proven reserves helped further monetize and draw value from their land leases.[17]

There are international standards for how oil and gas drillers must measure and calculate proven reserves—which are any reserves of oil and gas that have greater than a 90 percent likelihood of being extracted given a driller's technology profile and current market prices.[18] If market prices rise or drilling technology becomes more efficient, the amount of proven reserves the company can claim will increase—insofar as some of the resources in the next category of reserves, the "probable reserves," become easier to extract.

Crucially, for our purposes, the value of proven reserves serves as the basis for oil and gas companies' equity valuations, against which they raise debt to finance their capital expenditure into drilling wells. Oil and gas companies thus have a clear interest in maximizing their access to reserves and increasing drilling efficiency in order to augment their proven reserves, boost their equity valuations, and access capital markets.

While exploration has always been one of the most difficult and expensive activities undertaken in the oil and gas business, advances in remote imaging and computing have driven long-term productivity improvements.[19] These techniques, while costly, justify themselves on grounds of scalability and efficiency. The high entry costs of these innovations likely spurred consolidation in the broader oil and gas industry, especially in downstream oil services firms and the major oil companies that offer those services themselves, before the 1990s.[20] However, thanks to a combination of luck and public policy, these techniques actually helped create the disintegrated downstream structure that enabled the fracking boom: Mitchell and other first movers began to rapidly explore reserves at a lower cost, thanks both to advances in general industry technology such as 3D seismic imagery and to fracking-specific techniques such as micro-seismic imaging

[17] This argument draws broadly on the work of Henry George on the economics of land valuation.
[18] Maverick (2022) and Chen (2022).
[19] Bohi (1998) and Bondar (2021).
[20] Voola (2006).

developed in collaboration with the DOE.[21] Over the late 1990s, these advances helped Mitchell develop and raise the value of its land holdings.

The subsequent commercialization of fracking technology during the 2000s commodity supercycle of high and climbing oil and gas prices thus set off a scramble for "proven reserves" across the country's major shale basins. Land speculators, large energy companies, and smaller "wildcat" drillers all sought to make it big by betting that fracking could make both accessible and harder-to-reach shale deposits more commercially viable. Privately held drilling companies, which had to pledge their proven reserves as collateral to secure loans, were more likely to frack "frontier" wells with harder-to-reach deposits, while publicly listed companies, which could capitalize their proven reserves as equity valuations on the stock market, could pursue economies of scale and cost savings through "pad drilling" in more developed shale fields.[22]

These drillers secured debt for these capital investments through various types of "project finance" agreements, in which creditors lend to finance a specific venture sponsored by a developer or group of developers, and have no recourse or limited recourse to the other assets owned by the sponsoring entities.[23] Borrowers prefer project finance structures for capital-intensive projects not just because they protect their balance sheets in event of a bankruptcy, but because they do not require the owners or sponsors to dilute the value of their equity by issuing more shares to fund each new project. Not only was the shale boom driven by these kinds of project finance structures, but the lenders to many of these development partnerships were often banks, rather than either higher-cost sources of credit such as private equity/credit or lower-cost venture capital, which is not usually part of project finance transactions.

Of course, with the boom came the bust. There are two ways the value of proven reserves can fall—first, through a fall in the price of the resource being extracted, and, second, through a decline in the reserve's quantity of commercially extractable resources. The latter is unavoidable: Capital expenditure undertaken to extract oil and gas reduces developers' proven reserves and therefore their equity valuations, too.[24] Managing this "decline rate" and finding new reserves are a significant part of how drillers stay solvent. But the former turned out to be the bigger threat. The rush for proven reserves enabled a massive supply glut—first in gas, then in oil—that, by the mid-2010s, ended up forcing prices down to such an extent that many of those firms' proven reserves now appeared worthless. When oil prices started falling after 2014, due to this glut as well as to production increases in OPEC countries, bankruptcies skyrocketed across the oil industry: Insofar as the value of the drillers' proven reserves went into a tailspin, many of those firms no longer had sufficient collateral to maintain lines of credit with banks for further

[21] Wang and Krupnick (2013).
[22] Liu et al. (2019).
[23] Croft and Dewar (2023).
[24] Lopez and Crowe (2015).

debt-financed capital expenditure.[25] (Those banks contained those losses by shifting underwriting practices to prioritize already-explored reserves with proven capacity rather than more speculative exploration.[26])

Enhanced geothermal

For their part, EGS developers are also looking to maximize the value of their proven reserves, although of underground heat rather than of shale resources. Insofar as they are transforming heat reserves into electricity that has a market value through their unique technologies, EGS developers sometimes refer to their proven reserves as "beneficially owned megawatts." The value proposition of EGS firms rests in their ability to generate and monetize these beneficially owned megawatts by deploying their unique technology.

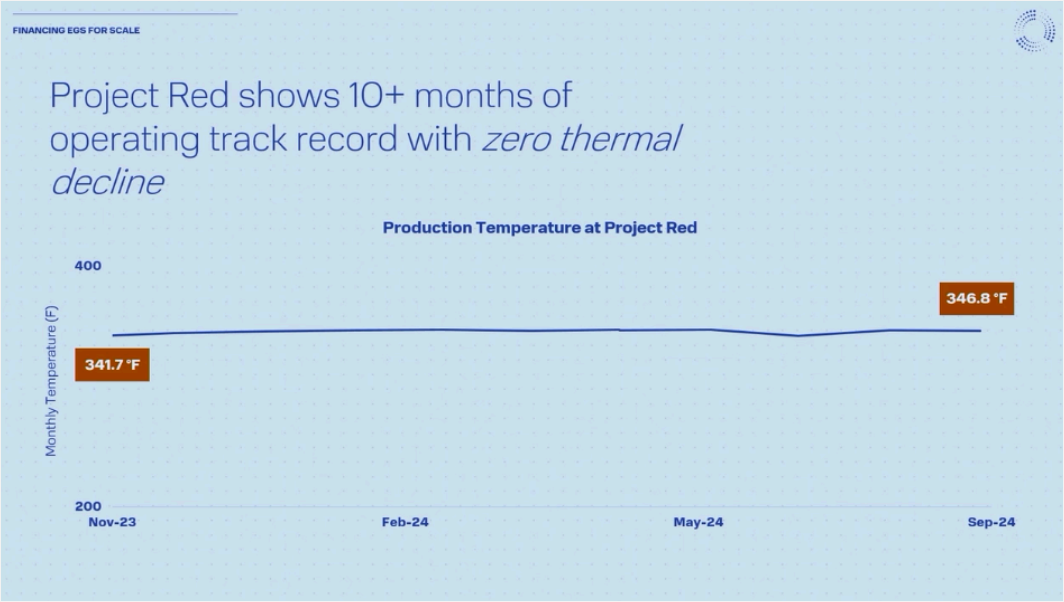
However, leading EGS developers have consistently reported that they are starving for project finance and low-cost debt while they are simultaneously inundated with demand for company equity. The fact that Fervo, a leading EGS developer, is preparing for an IPO next year suggests that the company is more able to reap investors' interest in its particular EGS technology, the darling of venture capital investment over the past few years, rather than specifically capitalizing on the value of, say, the land it owns, or even its eventual electricity generation capacity.[27]

There is some evidence that lenders are interested in providing project finance—though our sample size remains extremely small. The first publicly announced project finance bridge loan for a full-scale EGS project was only last year, when XCaliber Rural Finance provided a construction loan to Fervo's Cape Station project underwritten by the electricity-generating potential of the proven heat reserves at Cape Station. Our research suggests, however, that this loan is not yet replicable without significant policy support for heat reserve discovery and flow test drilling.

Fervo and other EGS developers argue that their estimates of beneficially owned megawatts are more reliable than proven reserves of oil and gas: Fracking depletes proven oil and gas reserves while heat extraction does not seem to deplete the commercially extractable quantity of a heat resource. In other words, the quantity of their proven heat reserves is stable—and can be treated as collateral and borrowed against to finance its extraction as geothermal energy. This is one potential advantage that enhanced geothermal power has over shale oil and gas. However, Fervo has only proved itself at pilot-scale. Its Cape Station project is expected to have a nameplate capacity of 500 MW, two orders of magnitude larger than Project Red.[28] Investors, especially longer-term debt investors, are likely still uncomfortable about enhanced geothermal projects'

[25] DiChristopher (2016).
[26] Wells that have already been explored but have not been fully tapped have an embedded option in them that makes exploration for new wells less valuable. This report will discuss the idea of wells as "options" in subsequent sections. See: Azar (2017).
[27] Geman and Neuhauser (2025).
[28] Fervo Energy (2025).

ability to maintain minimal heat decline rates at that scale—and over a 20-to-30-year time frame, no less.



Identifying proven reserves of underground heat still faces *technical* barriers that remain hard to surmount. While the Department of Energy, US Geological Survey, and InnerSpace have built maps predicting where likely underground heat reserves are located,[29] these maps do not yet pinpoint confirmed sources of underground heat. Although these maps reveal that states outside the Mountain West region of the country have the potential for EGS projects, they are not precise enough for debt investors to trust or base their lending decisions on. And, while there are some remote sensing technologies available to the EGS sector, they remain less precise than those deployed in unconventional oil and gas drilling—and might require direct, non-remote confirmation of heat resources for the foreseeable future. Over the medium-term, however, EGS developers will still need to drill flow test wells to measure heat decline rates, and investors will have to develop underwriting standards around these measurements.[30]

Policymakers interested in supporting enhanced geothermal power must therefore ensure that EGS developers operate their projects in a "derisked basin" where all wells drilled have stable and predictable heat rates such that developers can maintain well fractures at constant temperatures for years. This is already the value-add of the Department of Energy's FORGE test site for enhanced geothermal drilling in Utah:[31] By proving the commercial viability of underground heat reserves in Beaver County, Utah, FORGE allows developers like Fervo to set up successful

[29] Walton (2024); Project Innerspace (2025); U.S. Geological Survey (2022).
[30] Arun (2024a).
[31] U.S. Department of Energy; Ough (2025).

projects like Cape Station on adjacent land plots and socializes among investors a more accurate technological risk profile for enhanced geothermal projects across that particular "basin" location. Setting up more research collaborations like FORGE across the country and derisking flow test drilling at those new locations would both speed up project development and familiarize longer-term investors with geothermal risk profiles across newer geographies. This kind of policymaker support deployed at scale to create multiple "derisked basin" sites across the country would unlock EGS developers' ability to borrow against the value of proven reserves and their power-producing potential from far more lenders than are currently interested.

More than anything else, EGS developers' lack of easy access to project finance will constrain their pace of project development and thereby constrain much of the potential for "learning by doing" in the enhanced geothermal sector.[32] But, as this report will discuss further below, facilitating geothermal exploration and derisking flow test drilling will not sufficiently address other barriers to creating a competitive, fracking boom-style market among EGS developers. Creating "derisked basins" only breaks the first logjam in the project finance bottleneck; EGS developers have more hurdles to clear.

[32] Our analysis here is rooted not just in industry research but in the economic theories concerning the relationship between market structures and interest rates. We judge that the various market actors engaging in the enhanced geothermal sector—financiers, developers, venture capitalists, and policymakers—do not have comparable valuations for this nascent technology asset. In isolation, each actor sets that asset's valuation at the price of the liquidity required to clear its liabilities/obligations from holding such an asset. There is no single intersecting interest rate at which these market actors would necessarily agree to co-finance an emerging technology like an EGS project absent a set of institutions that mediate markets to make them comparable by allowing investors and developers to reach "consensus conventions." Put another way, interest rates are invented for purpose. Zooming out, the value of an enhanced geothermal project is intrinsic and is set self-referentially to what market actors acting socially make real, as a function of the price of liquidity required to clear their liabilities/obligations. Value is what sells. Insofar as EGS does not yet sell, the job of policymakers is to build markets where EGS does sell.

V. Technology and land: Intellectual property and real property

Policymakers seeking to scale up the deployment of enhanced geothermal would do well to learn how shale drillers built a liquid land lease market around their proven reserves to drive asset price appreciation. While EGS developers will not operate in precisely the same manner as the wildcat drillers that drove land speculation—the former are owner-operators, the latter were not—the comparison is instructive.

Shale fracking

The open secret at the heart of the fracking boom was that its biggest winners did not strike it rich because they used technology better than their competitors to sell more oil and gas more cheaply; rather, they understood how technological change could be monetized via land speculation. Early innovators in fracking rapidly built up inventories of land and drilling rights on low-cost sites considered unproductive by the rest of the industry and, after proving those sites' drilling potential, sold them at much higher prices to new entrants. These first-movers thus had the incentive to socialize their technologies as widely as possible, since secrecy was not the source of their value-add.

Socializing fracking technology and commoditizing land came naturally to veterans of the oil and gas industry thanks to fracking's long history as an experimental technology. Horizontal drilling experiments have been conducted as early as the 1920s, and drilling companies' combined experiences developing hydraulic fracturing techniques through the second half of the twentieth century built up a "joint stock of knowledge" in key fracking technologies.[33] For example, Mitchell Energy, the pioneer of fracking, borrowed a slickwater fracturing technique from the Union Pacific Corporation to test in the Barnett shale formation; it also hired an expert geologist of the Barnett from Chevron.[34] Moreover, numerous authors have all documented how almost three decades of public policy supported dedicated research into mapping unconventional shale gas reserves, testing hydraulic fracturing technologies, and perfecting horizontal drilling to a point where shale fracking techniques for gas, then oil, could be commercialized.[35] Finally, Mitchell Energy even patented two fluid-injection techniques in the 1980s, two decades before the fracking boom, suggesting the company appreciated the potential of the technologies it was developing.[36]

But the fracking boom was *not* an innovation story, in which Mitchell Energy used exclusive rights over its techniques to monopolize the country's production of shale gas or tried to preserve its market dominance by continually out-innovating new entrants. The truth, as summarized by

[33] Golden and Wiseman (2015).
[34] *Ibid.*
[35] Datta and Amarnath (2023); Wang and Krupnick (2013); Trembath et al. (2012).
[36] Golden and Wiseman (2015).

John Golden and Hannah Wiseman in their study of innovation policy in the fracking sector, is much more interesting: Not only did Mitchell avoid seriously enforcing its patents, but it actively encouraged technology diffusion to other drillers.[37] Through the 1990s, as it was perfecting its drilling techniques, the company bought up land across the Barnett Shale formation while strategically sharing its data with other drillers to slowly boost demand for its land—but not by so much that it would make its leases expensive overnight and thereby undercut the low prices Mitchell was purchasing them at. Only at the end of the decade did the company partner with the nonprofit, FERC-funded Gas Research Institute (GRI) to publicize its technologies and prove the value of its leases—after which Mitchell sold itself and all its land to Devon Energy in 2002, thereby justifying the commercial potential of fracking for the company's owners via the added value of its land rights rather than via shale production itself.

5.1 Why was the Devon-Mitchell merger so significant?

When Devon Energy purchased Mitchell Energy, the purchase signaled to oil and gas sector investors that Mitchell Energy's hydraulic fracturing technologies were scalable and widely commercializable. Devon wanted access to Mitchell's Texas assets as well as its extensive pipeline network. It is notable that many press releases announcing the merger highlighted Mitchell's land holdings, production quantity, and gas pipeline network rather than showcased its technology. But Devon's chairman, Larry Nichols, recognized that Mitchell's new fracking technologies could drastically improve Devon's proven reserves position on the market.

Mitchell was looking for buyers as early as 1999. Devon initially passed on a chance to purchase it; its leadership was at first unconvinced that Mitchell's fracking technology had wider commercial potential. Devon made other acquisitions across North America instead, following industry-wide expectations of a boom in demand for natural gas-powered electricity. But as Mitchell's gas production in the Barnett shale patch started ramping up in 1999, and after Mitchell drilled 120 wells in 2000 and set ambitious drilling targets for 2001—its earnings and its capital expenditure plans more than doubled in that period—Devon returned with a purchase offer.

Devon combined Mitchell's hydraulic fracturing techniques with its horizontal drilling research to create the fracking sector as we know it today, and collaborated with midstream oilfield services companies to build new "high-efficiency" drilling rigs more suitable for this new production technique and able to complete wells more quickly. A decade after the merger, Devon's chairman Nichols noted: "We thought we could take that technology and combine it with horizontal drilling and be able to significantly improve the economics of the wells and drill in a lot more places. There was some doubt in the investment community and Wall Street at the time whether or not we'd be able to do that, but obviously we have."

Sources: Natural Gas Intelligence (2002); the Journal Record (2001); Marks (2011); Sidel and Cummins (2001); Sanders (2001).

There were, of course, other reasons that encouraged Mitchell's willingness to share know-how and that guided its monetization strategy. First was public policy. As a condition of GRI's FERC

[37] Golden and Wiseman (2015).

funding and its status as a R&D collaborative for the gas industry, GRI imposed significant limits on the degree to which companies like Mitchell could enforce any patent rights on technologies it developed through GRI.

Second was the sectoral structure of the oil and gas industry that reinforced its culture of selective collaboration. Mitchell and many of its competitors would have found it too difficult to enforce patents: Fracking innovations, which can only be deployed miles underground, often in remote parts of the country, would be nearly impossible to monitor. Moreover, since any patents they had were particular to particular geographic formations, they had to constantly adapt and tweak their innovations for application elsewhere, giving them grounds to argue that they were not violating others' patents.[38] Finally, knowledge of drilling techniques flowed freely through oilfield services companies and other subcontractors, which serviced the whole industry.[39] Even if drilling companies did have confidential operating practices that helped them boost production, the profits from extraction were high enough for everyone that the potential benefits from enforcing patents against competitors just weren't worth the costs.

Not only were much of the profits made in the fracking boom made from strategic land purchases, but the value of the land above shale formations could be captured by many developers in non-rivalrous and self-reinforcing ways. Strategic data sharing among drillers improved knowledge of shale geographies and boosted lease demand across entire regions, a process which drove land lease value appreciation for all players in the market.[40] Golden and Wiseman judged that the "circulation of credible information about successful fracturing and well development could work to an early prospector's substantial favor by attracting copycats who would drive up the value of the early mover's land and mineral rights by seeking to buy their way into a winning play."[41] The widespread diffusion of information about proven reserves and fracking techniques was to some degree inevitable given that all drilling companies contracted with the same set of specialized oilfield and gas service companies to support resource extraction. "Instead of complaining that other prospectors were free riding, members of the relevant industrial community seem to have accepted the fact that such information would circulate, and designed their business models accordingly."[42] As a result of the free sharing of information, the shale patch was friendly to smaller drillers that could easily procure the services of experienced subcontractors and workers.

[38] Golden and Wiseman (2015).
[39] This was an industry where "relevant players could appropriate a satisfactory amount of value from their own technological advances but at the same time benefit generally from advances made by others." See: Golden and Wiseman (2015).
[40] Rising land values and the ease with which leases were traded supported the liquidity of the overall market.
[41] Golden and Wiseman (2015).
[42] *Ibid.*

Enhanced geothermal

Such a future is not closed off to EGS technology: If patents on geothermal drilling and heat extraction are hard to enforce or specific to particular geographies, it is plausible that first-mover geothermal developers would prefer to speculate on land with proven heat reserves rather than defend a technology licensing regime. To be sure, we cannot predict how developers will engage with this tradeoff in the medium term. But Fervo in particular is, for now, taking a middle course: The company has already acquired leases across locations specifically where conventional geothermal projects failed, allowing them to drill faster, more cheaply, and with more information than in locations where they are drilling in the dark, so to speak; one developer's trash is another one's treasure.

And insofar as EGS developers already have a readily available supply chain and workforce, it is also plausible that project-level innovations in heat extraction and electricity generation could quickly be socialized across the broader industry as the pace of project deployment speeds up. The annual Stanford University geothermal workshop invites developers to share their progress and socialize the technical details of their project pipelines.

But, even under these conditions, the pace of EGS deployment may remain significantly slower than that of shale fracking. Currently, the enhanced geothermal sector is led only by a few startup market players, each sporting distinct technologies that different investors trust. In the absence of an event comparable to the 2002 Devon-Mitchell merger, which signaled to investors the viability of Mitchell's unconventional drilling techniques, investors may not easily settle on any single EGS technology as the market standard. The consequence of this indecision is a medium-term EGS deployment landscape where these startups become the owner-operators of their specific technologies, which they might choose to defend rather than freely socialize to an ecosystem of wildcat drillers and contracted oilfield services companies. In that scenario, the enhanced geothermal sector will continue to be led by only a few market players, offering potentially lower returns to consumers.

VI. Offtake market structures: Duration, volatility, and option value

However, taking a page out of the fracking sector's land speculation playbook may not drive more debt capital toward EGS developers. Not only do fracking and EGS projects differ in relative supply and development costs, but they both are built within fundamentally different market structures that each shape the demand for their outputs, and thus affect their value propositions, in distinct ways. Although they both technically operate and sell into commodity markets, these markets—one for oil and gas resources, one for electricity—are extremely different, and those sectors themselves are positioned differently in power-sector value chains. While drillers operate in a "short-cycle" market with many intermediaries and with the ability to start and stop operations quickly, EGS developers operate like gas power plants that purchase from those intermediaries and manage equipment and contracts over a longer term.

To better understand how market structure creates a certain kind of demand profile for these assets, readers should conceptualize these underlying assets as bonds. Any fixed asset, whether a project or a bond, must be paid for upfront in cash and subsequently yields a stream of future cash flows. The two critical determinants of the value of these assets are the short-term interest rate on cash itself and the timing and structure of the asset's future cash flows. The former, the interest rate, is set in money markets (through broader monetary policy) and is shared between all bonds and assets, while the latter, the cash flow structure, is a function of the asset's ability to sell its output at a certain price in a certain period—and thus depends on the design of the market it sells into and that market's effects on demand for the asset.

Shale fracking

To start, the fracking boom was substantially the twin product of historically low interest rates and shale drillers' specific advantages in the oil and gas market. Of course, extracting subterranean resources, whether oil and gas or underground heat, requires significant upfront capital expenditure. A fall in interest rates and developers' overall cost of capital will undoubtedly lower drilling and extraction costs. All else equal, more project development is possible when capital is cheaper to access. That said, the shale boom happened very specifically during a decade of low interest rates and potentially benefited from particularly cheap corporate bond financing conditions after the 2008 financial crisis.[43] Essentially, low interest rates and low corporate bond financing costs made it incredibly easy for drilling companies to leverage their equity—based on their proven reserves—into the debt financing that massive expansions in capital expenditure required. Drillers could also borrow cheaply to lease or purchase land and speculate on the value of the proven reserves underneath.[44] A low cost of capital could not have been more important. As former Chesapeake Energy CEO Aubrey McClendon put it, "To be able

[43] Gilchrist and Zakrajsek (2013).
[44] Tong (2015).

to borrow money for 10 years and ride out boom-and-bust cycles was almost as important an insight as horizontal drilling."[45]

Energy borrowing costs remained historically low until 2015

Options-adjusted spreads measure an asset's risk relative to comparable Treasury securities

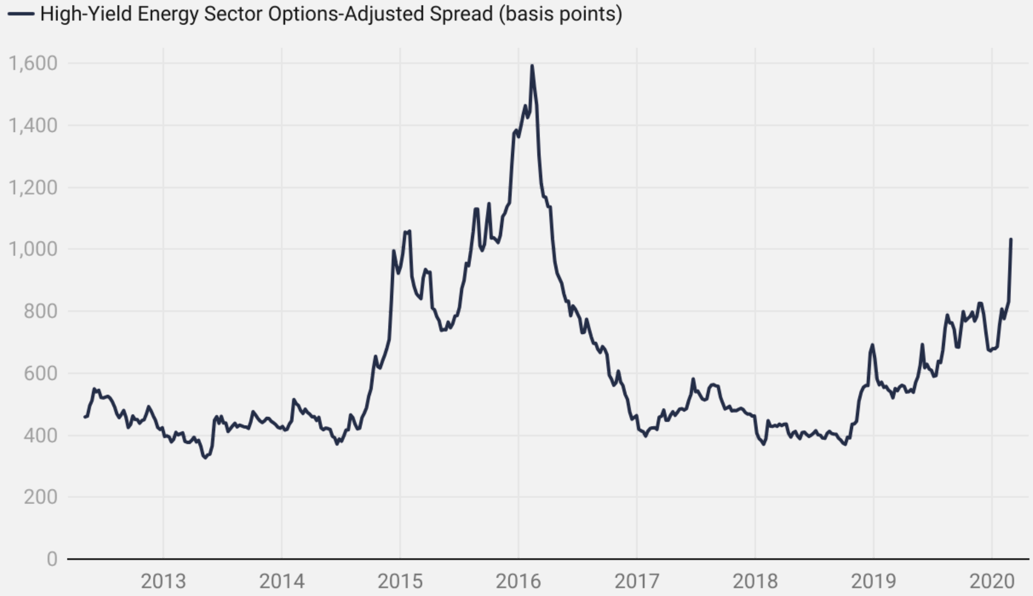


Chart: Center for Public Enterprise • Source: Bloomberg

In addition to a permissive macroeconomic environment, frackers benefited from a comparative advantage against their conventional competitors in oil- and gas-specific commodity markets. Because fracking makes upfront drilling costs so much cheaper and project completion timelines so much faster, developers and investors can get repaid from their oil and gas sales revenue in a much shorter timeframe—perhaps within a year or two—turning what was once a long-term, uncertain capital investment into a short-term project insulated from longer-term fluctuations in interest rates.[46] That compressed, "short-cycle" timeframe also allows developers to more easily hedge their anticipated revenue streams against adverse price movements because the market for those futures contracts is far more liquid over two years than, say, ten years into the future.[47] In financial market terms, frackers' unique drilling technology gave them shorter exposure to duration risk and, thanks to liquid commodity markets, they could also hedge against significant volatility risks.

[45] McLean (2018).
[46] Lack (2018).
[47] *Ibid.*

6.1 What are duration and volatility risk?

Duration is a measurement of the sensitivity of an asset to a change in interest rates. Assets with longer maturities usually exhibit greater duration; vice versa for assets with shorter maturities. While long-term fluctuations in interest rates don't seriously threaten the value of assets with shorter maturities—these assets have less duration—they can significantly change the bankability and the risk-return profile of longer-maturity assets. Infrastructure projects, including energy projects, and long-dated bonds are examples of assets with significant duration risk. Investors can hedge exposure to duration either by shifting their capital toward short-term assets or through purchasing interest rate swaps; the latter, however, grows prohibitively expensive as an asset's maturity increases.

Volatility risk is, broadly, the sensitivity of an asset's value to unexpected changes in its cash flow profile. This change in the asset's return profile can more easily be hedged against in more liquid markets where many investors and speculators trade that kind of asset. Investors in infrastructure projects usually seek to minimize volatility risk through investments in projects that have steady cash flow profiles or creditworthy offtake commitments and, if not, seek guarantees to hedge their exposure to cash flow volatility. Investors in commodities, however, usually embrace potential price volatility and speculate on it in order to secure higher returns.

And because frackers can turn their wells on and off faster and more cheaply than conventional drillers can, they have what's functionally an options contract which they can exercise against rapid changes in the price of their output.[48] In other words, they could simply choose not to operate as many wells. In an environment of uncertain prices or uncertain future market demand, shale drilling's low relative capital costs and striking operational flexibility with respect to market demand make it an extremely attractive proposition to investors seeking higher returns rather than stable, long-term cash flow. While the reality of the shale boom did not play out in precisely this manner, as the next section will detail, investors were convinced by this line of reasoning.

OPEC, the Organization of Petroleum Exporting Countries, an international oil supply cartel (at least in name), discovered the "option value" of shale the hard way when it tried to increase oil supply and drive down prices to force American frackers out of business. Falling prices prompted the drillers that did not go bankrupt to drill only in the most promising locations rather than in marginal fields, invest in decreasing drilling times for new wells, and improve well productivity.[49] Oilfield services companies reduced their margins, as well, in light of fewer customers. The combination of these factors led to break-even oil prices falling for the drillers that did stay in business—and, when prices went back up, those drillers could drill new wells in a matter of weeks. Fracking drillers demonstrated their ability to become the marginal price-setters in oil markets, sucking volatility out of the market and thereby displacing OPEC's historic price-setting power.[50]

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[48] Avinash Dixit and Joseph Pindyck flesh out a mathematical economics framework for understanding capital investment as an options contract in their book *Investment Under Uncertainty*.

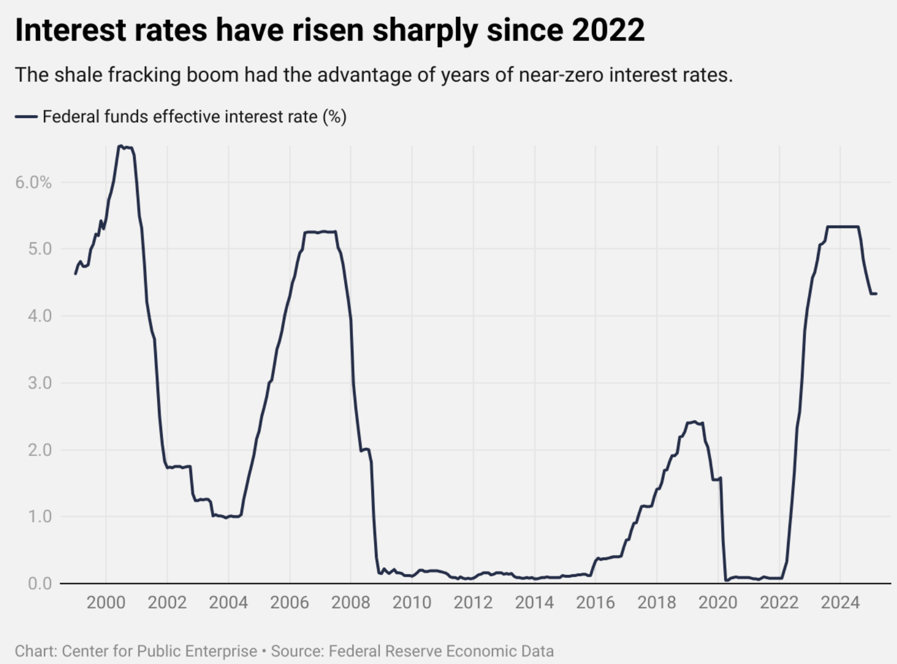
[49] Vara (2017).

[50] Vara (2017), Parameshwaran (2022), and World Bank (2018).

Stepping back to provide more context, it's important to remember that commodities, as an asset class, are generally easy to store and can be traded like-for-like across time between present and future production[51]—and that oil and gas markets are truly global commodity markets. They have complex networks of speculators and infrastructure providers (*e.g.*, shipping, pipeline, and refinery companies) that allow current production to be stored and used as needed to meet present and future demand at a price that is set globally. Fracking drillers sit on the far upstream end of this market, competing with other oil and gas producers to sell those resources to intermediaries which, in turn, sell them to final consumers. The cash returns to drilling are volatile, insofar as they are determined by rapidly changing spot prices in these global markets. But, by virtue of their upstream position and their technology, both fracking drillers and their incumbent competitors alike can ride waves of commodity price volatility by shifting the intensity of their production capacity—although fracking drillers can react to changes in market conditions much faster.

Enhanced geothermal

The market structure of the enhanced geothermal sector is nearly the opposite. Most obviously, EGS projects are being developed today at *much* higher costs of capital—an effect not just of structurally higher interest rates but also of private creditors' skittishness around investing in a technology with a checkered risk profile. No doubt lower interest rates and better debt markets for geothermal projects will help speed along deployment and increase the bankability of all EGS projects.



[51] In other words, they have what economists call an "own rate of interest."

Even with lower interest rates, however, EGS projects are not "short-cycle" investments. Not only do EGS developers have to build drilling rigs and extract heat, but they have to build a power station and acquire all the constituent components—turbines, transformers, safety equipment, and a grid interconnection permit. This process currently takes five years, if not more. Especially given delays in transformer procurement timelines, the sheer length of the grid interconnection process, and other non-financial investment barriers facing power station development more broadly, it does not matter much if EGS firms can drill flow test wells and extract heat within a year or two like frackers could with oil and gas.

Additionally, EGS projects are not operating in the same kind of deep, efficient commodity market that barrels of oil and tanks of gas do; EGS projects sell their outputs into electricity markets, which are constrained by transmission bottlenecks, grid balancing requirements, and limited grid-scale long-term electricity storage capacity. These bottlenecks, long project construction times, and the increasing importance of variable and peaker resources (*e.g.*, solar, wind, peaker gas) on the grid all work to prevent developers of clean firm energy resources, including but not limited to EGS developers, from hedging easily against spot price volatility. Developers cannot easily predict electricity market conditions upon project completion when expected project completion dates are years away, limiting their willingness and ability to sell their electricity into spot markets directly or through futures contracts.

This is why most developers of clean energy, including enhanced geothermal power, seek out long-term power purchase agreements (PPA) with customers willing to buy a significant portion of their plants' lifetime power generation output upfront at a fixed price.[52] Although PPAs help clean energy developers sidestep day-to-day spot price volatility, developers' high upfront costs and dependence on large volumes of upfront debt finance render clean energy projects, EGS projects included, a significant duration risk to investors—in this case, the risk that the PPA price they negotiated at the start of the project will no longer return well against the interest rate on money that exists at the end of the project's or PPA contract's life.

It does not help that only a few large purchasers, mostly tech companies and manufacturing firms, can commit to long-term PPAs (greater than ten years); they are some of the only private market actors that can predict their electricity demand so far out and purchase accordingly. This slice of the power market is therefore monopsonistic, characterized by a small pool of buyers with significant purchasing power; absent any expansion in this buyers' market, upfront PPAs may seriously disadvantage clean firm energy developers, even if they insulate them from price volatility.[53]

EGS projects would benefit significantly from policy action that expands the offtake market. The market size of a power project is really only as large as the size of the electricity grid in which it is located, as opposed to the global market that oil and gas have. A rapid buildout of batteries and long-distance transmission to the grid—which would both allow for greater electricity market liquidity insofar as the former helps balance prices through time and the latter helps balance

[52] Feygin and Lala (2024).
[53] Kasliwal et al. (2024).

prices across space—could therefore help break clean energy developers' dependence on suboptimal PPA arrangements.

Even with this kind of policy support for electricity market commodification, however, EGS projects will never have the "option" quality of shale fracking drillers. The low cost of fracking and the ease of turning wells on and off made American drillers the global marginal price-setters for oil and gas production—but, absent greater utility or grid incentives for clean firm energy generation, EGS projects bidding into "deregulated" wholesale electricity markets as "merchant" generators (rather than being compensated through a PPA) will have return profiles subject to the volatility of spot electricity prices that they cannot control. Those spot prices will instead be set by variable renewable energy, batteries, and peaker gas plants, which will always take priority in the "merit order" of wholesale electricity markets due to their ability to produce electricity at the lowest marginal cost. In other words, enhanced geothermal projects cannot suck price volatility out of the market as well as their competitors can. Additionally, there is no scenario where EGS power is the only block of flexible, dispatchable power available to be the marginal price-setter on a deregulated electricity grid.[54] Grid operators already have other baseload power options. For these reasons, first-of-a-kind EGS projects may be especially difficult to market to utilities inexperienced in balancing geothermal power generation.

Finally, while EGS developers can of course exercise their option to produce electricity by turning their wells and power stations on and off, they are not likely to drill wells without using them. EGS is a nascent sector and there are no comprehensively derisked heat reservoirs across the country. (In contrast, fracking firms already knew where they could likely access shale oil and gas, thanks to decades of public-private mapping of the country's underground fossil fuel reserves.) It currently costs too much for an EGS developer to drill a flow test well to measure power generation capacity *without* also building the corresponding power station with which to recoup those flow test drilling costs. For these reasons, EGS projects are truly power generation infrastructure projects: sources of longer-term, stable cash flows rather than speculative commodity extraction plays.[55]

All of which is to say that the oil and gas sector is an entirely different line of business from the enhanced geothermal energy sector. The resources extracted—heat intended to be converted into electricity, on the one hand, and shale oil and gas, on the other—are distinct from the perspective of a project financier weighing their respective risk and return profiles. It is harder for EGS developers both to quickly monetize the untapped value of their resources and to sustainably hedge volatility and duration risks. The fundamental difference in market structures here suggests that scaling up EGS requires new kinds of policy support, to stabilize and expand consumer demand for clean geothermal electricity; to subsidize heat resource confirmation, drilling flow test wells, and conducting flow tests; and to lower the cost of capital and surmount

[54] Of course, enhanced geothermal is a "firm," dispatchable energy source, which allows it to take advantage of power market mechanisms such as capacity markets and ancillary services. Whether an EGS developer can make use of these mechanisms depends on the design of the RTO/ISO it's in—and whether the grid operators and its constituent utilities demonstrate a preference for clean firm power over dispatchable gas.
[55] Arun (2024b).

investment barriers to building geothermal power stations. The next section details how the oil and gas sector had access to some of this support—and how enhanced geothermal does not.

VII. Legal and financial quirks: Tax law, accounting practices, and deal structures

The shale boom was a windfall for investment bankers, contract lawyers, and land speculators, all of whose decisionmaking and control over specific bottlenecks in the project financing process made the shale boom so massive—and, consequently, made the bust so catastrophic. The legal and financial minutiae of the shale boom are perhaps the most fascinating aspects of this comparative analysis.

Shale fracking

Policy support for lowering the capital costs of drilling only reinforced shale fracking's status as a high-return "short-cycle" investment. Oil and gas drilling companies had access to tax deductions for "intangible drilling costs," which, as Employ America has written, "drastically reduced the cost of experimentation with new drilling techniques by allowing companies to deduct 60–80% of drilling expenditures rather than capitalizing them over multiple years."[56] The deduction facilitated the ability of independent shale oil and gas producers—the "wildcat" drillers—to rapidly reinvest their revenues into further production, particularly because they "could deduct the entirety of their [intangible drilling costs] in the year incurred." Independent drillers that did not have refining or retail operations could also access a "depletion" allowance that exempted 15 percent of their gross revenues from taxes. The shale boom undoubtedly benefited from the ease with which drilling companies, particularly wildcat drillers, could recycle their capital.[57]

It helped that sell-side analysts and accounting firms valued these companies' prospects using accounting frameworks that, in hindsight, look suspect. David Einhorn of Greenlight Capital, a buy-side investment firm, judged in 2015 that the value of oil fracking company Pioneer was vastly overstated.[58] Sell-side analysts' use of a "multiples"-based valuation method, whereby a company is valued at some multiple of its EBITDA (earnings before interest, tax, depreciation, and amortization) that reflects how much investors are willing to pay for it, was strictly inferior to a more sober analysis of the company's long-term discounted cash flow—to say nothing of Pioneer's suspicious assumptions about the rates of return on their wells; even giving Pioneer the benefit of the doubt on their price assumptions and cost of capital, Greenlight's discounted cash flow model argues that Pioneer's revenues never covered its long-term cost of capital. As Einhorn put it, "The company's equity has nothing more than option value. Some have suggested that Pioneer could generate more value by drilling faster. Actually, that would make it worse, as faster drilling brings forward the value destruction."[59]

[56] Datta and George (2025).
[57] Golden and Wiseman (2015).
[58] Lopez and Crowe (2015).
[59] *Ibid.*

These inflated valuations were a boon for drillers and their investment bankers, which started inking "cash-and-carry" contracts, which were essentially co-investment and profit-sharing agreements, between drillers and co-investors.[60] Two journalists described one famous 2008 deal between two gas drilling giants as such:

> *"Plains would pay Chesapeake $1.7 billion to gain ownership of about one-third of the drilling rights that Chesapeake had leased in the Haynesville. Plains would also commit to paying out another $1.7 billion to cover half of Chesapeake's drilling costs, in return for part of the future profits."*[61]

Chesapeake and its investment banker, Jeffries, booked massive profits on this transaction: "Chesapeake spent an average of $7,100 an acre on the drilling sites it had leased in the Haynesville. Plains paid Chesapeake the equivalent of $30,000 an acre. Jefferies and the other firms involved in arranging the deal made an estimated $23 million on this transaction."[62] Cash-and-carry contracts became a popular way for drillers to finance gas extraction at a profit, particularly as lease values remained inflated during a period of high gas demand.

But such high gas demand produced a glut of shale gas; as gas prices fell, so did lease valuations, prompting property owners to protect their interests via contract law. While the previous section explained how shale wells, in theory, approximate an "options contract"—in a situation of falling prices, drillers should be able to turn off their equipment and wait for prices to rebound—the reality was far different: pressure from landowners and some investors alike ended up *requiring* drilling companies to continue extracting shale gas even when market conditions soured. Some co-investors in cash-and-carry deals seem to have imposed quantity targets for how much gas they wanted produced.[63] Meanwhile, landowners, who earn upfront lease payments and continuing royalty payments from the production and sale of all oil and gas extracted from their land, often added "use it or lose it" clauses to their leases.[64] These clauses require drilling companies to drill and sell what they extract within a set amount of years in order to keep their lease.[65] The threat of losing a lease is substantial, not just because the drilling companies might have already paid tens of thousands of dollars per acre—upfront and at inflated prices, of course—to access that land, but because losing a lease might prevent a drilling company from legally conducting horizontal drilling across pooled lease parcels.[66] When drillers went bankrupt from being forced to drill below breakeven prices, they were quickly replaced by drillers who were willing to take lower profit margins. Fracking's short-cycle nature and the ability of newer, lower-margin wildcat drillers to quickly re-tap pre-drilled wells with their predecessors' equipment allowed production to continue, exacerbating the glut even when falling prices would force other drillers with similar costs to shut down.

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[60] There are options-market transactions also called "cash-and-carry" contracts. These options transactions are generally distinct from the "cash-and-carry" agreements being described here.
[61] Krauss and Lipton (2012).
[62] *Ibid.*
[63] Krauss and Lipton (2012).
[64] Gibson (2012).
[65] Harvard Law School Emmett Environmental Law & Policy Clinic (2014).
[66] Most drillers used "pooled lease" arrangements. See: Gibson (2012).

That's not to say that nobody expected or predicted a glut from fracking or the subsequent collapse in the sector's value thanks to waves of bankruptcies—but, clearly, too few market participants seemed to be aware of this possibility. Much of the "smart money" was, in a word, speculating off the hype that the shale boom generated. And many drilling companies had no choice but to engage in their own value destruction.

Enhanced geothermal

Enhanced geothermal projects don't appear to have most of these qualities. Because individual EGS projects are power infrastructure projects with longer-term offtake contracts, financial analysts will generally evaluate them using discounted cash-flow modeling appropriate for infrastructure projects rather than with "multiples" valuation models that presuppose future asset value growth—especially insofar as the lack of comprehensive underground heat resource confirmation at the level of individual land parcels prevents market participants from speculating on the value of leases and their proven underground heat reserves.

It's also not clear that EGS developers or potential creditors are yet willing to use "cash-and-carry" contracts.[67] While it is possible that investors could support EGS capital expenditure in return for a slice of PPA revenues, or that offtakers could support that capital expenditure in return for a PPA discount, this kind of pre-pay structure does not exist at scale. And while some states require drilling leases to include "use it or lose it" clauses, the previous section details why EGS developers already cannot treat their wells as "options." Once a well is drilled to access underground heat, EGS developers cannot yet refuse to use it.

Additionally, while the "intangible drilling costs" tax deduction technically applies to geothermal drilling, too, Employ America details precisely why EGS project developers cannot take advantage of it as it is currently designed to lower their upfront costs: "next-generation geothermal projects … face protracted drilling timelines, siloed LLC structures, and multi-year revenue delays."[68] As mentioned previously, geothermal projects that take multiple years to reach completion cannot deduct drilling costs from a tax burden they do not yet have, to say nothing of the fact that EGS developers may legally and financially partition their no-revenue drilling operations from their revenue-generating power station operations.[69]

Scaling up EGS power deployment certainly requires lowering developers' costs of capital, thus improving discounted cash flow analyses of individual projects. But tax policy does not offer EGS projects a functional tax deduction structure. Nor are there market participants interested in underwriting creative investment structures through which developers and investors share both capital expenditure costs and profits—the industry is too nascent, its profitability yet unproven.[70]

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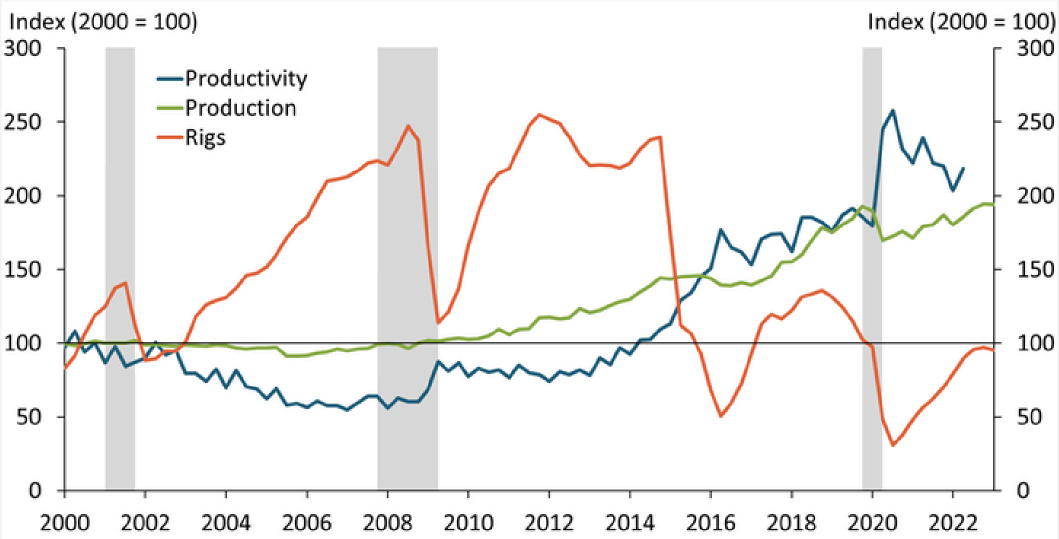
[67] Technically speaking, construction and term loans already provide creditors with the right to a project's cash flows; the right to a share of the project's residual profits requires an equity investment.
[68] Datta and George (2025).
[69] *Ibid.*
[70] Arun (2024a).

VIII. Policy recommendations

The end of the fracking boom—the "bust"—bankrupted wildcat drillers and forced incredible consolidation of production across the sector. The heyday of fracking is long past; these days, the industry commits to capital discipline, reducing rig count and labor force while maximizing productivity through technology.[71] But the boom that led to the bust still upended global commodity markets, made the United States an energy producing superpower, and built out hundreds of billions of dollars worth of drilling and pipeline infrastructure at minimal returns. This degree of spending is, from a policy perspective, what clean energy deployment requires—*even if* it seems reckless in hindsight.



EGS deployment, however, will not proceed the way fracking did. Juxtaposing the financial and legal infrastructures underpinning the fracking boom against the current state of the EGS sector suggests that the two are more different than they are similar. The compelling narrative that enhanced geothermal's technology and workforce requirements parallel those for fracking butts up against the reality that the fracking boom was a commodity speculation business, whereas geothermal power is, simply put, an infrastructure business that just happens to integrate fracking technologies into power station development.

Contrasting these two sectors helps shed light on the market structures and policy supports that can drive the rapid deployment of enhanced geothermal power in the short- and medium-term. It's clear from this analysis that successful EGS deployment requires the following policy supports:

[71] Brown et al. (2023); Lindquist (2024); Carr et al. (2024).

8.1	Policy recommendations
1	Derisk the exploration of heat resources.
2	Project finance and offtake support.
3	Build greater long-distance electricity transmission capacity.
4	Support technology diffusion.

1. **Derisk the exploration of heat resources.** The market for land leases will not grow more liquid without more precise plotting of underground heat formations; nor will EGS developers be able to credibly claim proven reserves *until* they can successfully extract heat at a predictable rate. Public-private research collaborations to conduct heat flow tests will make claims of proven reserves credible to potential investors. Policymakers should replicate the Department of Energy's FORGE test site for enhanced geothermal drilling across the Mountain West region, if not elsewhere across the country, to derisk the discovery of basins of commercializable heat reserves both for developers and investors.[72]

   Still, individual wells can fail to tap heat consistently even where the geology of a "derisked basin" seems favorable. Unless EGS developers can write off the costs of drilling temperature test wells across the country in order to drill enough wells in different locations such that a few successful pilot power stations could cross-subsidize the money lost on unsuccessful capital expenditures elsewhere, EGS developers have little economic incentive to drill flow test wells without also building a corresponding power station with which to recoup their flow test drilling costs. Indeed, unlike fracking, and until EGS project pipelines become large enough to drive project standardization, each enhanced geothermal project is bespoke, with its own idiosyncratic drilling risks.[73] To that end, policymakers should better **derisk flow test drilling** itself. Some policy options include, a **transferable tax credit** for exploratory drilling (with a direct pay / elective pay equivalent), **depletion allowances**, and **pre-payment financing** (a version of a cash-and-carry deal structure, as detailed below in the next set of recommendations).[74]

   Another model for derisking exploration is a **combined loan and insurance product**. Germany's national development bank, KfW, is partnering with reinsurance firm MunichRE to offer this kind of joint product: KfW's loan is "conditionally repayable and provides for debt relief of up to 100 percent of the bank loan for the drilling if no or only partial discovery is made," and the insurance mechanism, which focuses on heat supply for municipalities and industries, "corresponds to the drilling costs and also includes a

[72] Ough (2025).
[73] Barnard (2025).
[74] Policymakers should not ignore the benefits of providing catalytic financing to other firms in the enhanced geothermal supply chain, particularly upstream technology firms providing resource mapping services.

dynamic adjustment to possible rising costs and stimulation measures, such as drilling a sidetrack or acidifying an initially dry well. The possible payout is defined based on the thermal output achieved."[75] Partial exploration leads to a partial payout. Other countries also have different geothermal exploration incentives.[76] As a generalizable model for derisking flow test drilling, public financing instrumentalities could offer **pre-development loans that are forgivable as grants** if exploration fails to tap heat and/or that convert into construction or permanent debt products if flow test drilling succeeds.

2. **Project finance and offtake support.** In theory, higher PPA prices will make geothermal projects more bankable to longer-term debt investors. But, in practice, the sector is not at a point where demand signals alone can call forth additional energy supply. Where demand for clean firm energy *does* exist—from tech companies and manufacturing firms in particular—lenders remain unsure about the output and cost of EGS projects.

   Most investor appetite for enhanced geothermal projects comes from equity and venture capital investors, which are betting on various EGS firms' abilities to create "derisked basins" of accessible and consistent heat resources in a manner that gives them an edge over their competitors and raises their corporate valuations in the process. Institutional investors in project debt, on the other hand, care about an EGS firm's specific competitive advantages only insofar as they can produce long-term returns from each specific project that is being financed within the"derisked basin," with minimal costs and operational risks. Even existing public sources of project finance like the Department of Energy's Loan Programs Office will need to see some proof of the longevity of an EGS project's cash flow profile before it can provide its concessional capital. In addition, the timeline and delays to completing the power station half of an EGS project will undoubtedly spook lenders further. To be sure, Fervo's announcement that its projects have stable heat rate measurements should begin to shift investors' perceptions; its recent construction loan from X-Caliber Rural Capital is proof that at least some debt investors trust that Fervo's project pipeline is bankable. But without more projects in new locations achieving stable heat extraction rates and without project development itself speeding up, lenders will not supply finance at large enough volumes or on good enough terms to ensure that EGS developers are bankable even at higher PPA prices.

   Public policy can address these problems in a targeted manner.[77] First, public financial entities can provide **short-duration term loans** that derisk an EGS project's first three to five years of cash flows, providing an EGS project with enough cash flow history to refinance that term loan into a longer-duration term loan with private lenders, including institutional investors, or potentially federal lending programs such as REAP, the Rural

[75] Cariaga (2024).
[76] IEA (2024).
[77] CPE has previously explored many of these potential solutions in greater detail, and for other technologies. All of these recommendations draw from our extensive research on the key barriers to mobilizing investment into infrastructure project finance. See: Arun (2024b); Arun (2024c); Arun (2025a); Arun (2025b).

Energy for American Program, and the Title 17 authority at the Loans Program Office.[78] Public financial entities can also offer a "**pre-payment**" analogue to a cash-and-carry contract: They can pre-pay some of an EGS developer's exploration, drilling, and construction costs in return for a proportional discount on the PPA price, providing liquidity for developers and the other entities eventually entering PPAs with them for power from the same project. These pre-payment funds could be supported by state bonding capacity or other public lending authorities. This prepayment agreement would both derisk EGS projects during their higher-risk construction phase and help compress project development timelines by providing ready construction finance support and a creditworthy offtake commitment to the EGS developer.[79]

Where PPAs may not be forthcoming, however, states and utilities can set up **offtake warehousing facilities** that sign a PPA with an EGS developer upfront at a pre-arranged strike price and resell tranches of that PPA to third-party customers as the EGS project nears completion and market actors can more readily predict their power demand needs and purchase power contracts accordingly.[80] This warehousing facility, by providing a creditworthy PPA upfront, makes projects bankable instantly while turning the state or a utility into a market-making "dealer" in offtake contracts. (CPE will publish further on this proposal.)

3. **Build greater long-distance electricity transmission capacity**.[81] The fragmentation of the United States' energy grid artificially reduces the offtake possibilities for any geothermal project. Absent the kind of warehouse solution in the previous suggestion, EGS developers will likely remain dependent on a long-term corporate PPA from a tech company or manufacturer already located on the same grid as the potential EGS project. These PPAs, offered by a monopsony of corporate purchasers, could potentially disadvantage EGS developers.[82] The Rhodium Group has suggested[83] that "behind-the-meter" geothermal could, through co-location, *physically* match geothermal power supply to sources of stable demand,[84] but this recommendation,

[78] Most private institutional investors interested in longer-term infrastructure debt investments seek three to five years of proven cash flows before they are likely to treat a project as safe. See: Arun (2024b).
[79] Amazon's equity investment into X-Energy, a small modular reactor developer, is similar but not identical to this approach. This equity investment dilutes X-Energy's corporate equity, whereas a pre-payment agreement supports project finance without diluting a developer's equity and a cash-and-carry agreement as conventionally designed would involve an investment into project equity rather than dilute sponsor equity. See: Allsup (2025).
[80] This warehousing facility would resemble the Department of Energy's Transmission Facilitation Program in design. CPE will write more about the specific design of such an offtake structure in a future publication. See: "Transmission Facilitation Program," U.S. Department of Energy.
[81] Insofar as policymakers and community leaders might worry about the seismicity risks of EGS projects—although these risks are low—policy support for a buildout of transmission capacity across the U.S. electric grid allows developers to site EGS projects away from population centers while still providing communities dense and rural alike with the benefits of new clean firm energy resources. Transmission thus helps provide social license to EGS projects. Publicly available, credible subsurface data mapping to track seismicity would also support policymakers' efforts to provide EGS developers with a social license to operate.
[82] Kasliwal et al. (2024).
[83] King et al. (2025).
[84] *Ibid*.

which deepens EGS developers' dependence on a monopsonistic buyers' market without otherwise providing other sources of liquidity to developers, seems strictly inferior to expanding the pool of potential buyers of the resource.[85] **Expanding the ability of FERC and the Department of Energy to support greater transmission buildout and grid integration**—not to mention addressing a bottleneck in transformers—helps not just EGS project developers but developers of all clean energy resources.

4. **Support technology diffusion.** There are ample technological reasons why EGS projects could still fail outside their pilot locations, including but certainly not limited to the limited durability of drill bits, casing materials, and well monitoring technology in high temperatures and pressures.[86] Geothermal power developers could build upon the Department of Energy's FORGE test site for enhanced geothermal drilling to organize a nonprofit research consortium in the model of the Gas Research Institute (GRI), the federally supported, nonprofit research institution supporting the development of innovative gas extraction technologies.[87] Crucially, in return for public funding for GRI—in the form of a FERC-imposed surcharge on interstate gas pipeline flows—GRI's constituent members, which included drilling companies, distributors, and pipeline operators, agreed to waive intellectual property claims on GRI's research outputs.[88] A **geothermal power research collaboration** between developers, FORGE, the national laboratories, and state governments could work similarly, perhaps supported by a surcharge on investment into EGS projects or production of clean firm electricity from those projects.[89] Drilling technology and know-how, as well as heat confirmation techniques, could also spread through more passive means, such as through oilfield service companies and through workers contracted to support various distinct projects. No matter what, project developers seeking to preserve trade secrets can, following Mitchell Energy's model, avoid collaborating with any research consortium on anything too sensitive to be publicized.

These suggestions will certainly take some time to implement. But, in the medium-term, they will drive faster growth in the enhanced geothermal sector by providing "exit liquidity" to the various enhanced geothermal startups seeking to become owner-operators of long-term EGS projects across various "derisked basin" geographies. Policy support for heat resource discovery and for derisking flow test well drilling will socialize among developers and investors the risk profiles of various geothermal technologies across various basins, thereby attenuating the uncertainty investors may feel about providing longer-term debt finance to individual project

[85] In a medium-term future where, despite high demand for clean firm energy resources, developers still face grid interconnection challenges, it is plausible that behind-the-meter enhanced geothermal could grow more popular as a strategy for matching supply and demand. Even then, such a strategy relies on derisking both new EGS projects and on stabilizing manufacturing supply chains.
[86] Barnard (2025).
[87] "FORGE," U.S. Department of Energy.
[88] Golden and Wiseman (2015).
[89] This proposed research collaboration should be technology-agnostic, insofar as "enhanced geothermal" is only one of several viable "next-generation" geothermal project types. For example, startups such as XGS and Eavor, considered "advanced geothermal" rather than "enhanced geothermal," have different drilling technologies than Fervo and Sage do. Even Fervo and Sage use different heat extraction techniques.

finance structures. The confluence of growing energy demand and less risk-averse debt capital will drive a more liquid market for land leases and drilling rights among geothermal startups angling to become owner-operators across a portfolio of projects. Policy that encourages transmission capacity growth and builds more liquid electricity offtake market structures will ensure geothermal developers can access financially sustainable PPAs. The combination of these two trends will ensure that greater energy demand will drive growth in the supply of EGS installations. While EGS projects' electricity generation profiles still disadvantage them relative to solar, batteries, and peaker gas plants, all of which are marginal price-setters in wholesale electricity markets, policymakers can set up incentives for utilities to procure clean firm energy sources such as geothermal for their baseload power needs.

To be sure, even if policymakers derisk heat resource discovery and flow test drilling, EGS projects will still take two to five years to build simply on account of their power station components: Due to global shortages, transformers and potentially turbines might need to be procured and even stockpiled well before projects begin their construction phases, to say nothing of the delays all energy developers face when adding their projects to their electricity grid's interconnection queue. All of which means that the precise manner by which EGS developers proceed through the project development process—do they need to buy turbines before or after they find a sustainable underground heat reserve? Do they sign a PPA before or after they procure turbines and transformers?—has significant implications for their liquidity at different stages of the project development process. To the best of our knowledge, there have not been enough EGS projects developed for investors to force a standardized project development procedure (for the orderly purchasing and procurement of input components and legal permissions) onto individual developers.

IX. Conclusion

Recent policy proposals outlining the potential of enhanced geothermal power do not comprehensively explore these solutions.[90] At most, existing policy-racing resources emphasize the need to more comprehensively confirm heat resources across the country and to derisk land access and flow test drilling. All of them frame enhanced geothermal as the successor to fracking, and some gesture toward how it requires lower costs or better financing, but none dive into the particular project finance obstacles standing in the way of its commercialization. As such, our report and recommendations should be a useful resource for policymakers looking to evaluate the growing interest in enhanced geothermal power and to gauge what policy supports this new technology requires.

Indeed, enhanced geothermal is still evolving as a technology. Sage Geosystems can use its geothermal system to store excess energy like a battery, and Fervo is working on a similar storage pilot.[91] Storage resources fit into broader energy markets in a manner distinct from generation resources. While this report does not consider EGS power's unique potential in this respect, the market structure for enhanced geothermal storage systems looks to be a productive topic for further analysis.

Additionally, EGS projects still depend on conventional power station inputs—primarily turbines and transformers. It's plausible that a looming gas turbine shortage will advantage the economics of EGS projects, which rely on organic rankine cycle turbines to turn heat into electricity. But, globally, there are only a few manufacturers of those turbines, and those manufacturers only build to order, suggesting that any rapid scale-up in EGS project deployment might *not* translate to a rapid expansion in production of EGS-specific turbines. A similar situation prevails in transformers; procurement is slow and delays plague the industry.[92] Since project developers have to procure turbines and transformers sometimes years in advance of even constructing a project—and insofar as power station construction itself already takes years of planning and permitting—project developers face significant liquidity risks.[93] A concentrated, oligopolistic input market would throttle the speed of EGS project development and almost certainly prevent new independent players from emerging.

In defense of the policymakers and analysts comparing geothermal to fracking, there is truth to the narrative that geothermal power allows workers in the oil and gas industry to transfer their skills. That workforce's transition into the geothermal industry could defuse potential opposition to the nascent technology and could help communities, too. Of course, it is not clear whether this potential employment transition story will carry political salience when American ratepayers, as consumers of electricity, are more focused on energy affordability than on the particular

[90] Morgan Stanley (2024) and King et al. (2025).
[91] Roberts (2025) and Sage Geosystems (2023).
[92] Rathi et al. (2025) and Trabish (2025).
[93] Arun (2025b) and Martin (2025).

resource mix used to generate it. But, either way, this transition will never happen without more rapid project deployment and derisking.

All of which is to say that the growing enthusiasm for geothermal energy is belied by the reality that there are only a handful of working pilot and demonstration projects across the country. States, utilities, and the federal government alike have, as yet, refused to commit the resources necessary to commercialize this unconventional energy source. The sector's status quo market structure not only imposes structural bottlenecks on the speed of EGS project deployment but threaten to keep the sector highly concentrated, with fewer social returns than policymakers are hoping for.

If policymakers believe in the potential of enhanced geothermal technology, then they should immediately support the research, offtake, and project financing needs of EGS developers. Geothermal, like natural gas before it, could quite literally become the next bedrock of the American energy system—but only if policymakers embrace the power of both contingent market conditions and policy-specific financial tools to catalyze investment into the deployment of clean firm energy resources at scale.

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Marcellus Shale Gas Drilling Tower in Lycoming County, PA by Ruhr Fisch/Flickr.

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