I. What is enhanced geothermal, and how does it differ from conventional geothermal?

Conventional geothermal power generation, also known as "hydrothermal," requires a geological trifecta: sufficient subsurface heat, a permeable reservoir, and naturally-circulating fluid. When developed, it is generally considered cost-competitive with other firm resources, with an LCOE between $60 and 110/MWh depending on resource quality and plant type.[1] However, these conditions can be challenging to find and develop, partially explaining why the nation's installed geothermal capacity (~3.9 gigawatts) represents only about 10% of the economic potential of the resource (~40 gigawatts).[2] It is worth noting that, after decades of stagnation, AI-enabled resource prospecting has reinvigorated this industry; in 2025, three new hydrothermal fields were discovered using AI.[3]

EGS eliminates the need for natural permeability and fluid by engineering the reservoir.[4] The process borrows directly from advancements made during the unconventional oil and gas boom: developers drill horizontal wells at depths of 5,000–15,000 feet (1.5–4.6 kilometers), hydraulically fracture the rock to create permeability, and circulate water through the fractured zone to extract heat. The heated water returns to the surface and drives a power plant.[5] The system has near-zero emissions and low water consumption.[6] Because EGS requires only hot rock—which exists everywhere at sufficient depth—the technology can theoretically be deployed across the entire western U.S., not just at the handful of hydrothermal "sweet spots" that support conventional plants.

The critical enabler allowing EGS to commercialize so quickly is technology transfer from the shale revolution. The same directional drilling rigs, completion techniques, fiber optic monitoring systems, and skilled workforce that unlocked unconventional oil and gas are now being applied to geothermal reservoirs. At Fervo Energy's Cape Station project in Utah—the world's first commercial-scale EGS facility—more than 90 percent of on-site labor hours come from oil and

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[1] National Lab of the Rockies (NLR). 2025. 2025 U.S. Geothermal Market Report.
[2] U.S. Department of Energy. 2019. "GeoVision: Harnessing the Heat Beneath Our Feet." This report estimates approximately 40 GW of economic conventional geothermal potential against 4 GW of installed capacity.
[3] Zanskar Geothermal & Minerals. 2025. "Zanskar proves first blind geothermal discovery using AI."
[4] This report focuses on EGS due to more readily available recent data and examples of commercial projects. Other next-generation geothermal systems may also provide these benefits and accelerated timelines, however less information is available as of this report writing on deployment timelines for other types of next-generation geothermal systems in the U.S.
[5] Typically a binary Organic Rankine Cycle (ORC) power plant, but this is an active area of innovation.
[6] U.S. Department of Energy, Geothermal Technologies Office. "How an enhanced geothermal system works."

gas workers.[7] Those workers are employing the same processes that are used to drill the 10,000+ unconventional wells produced annually in the U.S. The industry is scaling with much more industrial expertise than would be suggested from a single commercial plant, providing confidence in a rapid, repeatable development process.

II. The 3–6 year development timeline

Recent project development data show that a next-generation EGS project can move from active development to commercial operation in 36—52 months under favorable conditions, with a conservative IRP planning range of three to six years from project initiation. This represents a 70–75 percent reduction from the seven-to-ten-year timeline frequently cited for conventional geothermal development on federal land.[8]

Phase-by-phase breakdown

Because a majority of geothermal power development occurs on federal public lands, federal leasing and permitting processes highly impact project development timelines. Recent analysis estimated 975 GW of technical EGS potential and 130 GW of hydrothermal potential on federal lands, suggesting significant opportunities to expand geothermal energy.[9] It is worth noting that the phases outlined below apply most readily to developers which have already secured a geothermal lease position or similar land holding.

Federal leases confer the right to future exploration and development but do not authorize ground-disturbing activity on their own. Each subsequent phase—exploration, resource drilling, production, and reclamation—requires separate authorization under the Geothermal Steam Act and its implementing regulations. Developers that must first acquire lease positions through the BLM's competitive auction process likely add at least 12 months to their timeline before Phase 1 can commence.

Phase 1: exploration and site characterization (months 1–6). Modern EGS reduces exploration risk substantially compared to conventional geothermal. Because the technology does not depend on discovering a unique hydrothermal reservoir—hot rock is readily accessible at depth across the Mountain West—exploration focuses on confirming temperature gradients, stress regimes, and rock properties rather than locating a hidden resource. Prefeasibility analysis,

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[7] Fervo Energy. 2024. "2024 year in review: leading the charge in geothermal innovation."
[8] Seven-to-ten years is documented by the U.S. Department of Energy (DOE) Pathways to Commercial Liftoff report and confirmed by the National Lab of the Rockies (NLR) Annual Technology Baseline, published in 2024. U.S. Department of Energy. 2024. "Pathways to commercial liftoff: next-generation geothermal power." See also: National Renewable Energy Laboratory. 2024. Annual Technology Baseline: geothermal.
[9] National Renewable Energy Laboratory. 2025. Enhanced geothermal systems and hydrothermal potential on federal lands. The assessment estimates 975 GW of technical EGS potential and 130 GW of hydrothermal potential on federal lands.

geophysical surveys, and slim-hole temperature gradient drilling can be completed in four to six months.[10] As noted below, these activities are covered by administrative categorical exclusions (CE).[11]

Phase 2: permitting and environmental review (months 1–18, concurrent with exploration). Because most geothermal developments occur on public land, the National Environmental Policy Act (NEPA) is a major timeline consideration. **A project on federal land can conceivably trigger NEPA review up to six separate times across the full development cycle: spanning land use planning, leasing, exploration, drilling, and utilization. The segmentation has no equivalent in oil and gas development under the Energy Policy of 2005**.[12] Requirements for the upstream stages, including resource management plan amendments and competitive lease review, remain intact. Post-leasing phases, however, have seen meaningful reform. BLM finalized categorical exclusions (CE) covering geothermal resource confirmation operations and exploration activities in early 2025; thus eliminating the previously required environmental assessment (EA) for those steps and, per DOE analysis, potentially removing up to a year from exploration permitting timelines.[13] In addition, DOI has implemented emergency permitting procedures under the Trump administration's national energy emergency declaration that would further compress post-leasing review windows, though those procedures remain subject to ongoing litigation.[14] Taken together, these reforms allow developers to front-load and consolidate NEPA processes across post-leasing phases in ways that were not available when the ten-year conventional development timeline was established.

There are two main steps in the NEPA process—exploration and development. In the **exploration stage**, operators can leverage CEs[15] recently adopted by BLM to cover geophysical surveys,

[10] National Renewable Energy Laboratory. 2024. Enhanced Geothermal Systems on Federal Lands: Technical Potential Assessment. NREL/TP-6A20-91848. Estimates 975 GW of technical EGS potential and 130 GW of hydrothermal potential on federal lands.
[11] Bureau of Land Management. Geothermal Energy. 43 C.F.R. Subpart 3207 (lease terms, extensions, and diligence expenditure requirements).
[12] U.S. Department of Energy. "GeoVision: Harnessing the Heat Beneath Our Feet—Analysis Supporting Task Force Report: Barriers." 2019. See also: DOE Geothermal Technologies Office, Permitting for Geothermal Power Development Projects.
[13] Bureau of Land Management. BLM Takes Steps to Accelerate Geothermal Energy Development. 2025. See also: Federal Register. NEPA Implementing Procedures for the Bureau of Land Management. 2024.
[14] Gravel2Gavel. Interior Department Streamlines NEPA, ESA, NHPA Reviews for Geothermal Energy Projects. 2025. See also: Harvard Environmental & Energy Law Program. NEPA — Department of the Interior.
[15] Recent CEs adopted by BLM include two interagency CEs in April 2024 from the U.S. Forest Service and the Department of the Navy (DON). In October 2024, the Department of the Interior (DOI) proposed a CE for geothermal resource confirmation and exploration activities that was finalized in January 2025. In January 2025 DOI proposed a CE for geothermal exploratory drilling activities that remains unfinalized. Both of the DOI CEs involved retroactive reviews of geothermal permits issued over the past 20 years which had received Findings of No Significant Impacts (FONSIs) and confirmed minimal impacts.

temperature gradient drilling, and resource confirmation activities. Thus, eliminating the need for a full EA of the site.[16] CEs usually take about two months to process; this should occur concurrently with the earliest part of Phase 1.

The most dramatic shifts in the permitting landscape have occurred in the **development stage**. This step should be completed with a single EA encompassing subsurface and surface development, as Fervo Energy demonstrated at Cape Station.[17] In the past, timeline uncertainty led to enormous delays in approvals for these projects; however, the Trump Administration has adopted emergency permitting procedures that are already having a dramatic effect on the industry. It is directing BLM to conduct NEPA **EAs within a shockingly fast 14 days, and environmental impact statements (EISs) in 28 days,** for strategically important projects. To highlight how aggressive these timelines are, Congress amended NEPA in 2023 to establish soft deadlines of one year for completing EAs and two years for completing EISs, and those time frames are roughly half the time actually taken previously.[18] While developers are not required to adopt this framework, three new projects have been permitted already with this framework, and at the most recent Geothermal Rising conference, Paul Thomsen, the VP of Development for Ormat, stated that this is the "best permitting environment in the U.S. in the last 35 years." Assuming the current permitting environment is maintained, and a Finding of No Significant Impact (FONSI) is executed, we estimate it will take **about one year** for developers to create a comprehensive Plan of Operations. This work can begin as soon as exploration phase work has been completed (month 7).

Phase 3: well drilling and reservoir creation (months 18—32 for a 100 MW project; months 18–48 for a 500 MW project). This phase is where EGS has made its most dramatic gains. As is typical in the oil and gas sector, Fervo Energy demonstrated that the repeated drilling of wells in an acreage leads to rapid drilling improvements. Fervo Energy's Cape Station drilling campaign, which began in June 2023, has now drilled 25 wells in approximately 20 months. The first wells took about 2.5 months each to complete; then, a rapid learning rate was realized until well #6, when per-well drilling time leveled out at about 20 days.[19] This results in the cost per foot of a well declining commensurately from roughly $1,000/ft to under $300/ft.

[16] Bureau of Land Management. Adoption of Categorical Exclusions Under Section 109 of the National Environmental Policy Act. 2024. See also: GRC CX. Federal Register notice. 2024.
[17] U.S. Department of the Interior. 2024. "Biden-Harris Administration Takes Major Steps to Accelerate Clean Energy Geothermal." The Cape Station EA covered subsurface and surface development in a single review, establishing the precedent for consolidated development-phase NEPA review.
[18] Holland & Hart. 2025. "State, federal incentives heat up geothermal projects." The NEPA reform legislation (Fiscal Responsibility Act, 2023) set soft deadlines of one year for EAs and two years for EISs. Historical completion times averaged roughly twice those targets.
[19] Fervo Energy. 2024. "Fervo Energy's record-breaking production results showcase rapid scale up of enhanced geothermal."

This "appraisal period" is required; it is also how commercial-scale projects can scale so fast. The slow progress in the first 6 months provides drillers the knowledge they need to move rapidly through the rest of the field. It is worth noting that the learnings in this phase, although unlikely, can uncover failure modes (such as the presence of existing natural fractures) that require more active mitigation, which would extend the timelines of development. In this model, we are assuming that serious failure modes are not encountered.

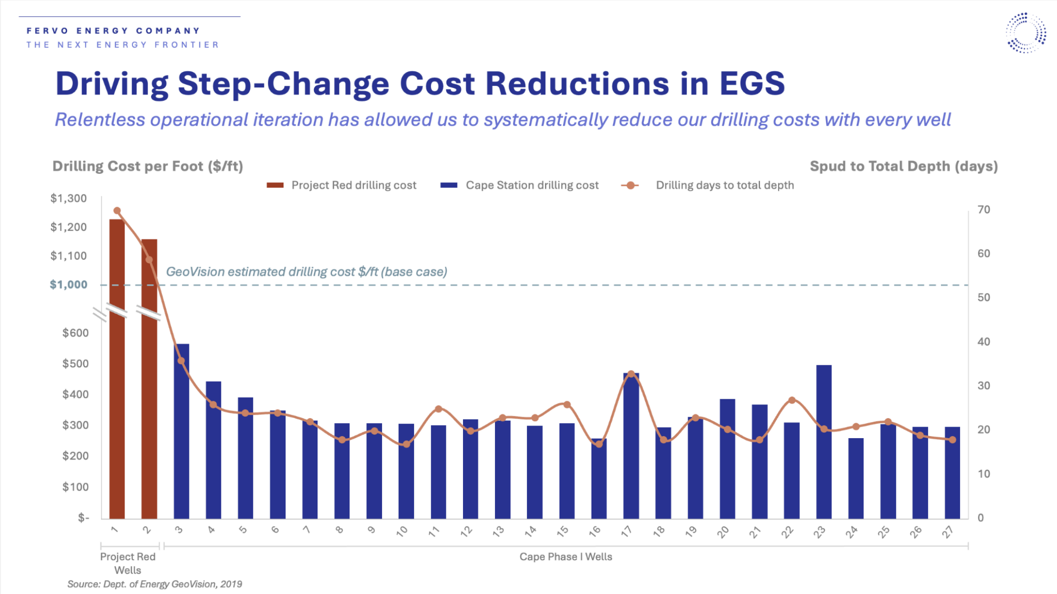

Figure 1. Fervo Energy Drilling Learning Curve: Spud to Total Depth, Project Red through Cape Station Phase I.[20]

Development time after this fixed six-month learning period is entirely dependent on a) the number of rigs operating, and b) the size of the field. EGS wells typically work in pairs, with about 10 MW of output expected per pair. So, for a **500 MW field**, about 100 wells are needed. Assuming that it takes about 20 days to drill a well, that developers can drill 4 wells on the same pad (without needing to move equipment), and that it takes 7 days to move equipment between pads, **three rigs will complete this commercial field in about 2.5 years**. However, adding an additional rig shaves a year off the process; adding two cuts another 6 months. Oil and gas companies typically have dozens of rigs on site at a given field; if geothermal operators were able to have 10 rigs simultaneously operating, **the entire 500 MW field could be appraised and drilled in about a year.** Smaller projects are drilled faster, and drill rig availability isn't as

[20] Fervo Energy Company (2026). Learning rate calculation from Schill et al. (2026). Chart shows actual drilling days (orange line, left axis) and cost per foot (bars, right axis) across 26 wells, spanning 2 Project Red pilot wells and approximately 22 Cape Phase I wells. Gray bars denote monobore trial wells. The revised learning curve (blue line) reflects a 29% learning rate, consistent with mature oil and gas drilling programs. Drilling times fell from over 70 days on early Project Red wells to approximately 20 days by mid-Cape Phase I, with cost per foot declining commensurately from roughly $1,000/ft to under $300/ft.

important. For a 100 MW project, one rig can drill the entire field in about 1.25 years, and 4 rigs can drill it in about a year. The modularity of the drilling process makes EGS a relatively fast path for a large generation source.

Phase 4: power plant construction (months 19 - 33 for a 100 MW project; months 19–48 for a 500 MW project). Binary Organic Rankine Cycle ("ORC") power plants are modular by nature. Units of six to eight MW each can be factory-manufactured during the drilling phase and rapidly assembled on site. Fervo's Cape Station Phase I uses Turboden (a Mitsubishi Heavy Industries subsidiary) ORC systems; Phase II has contracted Baker Hughes for five 50 MW units.[21] Engineering, procurement, and construction (EPC) for modular ORC plants typically requires 12–18 months from notice to proceed to commissioning. Grid interconnection studies and agreements should be pursued in parallel with permitting—ideally beginning in month 7, after exploration has been completed and when permits are being filed. A 500 MW facility will need approximately 10 50 MW units; a 100 MW facility will need two.

For this model, we assume that plants are built in alignment with wells being drilled, as the timelines for that process are relatively similar. Thus, a new plant is built every time 10 new wells are drilled. This assumption is contingent on the availability of crews and labor, as well as the status of interconnection.

Phase 5: Grid Interconnection to COD (months 33—36 for a 100 MW project; months 49—52 for a 500 MW project). Grid interconnection is the single greatest source of timeline uncertainty in any generation development—and the variable least within a developer's control. According to Lawrence Berkeley National Laboratory's *Queued Up* series, the median duration from interconnection request to commercial operation has more than doubled since the early 2000s, reaching five years for projects achieving COD in 2023.[22] EGS projects face this challenge acutely: geothermal resources are place-constrained, meaning developers cannot relocate to a faster queue point the way solar developers can, and remote project sites frequently require new or upgraded transmission infrastructure that utilities cannot easily justify for a single offtaker. Interconnection strategy must therefore begin no later than month 7; ideally informing site selection before drilling commences. Projects that reach plant commissioning without an active queue position risk a ready-plant, no-grid scenario that no phase of technical execution can resolve.

Parallel execution is essential

The 36—52 month timeline depends on aggressive parallelization of traditionally sequential activities. The following must occur concurrently: NEPA review begins with exploration; power plant EPC procurement and engineering start during drilling;off-site ORC manufacturing

[21] Baker Hughes. 2025. "Baker Hughes selected by Fervo Energy to deliver geothermal power generation equipment for innovative new power plants."
[22] Lawrence Berkeley National Laboratory. 2025. Queued Up: 2025 Edition, Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2024.

proceeds while wells are being drilled and stimulated; and grid interconnection studies run in parallel with permitting from the outset. Sequential execution of these phases yields the conventional seven-to-ten-year timeline. Parallel execution—enabled by EGS's reduced exploration risk and modular power plant design—compresses it to three years.

The biggest potential bottleneck to accomplishing this timeline is not related to geothermal technology. **Rather, *access to transmission and interconnection* is the most likely reason that an EGS project would come online more slowly than projected.** When asked to list the top one or two barriers they face to deployment, leading next-generation geothermal developers list transmission and interconnection, with most developers stating that it is the single biggest barrier they face. Historically, slow permitting timelines have been another major barrier, but recent action from the Biden and Trump administrations (see Phase 2 above) to streamline and prioritize geothermal permits have dramatically reduced uncertainty in geothermal permitting. The good news is that both interconnection and permitting are solvable problems. Focused attention from policymakers can address these issues and ensure that geothermal is able to deploy on the shorter timelines described above.

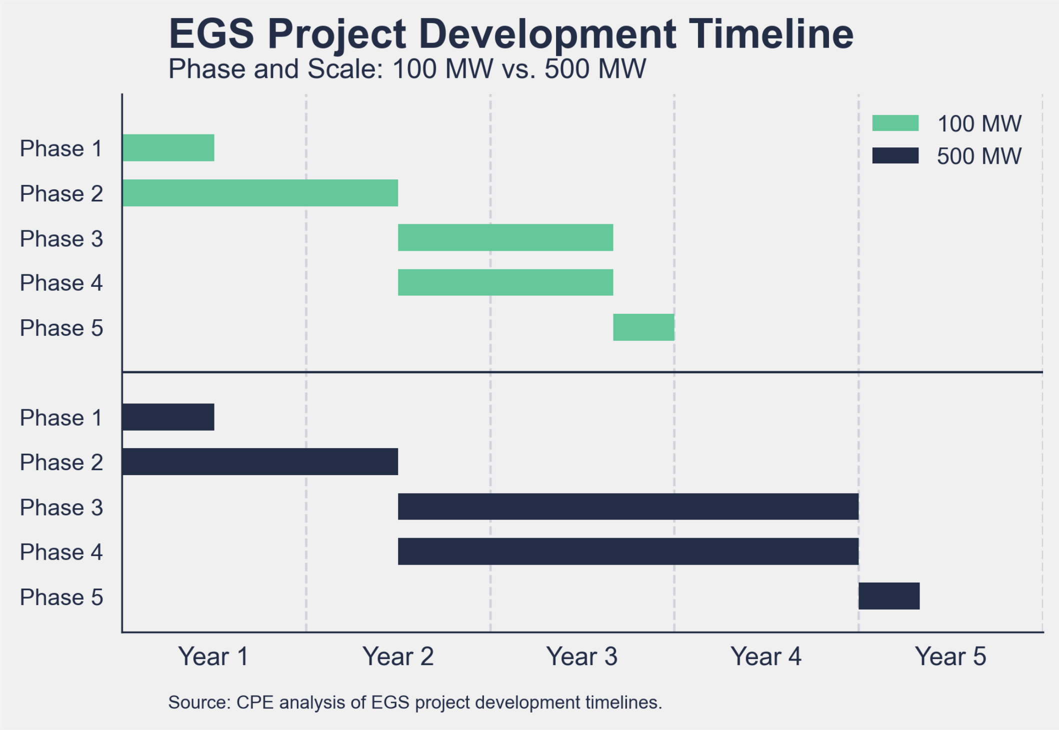

Figure 2. EGS Project Development Timeline.[23]

[23] Data and script available upon request.

III. Fervo Energy's Cape Station: The industry benchmark

Cape Station, located in Beaver County, Utah—approximately 12 miles northeast of Milford, adjacent to DOE's Frontier Observatory for Research in Geothermal Energy (FORGE) site—is the world's first commercial-scale EGS project and the most important data point for validating the development timeline described above. It is, however, not a perfect analogue, as much of the initial resource exploration and confirmation work that a developer would have needed to do had been completed by activities at the FORGE site. The FORGE program, which has operated (primarily for research and development) since 2015 and received over $218 million in federal funding, generated a comprehensive public dataset covering subsurface temperature gradients, rock mechanics, stress orientation, permeability, fracture characterization, and hydraulic stimulation results across multiple deep wells—all freely available on DOE's Geothermal Data Repository.[24] These datasets recorded over 23,000 downloads in the first half of 2024 alone, underscoring their value to the broader development community. Fervo's CEO acknowledged directly at the Cape Station groundbreaking that FORGE data allowed the company to accelerate production of the region's geothermal resources.[25] Cape Station also benefits from an existing seismic monitoring network of seventeen permanent stations installed by FORGE, and from proximity to the Blundell geothermal power plant, which provided additional reservoir data.[26] Collectively, these advantages allowed Fervo to effectively skip Phase 1 of the project development timeline described above, saving approximately ten months and reducing development timeline from an estimated 46 months to the 36 months observed at Cape Station.

Key milestones

From BLM EA approval in February 2023, Cape Station moved rapidly into development. Following secondary permitting—including a county conditional use permit and individual drilling permits from BLM and the Utah Division of Water Rights—appraisal drilling began in June 2023. Fervo held a formal groundbreaking ceremony in September 2023, attended by federal, state, and local officials, to mark the public launch of the exploration drilling campaign. By February 2024, Fervo had published drilling results at the Stanford Geothermal Workshop demonstrating a 70 percent reduction in drilling time compared to its Project Red pilot.[27] In September 2024, the company's Technology Day revealed that 15-plus wells had been drilled and a 30-day flow test had been completed, achieving flow rates of 107 kilograms per second and

[24] Utah FORGE. Data Dashboard. See also: U.S. Department of Energy Office of Geothermal. FORGE.
[25] Fervo Energy. Fervo Energy Breaks Ground on the World's Largest Next-Gen Geothermal Project. 2023.
[26] Fervo Energy. Fervo's Approach to Induced Seismicity Management. See also: Fervo Energy. Cape Station.
[27] Lawrence Berkeley National Laboratory. Queued Up: 2025 Edition, Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2024. 2025.

more than ten MW of electric equivalent output per well.[28] Power plant construction broke ground in October 2024, the same month BLM issued final development approval. Phase I: 100 MW is targeted for commercial operation in late 2026, representing approximately 40 months from the start of appraisal drilling to first power.[29]

The project was originally designed for 400 MW and upsized to 500 MW in April 2025 after an independent reserve report by DeGolyer & MacNaughton confirmed the project area can support over five GW at depths to 13,000 feet. BLM has permitted development of up to two GW at the site. All 500 MW are fully contracted: 320 MW to Southern California Edison under 15-year power purchase agreements (PPAs)—the world's largest geothermal PPAs—31 MW to Shell Energy, 53 MW to California community choice aggregators, and additional contracts with Clean Power Alliance.[30]

Drilling performance breakthroughs

Cape Station's drilling results demonstrate the shale-industry learning curve applied to geothermal. Well costs dropped from $9.4 million to $4.8 million—a 49 percent reduction—across the first four wells.[31] Drilling time fell from approximately 70 days per well at Project Red (2022) to sub-20 days at Cape Station (2024) to just 16 days for the Sugarloaf appraisal well in June 2025, which reached 15,765 feet true vertical depth at temperatures of 520°F (271°C) with an average rate of penetration of 95 feet per hour.[32] Because drilling accounts for more than 75 percent of total well costs, continued time reductions translate directly into cost declines. Fervo's realized learning rate of 35 percent exceeds its planned 18 percent—a faster cost curve than the shale revolution achieved at comparable stages.[33]

What Cape Station means for IRP planning

From active development start (June 2023 drilling) to expected Phase I COD (late 2026), Cape Station demonstrates a roughly 40-month timeline. From groundbreaking to COD, the timeline is approximately 36 months. However, as mentioned above, data and methods learned from drilling at the DOE-funded Utah FORGE site provided Fervo with a significant head start. DOE's

[28] Fervo Energy. 2024. "Fervo Energy drilling results show rapid advancement of geothermal performance."
[29] Fervo Energy. 2024. "Fervo Energy's record-breaking production results showcase rapid scale up of enhanced geothermal."
[30] Fervo Energy. 2025. "Fervo Energy secures $206 million in new financing to accelerate Cape Station development."
[31] Fervo Energy. 2024. "Fervo Energy announces 320 MW power purchase agreements with Southern California Edison." See also: Fervo Energy. 2025. "Fervo Energy announces 31 MW power purchase agreement with Shell Energy."
[32] Fervo Energy drilling results. See note 28.
[33] Fervo Energy. 2025. "Fervo Energy drills 15,000-ft, 500°F geothermal well." See also: ThinkGeoEnergy. 2025. "Fervo further demonstrates EGS scalability with Cape Station appraisal well."

work at FORGE had a wide R&D-focused remit that included developing and testing new drilling methods and tools for the first time; however, in that process, they also provided Fervo with the data needed to fully characterize the site and effectively skip phase 1 in our outlined timeline. Based on these assumptions, Fervo's Cape Station development timeline would actually be 46 months, slightly longer than our outlined process.

Given that Cape Station is the first commercial-scale EGS facility in the world, it is reasonable to assume that subsequent projects, benefiting from established drilling techniques, supply chain relationships, and workforce experience, should compress further. For IRP modeling purposes, a reasonable planning assumption of **three to six years** from development initiation to in-service captures both the demonstrated Cape Station timeline and its associated head starts, as well as reasonable contingency for site-specific permitting or interconnection delays.

IV. EGS and the resource portfolio: Complementing solar, wind, and storage

EGS complements solar photovoltaics (PV), wind, and battery energy storage systems (BESS) by filling the structural gap that variable renewables and short-duration storage cannot address: reliable, around-the-clock generation that persists through multi-day weather events, seasonal variation, and evening demand peaks.

EGS is an example of "clean firm" power, defined as "dispatchable, low-emission electricity generating resources that do not rely on the weather [and can] generate clean power on demand for an effectively indefinite period of time."[34] Clean firm power is particularly valuable because the amount of variable renewable capacity required to ensure grid reliability scales non-linearly; as the grid penetration of variable renewables (even with storage) increases, the additional amount of capacity needed for further grid penetration also increases. To put it another way: there are diminishing marginal returns to deploying variable renewables as grid penetration increases. Variable renewables can cost-effectively support large amounts of decarbonization, but taking a grid to full decarbonization using only variable renewables and storage would require an enormous buildout of these energy sources.

Arizona's load growth is accelerating faster than its planned firm capacity additions can match. Demand requests from large energy users alone now exceed 19,000 MW. This is more than double APS's 2025 peak demand record—driven by data centers, manufacturing, and continued population growth.[35] To meet this demand, Arizona utilities are retiring coal capacity, deploying solar and storage aggressively, and exploring new nuclear generation. But new nuclear—whether large reactors or SMRs—carries a development timeline exceeding a decade by utilities' own estimates, and coal retirements at Four Corners and Cholla are removing gigawatts of dispatchable baseload that solar and four-hour battery storage cannot fully replace across multi-day low-generation events.[36] Next-generation geothermal offers firm, dispatchable capacity that can be online in three to four years.

Clean firm energy solves the problem of diminishing marginal returns to variable renewable deployment and is consistently highlighted across a wide range of models for its value to decarbonized and decarbonizing grids. Variable renewables (often paired with storage) remain

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[34] Clean Air Task Force. "Clean Firm Electricity Technologies: What, Why, How." 2026.
[35] APS. "APS Uses 'Growth Pays for Growth' Model to Develop New Natural Gas Plant." 2025.
[36] ACC IRP Workshop. How Arizona Regulated Utilities Plan to Power Arizona's Future. 2024. See also: Arizona Public Service, Salt River Project, Tucson Electric Power. Joint statement on nuclear exploration. 2025. See also: POWER Magazine. 2024. "How the Vogtle nuclear expansion's costs escalated;" World Nuclear News. 2024. "EDF announces Hinkley Point C delay and rise in project cost;" World Nuclear News. 2023. "Idaho SMR project terminated;" E&E News. 2023. "NuScale cancels first-of-a-kind nuclear project as costs surge."

the majority energy sources in essentially all models, and decarbonization scenarios require a rapid expansion of these energy sources (as well as transmission). However, clean firm power provides an important complement to variable renewable energy, reducing the total infrastructure needs of a decarbonized grid, reducing power price volatility, and significantly decreasing ratepayer costs. A review of 40 studies on deep decarbonization modeling from 2015 to 2021 found that clean firm options could reduce ratepayer costs for power sector decarbonization by 30-65 percent depending on model specifications.[37] Importantly, clean firm power is cost-effective even under "optimistic assumptions of continued cost declines for variable renewables and lithium-ion battery storage, large-scale transmission expansion, and widespread demand-side technology adoption, all of which are typically incorporated in power system studies."[38]

Clean Air Task Force (CATF) modeling of the Western Interconnection found that covering a 68-day renewable shortage period would require 33 terawatt-hours (TWh) of storage—"extensive infrastructure at high cost, most of which is only used one time per year."[39] Clean firm resources like EGS directly mitigate this need. They reduce the over-build of wind and solar capacity required to achieve reliability targets, reduce transmission expansion (by up to three times in some California modeling scenarios), and reduce dependence on long-duration storage.

For IRP purposes, how a resource is credited for firm capacity matters as much as its nameplate rating, and that determination ultimately rests with grid regulators and the methodologies they adopt. A geothermal plant operating at a capacity factor above 80 percent typically receives a qualifying capacity credit of 80–85 percent, comparable to conventional thermal generation. Unlike variable renewables, whose capacity credits are calculated through probabilistic ELCC modeling and decline sharply as penetration increases, geothermal qualifying capacity is based on historical production during peak hours and remains stable over time. System modeling consistently finds that this high capacity credit means geothermal can meet the same reliability requirement with significantly less installed capacity than solar-plus-storage: analysis by the CPUC found that **one MW of geothermal reduced the need for three to five MW of solar-plus-storage** in least-cost portfolio optimization, a finding that informed its subsequent adoption of a preferred portfolio including 1.7 GW of new geothermal.[40] This does not imply that geothermal will displace solar and storage, as both will have substantial roles on the Western grid. It does mean, however, that adding geothermal to a portfolio improves overall system efficiency. As CATF's recent analysis of clean firm generation concludes, diversified power

[37] NorthBridge Group for Clean Air Task Force. 2021. Deep decarbonization literature review: a review of 40 studies from 2015 to 2021. The review found that clean firm options could reduce ratepayer costs for power sector decarbonization by 30–65 percent depending on model specifications.
[38] Clean Air Task Force. "Clean Firm Electricity Technologies: What, Why, How." 2026.
[39] Clean Air Task Force. 2023. "We need clean firm electricity for a decarbonized energy system."
[40] Ibid.

systems that include clean firm resources are significantly less expensive than systems relying almost exclusively on variable renewables, often by tens of percent, even under optimistic assumptions about future renewable cost declines. A 200 MW geothermal contract therefore does not compete with solar; it reduces how much solar and storage the broader portfolio needs to carry to meet the same reliability standard.[41]

V. Cost trajectory and economic case

EGS is not yet the cheapest resource on a levelized cost basis—but its cost trajectory, combined with its firm capacity value, makes the economic case increasingly strong.

The Energy Information Administration's (EIA) Annual Energy Outlook 2025 projects a geothermal levelized cost of **$37.58 per MWh** for plants entering service in 2030, inclusive of federal tax credits—lower than advanced nuclear ($81.45), gas combined cycle ($64.55), gas peaking ($133.88), and solar-plus-storage ($53.44).[42] Lazard's unsubsidized LCOE analysis (version 17.0, 2024) places conventional geothermal at $64–102 per MWh, compared to $102–225 for nuclear new-build.[43] The DOE's Enhanced Geothermal Shot, launched in September 2022, targets a further reduction to **$45 per MWh by 2035**—a 90 percent decline from 2020 costs.[44]

Fervo's drilling data underpin this trajectory. Well costs fell 49 percent across the first four Cape Station wells. NLR updated its drilling cost assumptions downward by 24–26 percent from GeoVision estimates based on recent field data.[45] EGS costs are following a learning curve analogous to the shale revolution—where costs per lateral foot declined roughly 50 percent over the first decade of horizontal drilling—and Cape Station is still only the first commercial EGS project.

Importantly, LCOE comparisons alone are inadequate for firm resources. The DOE Liftoff Report emphasizes that "comprehensive system studies show grids with diverse firm power achieve lower overall costs even when individual resource LCOEs are higher."[46] A utility that procures only the cheapest individual resources—solar and batteries—may face higher total system costs when

[41] U.S. Energy Information Administration. Capacity Factors for Utility Scale Generators. 2023. See also: California Public Utilities Commission. 2020 Qualifying Capacity Methodology Manual. 2020. The 1-to-3–5 MW displacement ratio derives from CPUC least-cost portfolio optimization modeling that informed its subsequent adoption of a preferred portfolio including 1.7 GW of new geothermal.
[42] U.S. Energy Information Administration. 2025. Levelized costs of new generation resources in the Annual Energy Outlook 2025.
[43] Lazard. 2024. Lazard's levelized cost of energy plus, version 17.0.
[44] U.S. Department of Energy. 2022. "DOE launches new energy earthshot to slash the cost of geothermal power."
[45] National Renewable Energy Laboratory. 2024. Annual Technology Baseline: geothermal.
[46] U.S. Department of Energy. 2024. Pathways to commercial liftoff.

forced to address reliability through over-build, long-duration storage, or emergency gas procurement during extended weather events.[47] This is because LCOE does not consider various aspects of a technology's generation profile, including characteristics like inertia and dispatchability as well as the full system cost of deployment (i.e., including transmission and distribution infrastructure. These omissions make LCOE an imperfect metric to evaluate a project's full value to the energy system—especially in the context of "long-term system and deep decarbonization planning, clean energy technology value assessment, and supplying the recent surge in load growth forecasts."[48]

Federal tax advantages

The Inflation Reduction Act (IRA) provides EGS with structurally favorable tax treatment. The 30 percent ITC (with prevailing wage and apprenticeship compliance) is available to geothermal projects that begin construction before January 1, 2035.[49] The One Big Beautiful Bill Act of 2025 accelerated the phase-out of the solar and wind ITC to a construction commencement date of July 4, 2026 or a placed-in-service date of December 31, 2027—giving geothermal a **full decade of additional ITC eligibility** beyond wind and solar.[50] Bonus adders of ten percent for domestic content and ten percent for energy communities can push the total geothermal ITC above 50 percent. For a capital-intensive EGS project at $5,000 per kilowatt, a 30 percent ITC yields $1,500 per kilowatt in tax benefit—a substantial offset to front-loaded development costs. The Production Tax Credit (PTC) alternative offers approximately $30.00 per MWh (2025 value, annually inflation-adjusted) for the first ten years of operation.

[47] Clean Air Task Force. 2025. Beyond LCOE: Assessing the Full Value of Clean Electricity Resources. The report identifies inertia, dispatchability, and full system infrastructure costs as the primary omissions from standard LCOE calculations.
[48] Ibid.
[49] U.S. Environmental Protection Agency. "Summary of Inflation Reduction Act provisions related to renewable energy." See also: "IRA Section 13102—Renewable Energy Investment Tax Credit."
[50] Grant Thornton. 2025. "Energy incentives under OBBBA: what you need to know."

VI. Arizona's geothermal resource base: 55 GW untapped

The demand surge facing Arizona utilities is acute, but the underlying pressure is regional. The Northwest Power and Conservation Council's 2025 load forecast projects annual electricity demand across Oregon, Washington, Idaho, and Montana to grow from roughly 22,000 average megawatts today to between 31,000 and 44,000 average megawatts by 2046, driven by data centers, chip fabrication, and electrification.[51] In Colorado, Xcel Energy's Colorado subsidiary initially projected a 19 percent increase in peak demand to 8.6 GW by 2031, projecting that large-load customers including data centers would account for two-thirds of new electricity demand and require up to 12,000 to 14,000 MW of new generation to keep pace.[52] NERC's 2025 long-term reliability assessment found that parts of the Pacific Northwest face elevated risk of insufficient reserve margins within five years, with near-term resource additions there predominantly solar, resulting in a more variable resource mix.[53] Across the West, the pattern is consistent: load is growing faster than firm capacity, and the pipeline of dispatchable resources is too thin, too slow, or both.

While each state has expectations of growth, Arizona is ground zero for this region's load growth. Arizona's three major utilities set record demand peaks in August 2025—Arizona Public Service (APS) reached 8,631 MW, Salt River Project (SRP) hit 8,542 MW, and the state's second-largest investor-owned utility exceeded 2,500 MW—each surpassing their own 2025 forecasts.[54] Arizona's total electricity demand grew eight percent in 2025, roughly four times the national average, driven overwhelmingly by data centers that accounted for 94 percent of demand growth for APS between 2023 and 2025.[55] The state hosts over 140 data centers with approximately 707 MW of information technology capacity, and APS alone has 4,000 MW of extra-high-load-factor customers in construction or coming online, with an additional 10,000-plus MW in its planning pipeline.[56]

This demand surge arrives just as Arizona retires its remaining coal generation—scheduled for a majority phase-out by 2031—while natural gas, which supplies 47 percent of the state's electricity, faces rising costs. The Lazard Levelized Cost of Energy Plus (LCOE+) analysis, version 18.0 (June 2025), found that gas-fired generation costs reached a ten-year high due to turbine shortages

[51] Northwest Power and Conservation Council. Initial 20-Year Forecast for Pacific Northwest Electricity Demand. 2025.
[52] Jaffe, Mark. "More data centers are coming to Colorado, demanding more power than they'll need." The Colorado Sun. 2025.
[53] Walton, Robert. "NERC forecasts peak demand to rise 24% on new data center loads." Utility Dive. 2026.
[54] Arizona Corporation Commission. 2025. "Arizona electric utilities set record high demand—again—demand soars above original forecasts for 2025."
[55] Caughill, Patrick. "Data centers are pushing Arizona's grid to the limit." Distilled.
[56] Ibid.

and supply chain pressures.[57] Meanwhile, the Arizona Corporation Commission (ACC) has signaled its regulatory priorities clearly: reliability, affordability, and technology-neutral procurement. The ACC voted unanimously in August 2025 to begin formal repeal of the 2006 Renewable Energy Standard, and in 2022 rejected a proposed 100 percent clean energy standard.[58] What the ACC does demand—per Decision No. 75068—is that utilities demonstrate "sufficient dependable/dispatchable capacity" in their IRPs, including analysis of expanded renewables "including geothermal."[59]

EGS occupies a unique position in this regulatory environment. It is firm, dispatchable, and baseload—the qualities that utility commissions like ACC generally value most—while also being zero-carbon, zero-fuel-cost, and supported by bipartisan federal policy. It does not require a new gas pipeline or an NRC license. And recent developments suggest drastically reduced project timelines, coming online in as little as three years. Critically, approximately 20 percent of Arizona is state trust land, where projects can bypass the federal NEPA process entirely—a significant timeline advantage. The tradeoffs are real and specific, however. Arizona State Trust Land is administered by the Arizona State Land Department (ASLD), which has not issued a geothermal lease since the mid-1980s, meaning any EGS project on state land would face an agency with no modern institutional experience with geothermal permitting.[60] Long-term commercial leases require competitive public auction under Arizona law, with no guaranteed timeline to award.[61] Developers must also secure county rezoning before auction can proceed, a process ASLD itself notes can take up to 18 months.[62] The net effect is that the NEPA bypass advantage of state trust land is real, but it comes with a different set of delays: an untested geothermal leasing pathway, mandatory auction procedures, and local zoning requirements that must be resolved sequentially before development can commence.

Arizona is well-positioned for a geothermal expansion. Though the state has no operating geothermal power plants at the moment, Arizona possesses **54,700 MW of mean EGS potential**—the fourth-highest among Mountain West states—according to the USGS 2008

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[57] Lazard. 2025. Lazard's levelized cost of energy plus, version 18.0.
[58] Arizona Corporation Commission proceedings, 2022–2025. See also ACC Decision No. 75068; ACC voted unanimously in August 2025 to begin formal repeal of the 2006 Renewable Energy Standard.
[59] Ibid.
[60] U.S. Nuclear Regulatory Commission. "NEIMA milestone schedules of requested activities."
[61] Long-term agreements on Arizona State Trust Land require competitive bidding through public auction, per Arizona State Land Department leasing rules. Lincoln Institute of Land Policy. A.R.S. § 37-281.02. Commercial leases exceeding 10 years must be awarded to the highest and best bidder at public auction.
[62] Arizona State Land Department. Solar Applications. County zoning may take up to 18 months to achieve and must be secured in advance of the lease auction). Although this guidance addresses solar applications specifically, ASLD applies the same sequencing requirement to all commercial energy leases on state trust land.

national geothermal resource assessment.[63] Most of southern and western Arizona lies within the Basin and Range physiographic province, characterized by elevated heat flow of 80–90-plus milliwatts per square meter (mW/m²)—significantly above the global continental average of approximately 65 mW/m²—resulting from thin crust produced by extensional tectonics.[64] Temperature gradients of 30–50-plus °C per kilometer are common across the region, meaning temperatures of 150–250°C suitable for electricity generation occur at drillable depths of three to six kilometers. Known geothermal areas include the Clifton area near the New Mexico border (investigated by APS under a DOE grant), the San Francisco Volcanic Field near Flagstaff, southeastern Arizona Basin and Range prospects, the Safford Basin, and thermal anomalies in the Tucson Basin with reservoir temperatures estimated at 80–140°C.[65]

The broader Mountain West geography holds an even larger prize. Across Idaho, Arizona, Colorado, Nevada, New Mexico, Wyoming, and Utah, the USGS estimates approximately **384 GW of EGS potential**—roughly 74 percent of the national total.[66] A provisional 2025 USGS assessment of the Great Basin alone found 135 GW of EGS capacity in the upper six kilometers.[67] The region is ripe for geothermal exploration. Project development barriers are now the greatest hurdle to utilizing the resource—and can be overcome.

[63] Arizona State Land Department. Subsurface Leases and Permits. ASLD has not issued a geothermal lease since the mid-1980s.
[64] Southern Methodist University Geothermal Laboratory. "Heat flow data and maps." See also: U.S. Department of Energy Office of Scientific and Technical Information. Arizona geothermal technologies program.
[65] Arizona Geological Survey. "Geothermal in Arizona." See also: Core. "Geothermal resource potential of the Tucson Basin, Arizona."
[66] Williams, C., et al. 2008. Assessment of moderate- and high-temperature geothermal resources of the United States. U.S. Geological Survey Fact Sheet 2008-3082. Calculation by CPE from state-level data.
[67] U.S. Geological Survey. 2025. Enhanced geothermal systems electric-resource assessment for the Great Basin, southwestern United States.

VII. Recommended IRP modeling parameters

Parameter	Recommended value	Basis
Resource type	Enhanced geothermal system (EGS)	—
Commercial availability (in-service date)	**2030–2034** (development starting 2027–2029)	Analysis in this paper (highly variable dependent on project size)
Nameplate capacity per block	**100–500 MW**	Cape Station Phase I = 100 MW; full build = 500 MW
Capacity factor	**~80 percent**	DOE, NLR ATB, Fervo demonstrated >80 percent
ELCC / capacity credit	**~80–85 percent**	Comparable to conventional thermal generation
Forced outage rate	2–5 percent	Industry standard for binary ORC plants
Planned outage rate	2–4 percent	Industry standard
Economic life	**30 years**	NLR ATB default; reservoirs may exceed 40 years
Heat rate / fuel cost	**$0 per MMBtu** (no fuel input)	Permanent fuel cost hedge
Capital cost (overnight)	$3,000–6,000 per kW (declining)	DOE Liftoff; NLR ATB 2024
Fixed O&M	$20–40 per kW-year	NLR ATB 2024
Variable O&M	$0–3 per MWh	NLR ATB 2024
Construction duration	**3–6 years** (conservative); 30–36 months optimistic	Cape Station demonstrated
LCOE (2030, with ITC)	**$37–70 per MWh**[68]	EIA AEO 2025; DOE trajectory
Temporal generation profile	**Flat / semi-flat** (no weather correlation)	24/7/365 baseload; no seasonal derates

Table 1. Recommended IRP Modeling Parameters for Enhanced Geothermal Systems in the Mountain West

[68] The LCOE range reflects two distinct methodologies. The lower bound ($37.58/MWh) is the simple average for geothermal plants entering service in 2030 inclusive of federal tax credits, per U.S. Energy Information Administration, *Levelized Costs of New Generation Resources in the Annual Energy Outlook 2025*. EIA does not model EGS as a separate technology class; the figure reflects conventional geothermal assumptions in the National Energy Modeling System. The upper bound ($70/MWh) is the unsubsidized near-term target for commercial EGS by 2030, per U.S. Department of Energy, *Pathways to Commercial Liftoff: Next-Generation Geothermal Power* (2024). The range is kept broad to capture both the subsidized conventional baseline and the unsubsidized EGS cost trajectory, which DOE projects will decline toward the Enhanced Geothermal Shot target of $45/MWh by 2035.

For utilities evaluating EGS as a candidate resource in IRP optimization models, the following parameters represent defensible, evidence-based inputs derived from Fervo's Cape Station data, DOE projections, and NLR's Annual Technology Baseline.

The flat temporal profile is a critical differentiator. Unlike solar, which produces zero output during evening and nighttime hours and varies seasonally, geothermal gross output is largely independent of weather conditions and maintains consistent generation across all 8,760 hours of the year. Net output can vary modestly with ambient temperature—particularly for binary-cycle plants using air-cooled condensers, where high summer temperatures increase parasitic load and reduce condenser efficiency–but this variation is small relative to the seasonal swings that are characteristic of solar and wind. This characteristic makes geothermal uniquely valuable in optimization models that enforce reliability constraints, particularly for utilities serving 24/7 data center loads.

VIII. Policy landscape and federal support

EGS enjoys rare bipartisan support. The DOE Office of Geothermal administers several programs that directly reduce development risk and cost. Utah FORGE—the Frontier Observatory for Research in Geothermal Energy—has received $218 million-plus in federal funding and achieved critical milestones including successful multi-stage hydraulic stimulation, confirmed well connectivity, commercial-scale stimulation with greater than 67 percent water recovery, and minimal induced seismicity (maximum M1.9).[69] The DOE awarded Fervo a $25 million grant for Cape Station in April 2024, the largest single Geothermal Technologies Office award in history, and announced $60 million for three additional EGS pilot projects in May 2025.[70] Most recently, in February 2026, DOE released a notice of funding opportunity (NOFO) committing up to $171.5 million for next-generation geothermal field tests and resource characterization drilling, the largest single tranche of federal geothermal funding ever announced. Up to $100 million targets early commercial-scale EGS field tests across diverse geologic settings, with the explicit goal of generating the performance data that project finance and infrastructure investors require to deploy capital at scale. DOE's own analysis projects that this class of investment could unlock $20–25 billion in new private investment and 5–10 GW of new firm power within five years.[71]

The DOE Liftoff Report projects that the U.S. grid will need 700–900 GW of additional clean firm capacity by 2050; next-generation geothermal could provide 90 GW, with up to 300 GW when

[69] Utah FORGE and DOE Office of Geothermal. Utah FORGE milestones and results. See also: University of Utah. "Breakthrough at FORGE."
[70] U.S. Department of Energy Office of Geothermal. Funding Notice: Next-Generation Geothermal Field Tests and Geothermal Resource Characterization and Confirmation (NOFO DE-FOA-0003472. 2026. See also: O'Connor, Michael. Geothermal demonstrations get their day. 2026. Center for Public Enterprise.
[71] U.S. Department of Energy. 2024. Pathways to commercial liftoff.

accounting for storage capabilities. NLR's Enhanced Geothermal Shot analysis projects 90 GW of installed capacity by 2050, supplying up to 12 percent of U.S. electricity.[72]

The Trump administration's "Unleashing American Energy" executive order explicitly supports geothermal development. BLM geothermal lease auctions in 2025 resulted in record-setting sales in Nevada, Utah, California, Idaho, and Oregon. BLM geothermal lease auctions are scheduled for 2026 in Utah, New Mexico, and Idaho. Additionally, updated BLM guidance released in December 2025 requires annual geothermal lease sales when there are pending parcel nominations. U.S. Energy Secretary Chris Wright, formerly CEO of Liberty Energy, invested $10 million in Fervo through Liberty prior to his appointment—indicating that executive branch leadership is aware of the potential of enhanced geothermal systems.[73] The oil-and-gas workforce transferability of EGS aligns with both parties' domestic energy and jobs priorities.

To ensure that EGS can scale and deploy at the pace laid out in this report, additional policy work will be necessary—particularly related to transmission access and permitting clarity.

IX. Conclusion: The bottom line for Western utility resource planners

Next-generation EGS can deliver 100–500 MW of clean, firm, dispatchable baseload power with a **construction timeline of three to five years** and a **target in-service date of 2030–2034** for projects initiating development in 2027–2029. This timeline is validated by Fervo Energy's Cape Station, which is on track to bring 100 MW online approximately 36 months after groundbreaking—the fastest clean firm resource addition available to western utilities today.

For utilities preparing IRP filings that must demonstrate reliable, dispatchable capacity to state regulators, EGS offers three structural advantages no other clean resource can match. First, a capacity factor above 80 percent and an ELCC of 80–85 percent mean that one MW of geothermal replaces three to five MW of solar-plus-storage in capacity planning—the most efficient firm resource addition in the model. Second, zero fuel cost provides a permanent hedge against the gas price volatility that has driven gas-fired LCOE to a ten-year high. Third, the IRA's 30 percent ITC for geothermal extends through 2035—a full decade beyond solar and wind—creating a durable investment signal that de-risks long-term procurement.

The Mountain West holds 384 GW of EGS potential across seven states. Arizona alone possesses 55 GW—enough to power the state's entire grid many times over—with favorable

[72] National Renewable Energy Laboratory. 2023. Enhanced geothermal shot analysis: modeling a pathway to $45/MWh.
[73] U.S. Department of Energy. 2024. Pathways to commercial liftoff. See also: Fervo Energy. 2024. "2024 year in review."

geology, significant state trust land that bypasses federal permitting, and surging demand from data centers that require exactly the 24/7 baseload profile geothermal provides. The resource is there. The technology is proven. The question is no longer whether EGS can be built at scale, but whether western utilities will move fast enough to capture its value in their next resource plans.

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