PROCEEDINGS, 51st Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 9-11, 2026
SGP-TR-230

Why an Open-Source Approach to Technical Knowledge Sharing is Crucial for Rapidly Expanding Geothermal's Share of the Power Production Market

Greg Leveille

ConocoPhillips (retired); currently Tidal Wave Technologies

greg@tidalwavetechnologies.com

Keywords: Geothermal power production, open-source knowledge sharing, collaboration, economics, rapid growth, market share

ABSTRACT

Interest in geothermal power production has increased substantially over the past five years as technology transfer from the oil and gas industry has driven down the cost of extracting heat from the Earth's crust, established geothermal industry participants have developed both a better understanding of the nature of geothermal systems and better exploration tools, and the data center building boom has resulted in premium pricing for clean, firm power. While this has generated a modest amount of additional investment in geothermal power projects, further performance improvements are needed for geothermal to secure a significant percentage of the U.S. and international power production markets. That rapid growth in market share could be achieved is suggested by the pace of growth realized over the past twenty-five years from both Canadian Steam Assisted Gravity Drainage (SAGD) oil sands projects and U.S. unconventional reservoirs. These two segments of the oil and gas industry had been technically and economically challenged, but after having received government support in the latter parts of the twentieth century, grew quickly thereafter as operating companies took the lead in driving innovation forward.

The growth in U.S. unconventional production to over twenty-five million barrels of oil equivalent per day by YE 2024 is a particularly compelling example for the geothermal industry to learn from. One of the principal factors that enabled this outcome was the transfer of technical knowledge between operators. This was crucial because it allowed companies to learn from each other's mistakes, difficulties, experiments, and successes, thereby vastly reducing the time and funding required to make progress in driving down development costs and increasing per well production rates. Although much of this sharing of knowledge was at first unintentional, resulting from a pseudo-open-source ecosystem wherein knowledge disseminated mostly through back-channels at a modest pace, the late 2014 collapse in oil prices encouraged companies to recognize that creating formal open-source knowledge sharing structures would benefit not only the industry as a whole but their company in particular. Examples of the types of structures that were put in place include joint operator/government funded hydraulic fracturing test sites, company-to-company and multi-company data trades, publication of cutting-edge technical papers, operator involvement with technology start-ups, and industry-wide adoption of standards for the disclosure of certain types of technical data.

While the geothermal community has already embraced some of these methods for sharing technical knowledge and the cost of technology demonstration projects, because the geothermal industry is tiny compared to other better established energy production industries, companies within the geothermal industry would benefit considerably from increasing the amount of knowledge and cost sharing taking place. This would allow established companies to improve their profitability by learning faster than they could on their own, leading to the capture of untold millions of dollars of profit margin that would otherwise be lost. Sharing would also encourage new participants to invest in geothermal power production, which is necessary to encourage the establishment of a service industry capable of supporting rapid growth in power output. It is therefore hoped that geothermal developers ignore those who promote restrictive approaches to managing technical knowledge not directly related to exploration activities (which should be closely guarded) and embrace an open-source paradigm consistent with the reality that for geothermal to scale quickly and economically, it must become one of the lowest cost, most reliable forms of power generation, which is, as the U.S. unconventional industry has demonstrated, a result best achieved by adopting an open-source ethos.

1. INTRODUCTION

The amount of geothermal energy contained in the Earth's crust that is potentially recoverable is immense, being sufficient to supply all of mankind's primary energy needs for thousands of years (Tester et al., 2006). However, other than in a few countries such as Iceland and New Zealand, geothermal power output today comprises only a tiny fraction of the overall power supply, with for example, geothermal's share of the U.S. power market being less than half of one percent (Figure 1). This disconnect between the size of our planet's geothermal energy resources and geothermal's power market share is primarily due to subsurface-related technological challenges that have historically made finding, appraising, and developing geothermal fields too costly and/or too risky to attract substantial investment.

Fortunately, the outlook for being able to deliver acceptable full-cycle economic outcomes has improved considerably over the past decade. This has been due to: 1) a plethora of improvements made by long-time geothermal industry participants, such as advancements in understanding the geologic characteristics of areas of significantly elevated heat flow (Faulds at al., 2015) and advances in geothermal-focused AI / machine learning applications (Grujic et al., 2025), 2) the adoption of oil and gas technologies and best practices, and 3) hyperscalers being willing to pay a premium for clean, firm power. As a result, there is a growing belief that a dramatic ramp up in geothermal power production will be achieved, not only from enhanced geothermal systems (EGS), which have received the lion's share of attention and funding over the past few years, but also from hydrothermal systems, especially those that have no surface expression (i.e., blind systems), as well as sedimentary geothermal systems and pressure geothermal projects.

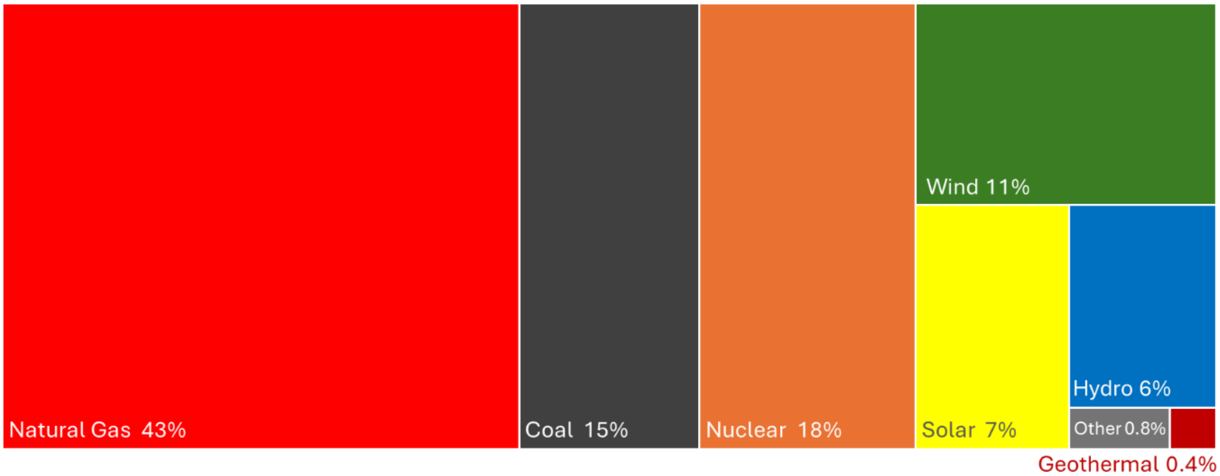

Figure 1: Graph showing the sources of power generated in the U.S. in 2024. Whilst the U.S. geothermal industry aspires to quickly grow power output, because geothermal's current share of power production is only about 0.4% (see bottom right corner of the diagram), other sources of power, especially natural gas, can offer greater surety of delivering electrons when and where they are needed and can access capital at a lower cost. Data taken from the U.S. Energy Information Administration (2025a).

Given this growing enthusiasm for geothermal power production and the enormous size of the economic prize that could be captured if the industry could dramatically lower development costs and increase per well heat recovery, it seems timely to consider what lessons can be learned from other resource extraction industries that had to overcome significant subsurface-related technical challenges and have since gone on to achieve rapid production growth, with the next section of this paper being devoted to this topic.

2. RAPIDLY SCALING TECHNICALLY CHALLENGING RESOURCES – LESSONS LEARNED FROM OIL AND GAS

Since the mid-twentieth century, the oil and gas industry has provided most of the energy consumed by humankind. In doing so, the industry has depleted much of our planet's endowment of easily extractable hydrocarbons, forcing oil and gas operators to find ways to economically develop increasingly challenging oil and gas deposits (Figure 2). Lessons learned from scaling up two types of economically challenged hydrocarbons, Canadian oil sands and U.S. unconventional reservoirs, provide particularly valuable insights for accelerating growth of geothermal power output, with both having gone from being negligible sources of production to major contributors in time frames comparable to that which the U.S. government aspires to see for geothermal power production (Figure 3).

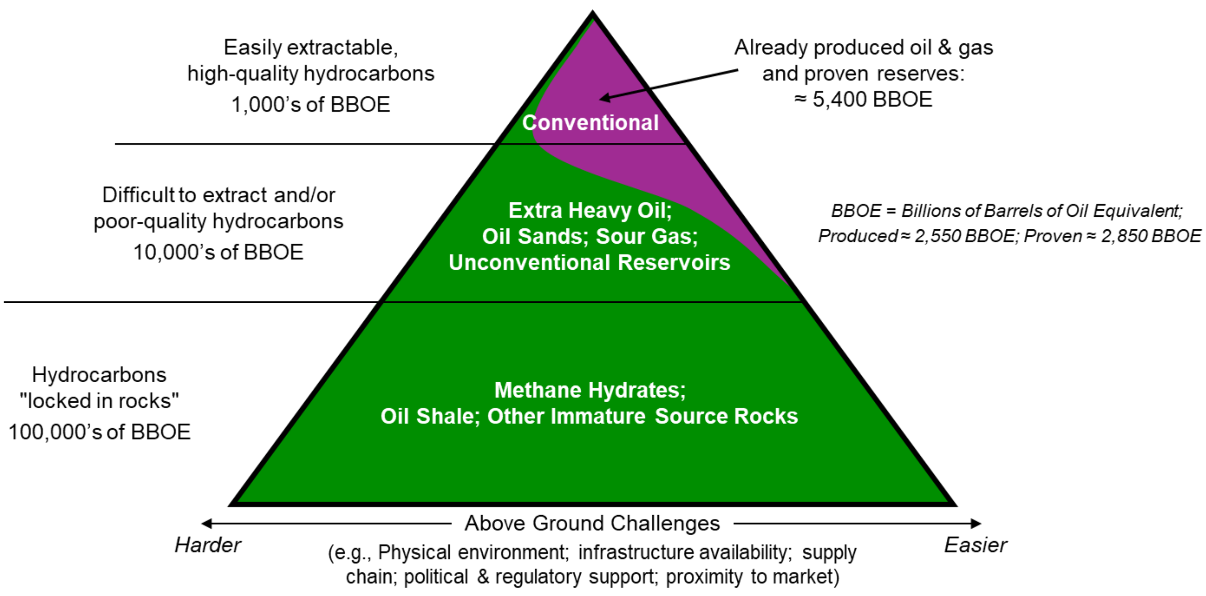

Figure 2: A modified version of the classic oil and gas resource pyramid diagram showing how both reservoir properties and above ground challenges impact the pace at which development takes place. Development tends to proceed from the top right side of the resource pyramid towards the bottom left, with difficult to extract hydrocarbons being first produced in areas with the fewest above ground challenges (e.g., unconventional reservoirs were first commercialized at scale in Texas). Please note that the hydrocarbon volumes shown on the diagram have been estimated by the author from numerous sources, most especially Energy Institute (2025), U.S. Energy Information Administration (2025b, 2025c), and Pratt (1952).

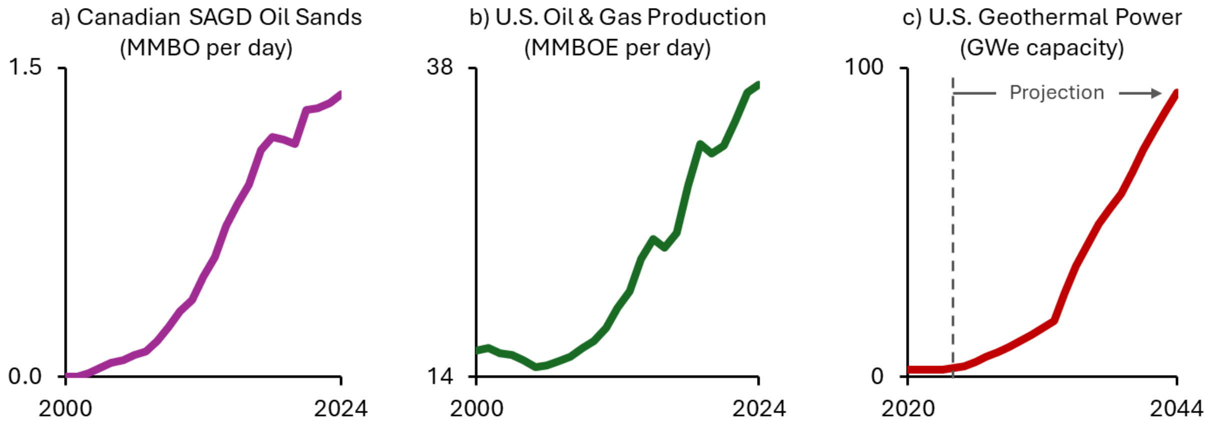

Figure 3: Plots showing a) Canadian oil sands production from wells using Steam Assisted Gravity Drainage (SAGD) technology, b) total U.S. hydrocarbon production, and c) the U.S. government's aspirations for growth in geothermal power production capacity. While the three plots have different vertical scales, all three exhibit rapid growth in output or capacity over a 25 year period, with a) SAGD oil production having grown from a negligible volume at the turn of the century to a point where it today delivers approximately a quarter of Canada's hydrocarbon liquids output, b) U.S. production having increased by over 150% since 2005 as a result of operators having learned how to use hydraulically fractured horizontal wells to unlock previously uneconomic oil and gas resources, and c) the geothermal power production growth curve that the U.S. government is working with industry to try to achieve. Data shown in these graphs were obtained from: a) Alberta Energy Regulator (2025), b) Energy Institute (2025) and U.S. Energy Information Administration (2025d), and c) U.S. Department of Energy (2024).

2.1 Lessons Learned from the Scale Up of Steam Assisted Gravity Drainage (SAGD) Oil Sands Production

Turning first to potentially transferable lessons from the history of oil sands production using SAGD technology, actions taken by various parties that accelerated the creation and sharing of technical knowledge necessary to unlock the economic potential of this staggeringly large resource included:

- The Alberta government played a formative role in establishing the technical viability of the SAGD oil recovery method by constructing at its sole expense an Underground Test Facility (UTF) at which it demonstrated the successful operation of the first ever horizontal SAGD well pair in 1987 (Smejkal et al. 2025; Alberta Government, 2026). This was a strikingly similar role to that played by the U.S. Government at the Utah FORGE test site, which established the viability of using high-angle wells for EGS production.
- Upon conclusion of the initial SAGD test wells, ten oil companies each paid $16 MM (CAN) to join the UTF project. This equalized government and industry funding and allowed for the drilling of additional wells and the performance of further technology demonstration projects, the end result of which was that UTF researchers determined that instead of being able to realize a 30% to 45% bitumen recovery using SAGD techniques as had been expected, recoveries of 65% were achievable (Alberta Government, 2026).
- An undoubtedly important but apparently uncommented upon aspect of having government and industry petrotechnical subject matter experts actively participating in the UTF project was that it promoted the establishment of inter-organizational relationships and the sharing of data and ideas, as evidenced by the fact that nearly 850 technical publications and project reports were directly generated as a result of the Alberta Government's efforts to spur oil sands related innovation (Hein, 2016).
- By the start of the twenty-first century, the basic SAGD technologies required to unlock in-situ oil sands production were well established and industry took the lead from that point forward in ramping up production and continuing to drive further innovations, with connections forged during the UTF project between subject matter experts that by the year 2000 were scattered across industry, universities, and government organizations being instrumental for accelerating progress.
- Also important was the fact that several of the SAGD developments involved Joint Ventures (JVs) between two or more oil companies. For example, Cenovus and ConocoPhillips were in a JV to develop the Christina Lake and Foster Creek Fields (with Cenovus being the operator), and ConocoPhillips and Total likewise were joint owners of the Surmont Oil Sands project (which is operated by ConocoPhillips). This arrangement of joint ownerships was valuable because it allowed technical knowledge to migrate from one project to another quickly, thereby accelerating the overall pace of oil sands production growth.

Insights applicable for accelerating the growth of geothermal power output that can be garnered from the Canadian SAGD journey from being a nascent, uneconomic concept to becoming one of the largest sources of Canadian oil production include:

- It was enormously helpful to have government financial support for technological risk taking,
- The role the Alberta government played in bringing together ten of the largest oil operators in Canada to jointly develop the suite of technologies required to make SAGD commercially viable was arguably as important as providing funding,
- The sharing of data, knowledge, and patents amongst the participating companies significantly accelerated production growth, and
- Relationships established during the UTF project resulted in continued knowledge sharing between industry participants, government researchers, and university staff long after the project ended.

It is also worth noting the important role the UTF project played in being a site at which technologies could be tested in the field at relatively low incremental costs since being able to quickly test new technologies and approaches for extracting hydrocarbons at low costs is a theme that also underpinned U.S. unconventional output growth.

2.2 Lessons Learned from the Scale Up of U.S. Unconventional Reservoir Production

As shown in Figure 4, it is herein suggested that, at a high level, the history of unconventional reservoir technical knowledge creation and disbursement is a story best told in three parts, with:

1) An initial period during which government support for the development of innovative methods of extracting natural gas from tight formations coupled with private sector investment from a modest number of innovative oil and gas companies led to technical breakthroughs that enabled economic extraction of hydrocarbons from unconventional reservoirs to be achieved,
2) A second period during which operating companies used what with hindsight was a largely immature, relatively high-cost approach for extracting oil and gas from unconventional reservoirs to rapidly grow production through the brute force deployment of literally thousands of rigs drilling relatively short understimulated horizontal wells during a time of high oil and gas prices, with essentially all forms of new knowledge being closely guarded, and
3) A third period triggered by the late-2014 OPEC-engineered collapse in oil prices, which caused unconventional reservoir operators to have to massively innovate to drive down development costs and increase per well production rates, leading to a significant uptick in the sharing of both development-related technical knowledge and the cost of technology demonstration projects.

Figure 4: Graphic showing the three phases of unconventional reservoir knowledge creation and sharing that have been prevalent over the past half-century. While holding knowledge useful for developing and maintaining an advantage in acquiring the best acreage made perfect sense during the second phase, history would show that because unconventionals made up only a tiny share of global oil and gas production and had thin profit margins, unconventional producers would have benefitted enormously from sharing development and operational focused knowledge sooner.

The creation and disbursement of technical knowledge during the first of the three above noted periods was enabled to a large degree by the deployment of government incentives that became available starting in 1976 when the U.S. Government funded the Gas Research Institute (GRI) through a surcharge on interstate gas sales and initiated the Eastern Gas Shales and Western Gas Sands R&D Programs (U.S. Department of Energy, 2007).

Under the auspices of these three entities, hundreds of millions of dollars of research was carried out, including numerous field tests operated by private companies, with for example Mitchell Energy executing a DOE funded recompletion project in Devonian Shales in the Appalachian region in the early 1980s and also participating with GRI/DOE in the drilling of a commercially unsuccessful horizontal test well in the Barnett Shale in the Fort Worth Basin in 1991 (Steward, 2013).

When coupled with an even larger amount of private investment, this effort ultimately resulted in Mitchell Energy demonstrating the economic viability of extracting gas from the Barnett Shale, which was an event that symbolically closed out the first period of the unconventional story – a period that lasted for approximately 25 years.

Following on from Mitchell Energy's Barnett Shale breakthrough, which occurred at a time when natural gas prices were rising rapidly, increasing from less than $2 per mcf throughout most of the 1990s to over $5 in 2001 (U.S. Energy Information Administration, 2025e), there was a rush to acquire prospective acreage. This resulted in much of the technical focus being placed on perfecting techniques for identifying new unconventional reservoir plays and the best landing zones within a targeted formation, both of which were activities companies cloaked in secrecy to avoid revealing anything that might allow a competitor to beat them at securing prime leases.

This is not to say that technical knowledge useful for reducing well cost and increasing per well production rates and recovery factors was not being shared during the 2000s because it was. For example, service companies were peddling their knowledge about the drilling and completion practices that successful operators were using and E&P companies unfamiliar with unconventional reservoirs were educating themselves by visiting the data rooms of established unconventional producers that were trying to sell or promote their acreage positions. However, sharing technical knowledge in an open-source manner was not the norm during this period, with most companies having implemented restrictions as to what information could be communicated externally.

This made sense from one perspective given the emphasis operators were placing on adding acreage and testing new plays. Unfortunately, the "do not share mantra" was nearly universally applied and was suboptimal for solving the numerous development-related technical challenges that the industry would have to rally together to jointly solve after the late 2014 OPEC-engineered oil price collapse. Challenges such as determining how to minimize parent-child production degradation, avoid casing deformation in plays containing critically stressed faults, and manage excessive produced water.

Nonetheless, with prices being high, companies were able to take what might be characterized as a "brute force" approach to increasing oil and gas output by adding an ever-larger numbers of rigs to their drilling fleets. This resulted in the total U.S. rig count rising rapidly from a low point of less than five hundred in 1999 to over two thousand in 2012 (with a few notable short duration swings downwards interrupting this trend, such as during the 2008-09 global financial crisis).

By adding ever more rigs and investing ever more capital, unconventional reservoir operators increased U.S. hydrocarbon production significantly, from a low point of around 14.5 million barrels of oil equivalent per day in 2005 to nearly 25 million in late 2014.

Unfortunately, this period of being able to count on high prices to deliver acceptable returns on investment ended abruptly when OPEC decided that U.S. unconventional oil producers had stolen too much market share from them, with OPEC having by mid-year 2014 shut in several million barrels per day of productive capacity to keep oil prices propped up.

Once OPEC decided to return the shut-in capacity to the market, prices fell precipitously, reaching a low point of less than $30 per barrel in early 2016. This was a price at which U.S. producers' profitability disappeared, resulting in a near death experience for the industry. This experience was however not all bad in that it set in motion a wave of innovation and knowledge sharing that allowed U.S. production to come roaring back even stronger than before as most producers moved away from pursuing a hyper-active growth strategy to one focused on achieving dramatic performance improvements – improvements that would allow them to achieve an acceptable rate of return on development capital investments at much lower product prices.

As is shown in Figure 5, this switch in strategy not only paid near immediate dividends but continued to improve performance year after year, with industry benchmarking indicating that in 2024, the average U.S. unconventional reservoir rig drills about twice the lateral length for half the cost and in half the time compared to 2014, resulting in considerably improved economic performance.

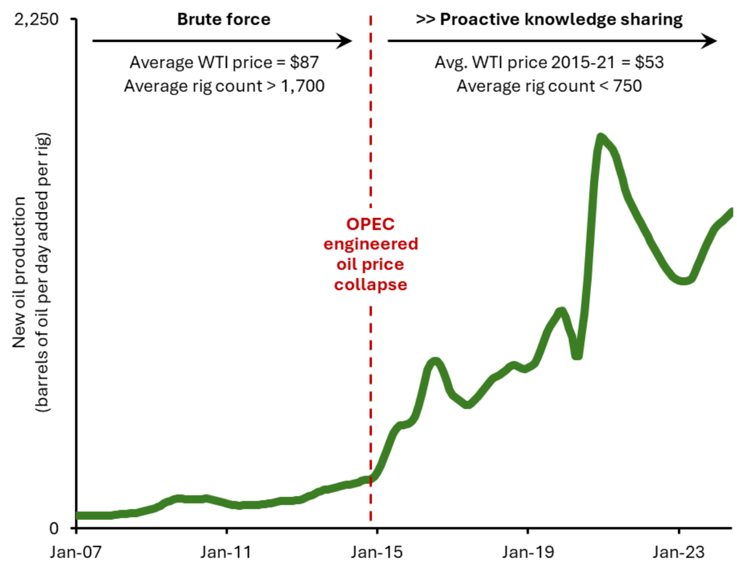

Figure 5: Graph showing new oil production added per rig per month in the Permian Basin between 2007 and 2024. While this metric isn't commonly utilized within the oil and gas industry, it is an extremely useful one since changes in both the production rate achieved in new wells and the length of time (and therefore costs) required to drill wells are accounted for in the calculation. As shown in the graph, while the output per rig more than doubled between 2007 and late 2014 when oil prices were high, it was not until after the late 2014 oil price collapse that output really took off. With hindsight, this seemingly proves the adage that good can be the enemy of great since operators were able to achieve acceptable levels of profitability when prices were high by relying on in-house innovation and limited amounts of indirect technical knowledge sharing, whereas after the price collapse, they had to up their game in both areas. Interestingly, the spike in per rig output in 2020 resulted from another industry near death experience, this one related to the COVID 19 pandemic, with all but the rigs in the best performing parts of the Permian Basin being laid down because of the dramatic pandemic-related fall in oil and gas demand and prices. WTI = West Texas Intermediate crude oil. Data from U.S. Energy Information Administration (2024), Baker Hughes (2025), and Energy Institute (2025).

As far as the lessons learned from the U.S. unconventional industry's near-death experience associated with the 2014 oil price collapse that seem useful for geothermal developers to be aware of, there are several, including but not limited to:

- U.S. oil and gas operators learned they were "small fish in a very large pond" (i.e., they produced < 10% of global hydrocarbon output),
- They also learned that they were relatively high-cost producers whose profit margins would disappear if countries like Saudi Arabia and the United Arab Emirates, which had top-quartile profit margins, decided to win back market share by increasing output, and
- Perhaps most importantly, they learned that while it made sense to jealously guard technical knowledge useful for securing the best acreage in the best unconventional reservoir plays, there was much to be gained from sharing technical knowledge helpful for determining more efficient ways to extract hydrocarbons from these same reservoirs once prospective acreage in a play had been all leased up.

Regarding the last point, it could be argued that it was extremely unfortunate that it took a near death experience for the unconventional reservoir portion of the oil and gas industry to switch from a "grow through deploying numerous rigs paradigm" to a strategy focused on making dramatic performance improvements through innovation and the sharing of development-related technical knowledge since if the industry had made the switch sooner, it could have realized tens of billions of dollars of additional profits.

2.3 Why it Made Sense for Oil and Gas Operators to Take an Open-Source Approach to Sharing Technical Knowledge

As to reasons why oil and gas companies elected to take a more open-source approach to sharing development related technical knowledge after the 2014 oil price collapse, the most compelling one was the recognition that no company possessed enough innovative ideas to quickly return development capital investments to acceptable levels of profitability at much lower product prices.

This was due to both the unique and then poorly understood geologic characteristics of unconventional reservoirs and the industry having limited prior experience with the well construction techniques being utilized, especially regarding experience with deploying multi-stage, limited-entry, plug-n-perf completions in horizontal wells.

By way of providing an example of how learning from each other helped companies make progress, ConocoPhillips, whilst being amongst the leaders in determining optimal well spacing and stacking geometries in the Eagle Ford as a result of being an innovator in the use of geochemical fingerprinting and other technologies, was a laggard in switching to lower cost proppant types. This delay occurred because lab tests that the company performed suggested proppant crushing would impair production, which caused the company to test the use of more expensive man-made ceramic proppants whereas other companies elected to experiment with the use of locally derived sands – sands that were poorly sorted and had low crush strength, but which ultimately turned out to be the better economic solution.

Luckily, by learning from each other by various means, U.S. unconventional developers were able to substantially cut the oil price needed to achieve acceptable rates of return by both reducing costs and increasing per well output, with the uplift in value resulting from the relatively free flow of technical knowledge between oil and gas operators being depicted schematically in Figure 6.

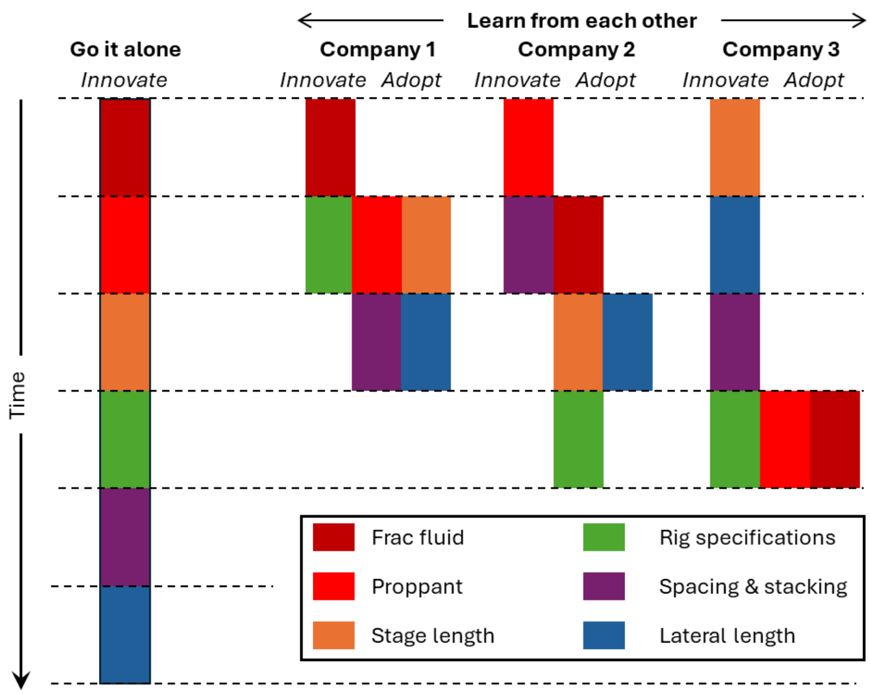

Figure 6: Diagrammatic depiction of how companies that operate in an open-source ecosystem wherein they can learn not only from their own innovations but can also adopt technologies that other companies successfully demonstrate will improve faster than companies that must rely entirely on innovations they develop internally. While this example idealizes the effectiveness of learning from others, the degree to which this occurred after the 2014 OPEC-engineered oil price collapse should not be underestimated, for this type of learning largely explains how unconventional focused oil and gas companies were able to not only survive OPEC's attempt to crush them but emerge after a relatively short period of time even stronger and more efficient.

Examples demonstrating the change in mindset that occurred at many oil and gas operators around the usefulness of sharing technical knowledge that could help optimize the development of unconventional reservoirs from when the initial land rush was occurring up until the OPEC-engineered collapse of oil prices and then afterwards include but are not limited to:

- ExxonMobil's conversion from holding information extraordinarily tight when the company first took a large position in U.S. unconventional reservoir plays in 2010 to becoming one of the more proactive sharers of technical knowledge, having for example: 1) published the results of an important hydraulic fracturing instrumented well experiment they performed at their sole expense in the Permian Basin (Benish et al., 2024), 2) become one of the more prolific presenters of papers at the Unconventional Reservoir Technology Conference (URTeC), and 3) hosted ResFrac's 2025 Annual Technical Symposium at their global headquarters, which was attended by over 100 hydraulic fracturing subject matter experts from numerous oil & gas and geothermal companies, several of whom, including some of ExxonMobil's participants, presented papers describing novel methods by which ResFrac's fully coupled hydraulic fracturing and reservoir simulator could be used to optimize unconventional reservoir completions.

- Pioneer Natural Resources leading the way as far as the number of technical papers submitted in the early years of URTeC, which was convened by the three largest subsurface-focused oil and gas professional societies – AAPG, SPE and SEG – for the first time in August 2013.
- ConocoPhillips sharing the results of a large-scale hydraulic fracturing pilot the company executed at their sole expense in the Eagle Ford Formation that provided invaluable insights into: 1) the nature of fractures emanating from horizontal wells, 2) the distribution of proppant within the system of hydraulically created fractures, and 3) differences in drainage around propped and unpropped fractures (see Figure 7).
- Devon disclosing results of a comprehensive study of redevelopment, infill and refrac opportunities in the Eagle Ford (Karacaer et al., 2021)
- Hess publishing the results of a Bakken pilot focused on measuring far field drainage on a pad containing six 10,000' long laterals with a dedicated observation lateral located in the Three Forks Formation that was instrumented with cemented pressure gauges and fiber optics along the entire lateral length (Cipolla et al., 2022).
- URTeC's Executive Advisory Board, which in the late 2010s was comprised of Chief Technology Officers or very senior technology leaders from BP, Chevron, Concho, ConocoPhillips, Devon, Hess, Pioneer, Saudi Aramco, and Shell, energetically pushing for: 1) operators publishing the results of impactful in-house technical studies, 2) standardization of approaches for the sharing of technical data, and 3) cost sharing on technology demonstration projects.

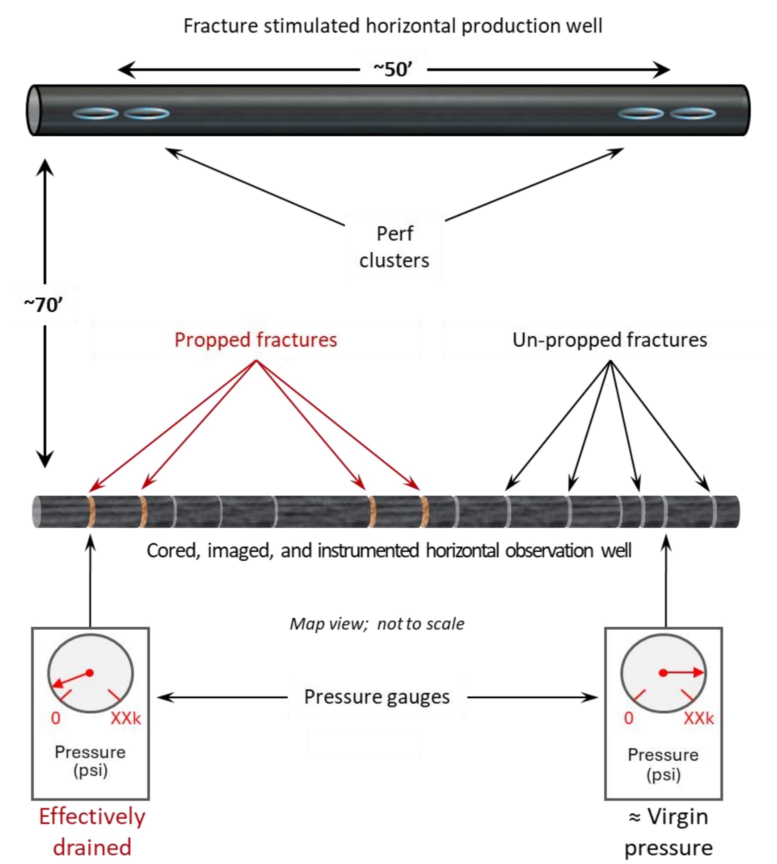

Figure 7: Simplistic diagram depicting some of the important learnings from ConocoPhillips' Eagle Ford hydraulic fracturing characterization pilot, which consisted of a vertical monitoring well and four horizontal laterals drilled through a system of previously created hydraulic fractures emanating from a horizontal producer. Insights garnered from the pilot that helped optimize Eagle Ford development activity included: 1) hydraulic stimulation does not create single fracture planes emanating from each perf cluster, but rather swarms of sub-parallel fractures, with the number of fractures exceeding the number of perf clusters by at least two orders of magnitude, 2) very few of the hydraulically created fractures are propped, with the distribution of propped fractures not conforming to the perf cluster spacing, 3) very little proppant was transported beyond one hundred feet from the production well (at the locations penetrated by the four horizontal laterals), and 4) pressure gauges indicated that while considerable drawdown occurred in the vicinity of propped fractures, little to no recovery was occurring around unpropped fractures (Raterman et al. 2017 and 2019).

2.4 The Importance of Hydraulic Fracturing Test Sites (HFTS)

While many of the above noted technical knowledge sharing examples consisted of publication of results generated by a single operator or an operator working with one or more service companies, a notable exception to this approach was when the Gas Technology Institute (which was renamed GTI Energy in 2021) brought together industry, government, and academic organizations between 2014 and 2023 to construct and operate two large-scale Hydraulic Fracturing Test Sites (HFTS) in the Permian Basin.

Unique aspects of these projects that helped make them extremely successful included:

- Each project (i.e., HFTS 1 and HFTS 2) was located on leases held by an oil and gas operator who took responsibility for executing the project and donated a considerable amount of offset data and reports that allowed all participants to develop a solid understanding of the geology of the test site,
- Participating companies had the opportunity to influence the planned scopes of work by assigning subject matter experts to serve on technical advisory subcommittees,
- Cost for the projects were shared approximately equally between the industry participants and the U.S. government, except that the operators on whose leases the two test sites were built did not have to pay any of the capital costs (i.e., for HFTS 1, the operator was Laredo Energy; for HFTS 2, it was originally Anadarko but became OXY after Anadarko was acquired in 2019),
- Data generated by the projects were shared with the project participants as soon as practical after being acquired and in many cases, were jointly interpreted by the technical advisory subcommittees,
- Public release of data was quarantined for two years, after which time data were made available to all interested parties, and
- After the two-year waiting period, numerous technical papers and presentations were generated by GTI and project participants.

Both projects provided insights helpful for optimizing development of Permian Basin unconventional reservoirs, with some insights being applicable beyond the basin. Particularly noteworthy insights included: 1) confirmation of the intense plane-parallel fracturing patterns first seen in ConocoPhillips' Eagle Ford hydraulic fracturing pilot project, 2) demonstration of how depletion from adjacent parent wells could radically modify the dimension of fracturing in child wells, and 3) verification of the effectiveness of new diagnostic technologies, including but not limited to several advancements in fiber optic measurements such as high resolution strain using the Rayleigh frequency band and deployment of tools capable of imaging perf erosion and casing deformation (Ciezobka, 2022 and 2023).

While both test sites generated useful data, perhaps more importantly, they brought together many of the largest U.S. unconventional reservoir development companies to work cooperatively to find ways to improve performance (see Figure 8 below for the location of the projects and a list of project participants).

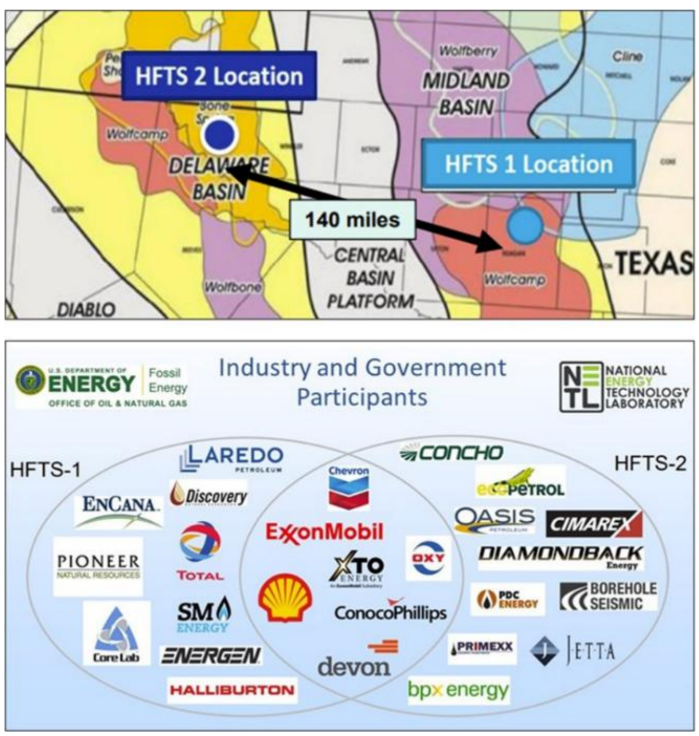

Figure 8: Participants in the HFTS 1 and HFTS 2 projects included several of the leading unconventional reservoir operators and service companies, as well as national laboratories and university researchers. Many of the operators and service companies devoted subject matter experts to help with planning, data gathering, interpretation, and/or integration of technical insights. The two elements comprising this figure were taken from (Ciezobka, 2022).

Particularly noteworthy in this regard was the quality of Subject matter experts that not only the operators of the two test sites committed to this effort, but also many of the non-operating participating companies did as well, with some of the more noteworthy participants from non-operating companies including Kyle Haustveit from Devon Energy (who is currently the Assistant Secretary for the U.S. Department of Energy's Hydrocarbons and Geothermal Energy Office), and Kevin Raterman, Ge Jin and Dana Jurick from ConocoPhillips and Gustavo Ugueto, Alexei Savitski and Paul Huckabee from Shell Exploration & Production Company, all of whom have distinguished themselves by publishing important technical papers and/or their contributions to professional technical societies.

The dedication of staff of this caliber indicates the importance participating companies placed on maximizing the value of these projects, but perhaps even more importantly, dedication of staff was instrumental towards creating trusting relationships between the participating companies' technology organizations – relationships that led to additional collaborative efforts and inter-company communication of technical knowledge.

2.5 Additional Insights Related to Open-Source Unconventional Reservoir Knowledge Sharing

One additional learning from the U.S. oil and gas industry that could be useful for scaling geothermal power production is that it usually makes little sense for an operating company to retain in-house technologies that would lend themselves to being offloaded to service companies better positioned to drive down per unit costs and improve performance by making the technology readily available across the entire industry.

A good example of the application of this logic from the unconventional reservoir space would be Devon's decision to spin-out the Sealed Wellbore Pressure Monitoring technology it had developed in-house even though some might have argued that it provided a potential competitive advantage by allowing Devon alone to have the ability to simply and cost effectively characterize hydraulic fractures. While keeping this type of technology in-house strikes many as the obvious choice, it seldom leads to significant value creation, only extra costs and poorer performance compared to what a service company could deliver.

2.6 Open-Source Unconventional Reservoir Knowledge Sharing – The Bottomline

Wrapping up this section of the paper, Figure 9 shows how the U.S. unconventional reservoir industry was able to sustain a rapid pace of production growth even after the 2014 OPEC-engineered oil price collapse. The industry was able to achieve this result because it increased its focus on innovations useful for dramatically reducing well costs and increasing per well production rates. Notably, the conversion from a closed-source to an open-source approach for sharing development and operations related knowledge was a substantial reason why the industry was able to avoid the death blow OPEC intended to deliver and go on to achieve superior profitability compared to when oil prices were approximately twice as high. While this can be seen as a success story, with hindsight, it would have clearly been better to have changed the approach to knowledge sharing before OPEC forced the conversion, with the geothermal power industry being today in position to do what the U.S. unconventional reservoir industry failed to do at a similar point in its evolution, as is discussed in the next section of this paper.

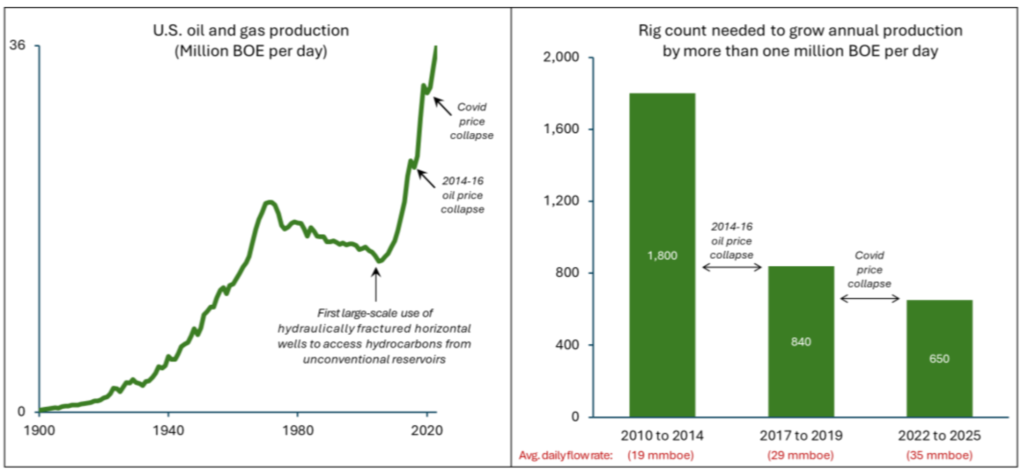

Figure 9: The graph on the left shows U.S. hydrocarbon production from the start of the 20th century through to the present. The graph on the right, the number of rigs required to grow production by over one million barrels of oil equivalent per day between 2010 to 2025. The ability to achieve this high level of production growth with a smaller number of rigs resulted from a plethora of innovations large and small, with some of the bigger drivers including: 1) dramatic increases in horizontal lateral lengths (from 3,000' early on in the Barnett Shale play to over 20,000' today in most basins), 2) optimization of well spacing and stacking geometries and completion designs, and 3) significant improvements in drilling performance. While a number of operators were at the forefront of rapidly driving forward innovation in one or more of these areas after the 2014 price collapse, almost every operator benefitted from learning from other companies' mistakes, difficulties, experiments, and successes. Production data (left) is from Energy Institute (2025) and several other sources. Rig count data (right) is from Baker Hughes (2025).

3. APPLICATION OF LESSONS LEARNED FROM OIL AND GAS TO GEOTHERMAL POWER PRODUCTION

3.1 Why Irrational Exuberance Should Be Avoided Early On After Making a Technology Breakthrough

For the geothermal power generation industry, 2026 will be an exciting year as: 1) developers ramp up drilling activity across all the major categories of subsurface heat extraction technologies, 2) outcomes from recently completed and ongoing technology demonstration projects are reported (e.g., Mazama Energy's Newberry Volcano SHR EGS project and further experiments at the DOE-funded Utah FORGE test site), and 3) Phase One of Fervo Energy's 500 MWe Cape Project comes online.

Because of these and other factors, feelings of accomplishment and confidence are permeating the industry, much as was the case in the early days of the ramp up in unconventional reservoir and SAGD oil sands production.

While this is for the most part a positive phenomenon, it would be timely to take a moment to consider lessons learned by the U.S. unconventional reservoir and Canadian SAGD oil sands industries at a similarly early stage of their expansion, lessons such as:

- Whereas U.S. unconventional reservoir producers were like a small fish in a big pond at the time OPEC engineered the late 2014 oil price collapse that was meant to suppress U.S. production growth, geothermal power producers are collectively at best a minnow in a large lake in all but a few countries, with incumbent large power producers (e.g., natural gas, coal, nuclear, wind and solar) being unlikely to want to cede significant amounts of market share to geothermal upstarts without a fight.

- Premium pricing could disappear quickly, as happened essentially overnight for unconventional reservoir and SAGD oil sands producers in both 2014 and 2020, leaving them saddled with too much debt, too little revenue, and too high development costs. While most in the geothermal power industry seem to believe that premium pricing for clean, firm geothermal power is a sure thing going forward, there are several scenarios in which a price collapse like that which occurred for oil in 2014 could befall geothermal power producers. For example, if hyperscalers' profit margins come under intense pressure and they drop or significantly delay their commitments to achieving net zero carbon emissions, switching focus from paying a premium for clean, firm power to being willing to utilize any form of firm power if it can be purchased at a low cost, this would collapse pricing. Or if hyperscalers are forced by political entities to switch their attention to sourcing power from low-cost sources regardless of carbon content to relieve situations where rapid firm power demand growth is driving down grid reliability and increasing household and business electric bills, prices could fall precipitously.

- Waiting to take collective action to lower the product price required to achieve profitability until when a near death moment occurs is a poor strategy, one that could deliver too little of an impact too late to prevent widespread devastation. Rather, companies should from the outset work together to spur innovation that can drive down development costs by pursuing an open-source approach towards sharing technical knowledge and the cost of technology demonstration projects, which as noted in prior sections of this report, was essential for allowing unconventional reservoirs output to grow rapidly even in the face of significant pricing related headwinds.

3.2 Unexpected and Underappreciated Technical Challenges

An additional class of headwinds that geothermal power producers may be largely unprepared for that unconventional reservoir operators had to deal with and overcome is that while there can be tremendous upside from deploying new technologies to unlock a previously uneconomic class of resources, success often comes only after a number of unexpected and/or underappreciated technical challenges crop up and are overcome.

Unconventional reservoir related examples of this phenomenon include but are by no means limited to the following challenges, each of which threatened to destroy the profitability of development projects until companies worked together to overcome them:

- Severe parent-child well production degradation issues wherein pressure depletion surrounding the first hydraulically fractured horizontal well drilled in an area (i.e., a "parent well") diminishes the effectiveness of hydraulic fracturing in wells drilled adjacent to the parent at a later date (i.e., in "child" well locations), thereby causing production rates to be lower than anticipated.
- Catastrophic casing deformation occurring in unconventional reservoir plays that contain critically stressed faults (e.g., the Montney in Canada, Vaca Muerta in Argentina, and shale gas formations in the Sichuan Basin in China), and
- Difficulties related to handling excessive amounts of produced water (i.e., problems such as elevated levels of induced seismicity due to the disposal of large amounts of produced water in injection wells, high water disposal costs, and increases in the number of casing strings required to drill through shallow water disposal zones to reach deeper productive horizons due to water disposal having elevated pore pressures).

While it is not feasible to generate a full list of development related unexpected and/or under-accounted-for challenges that will need to be overcome at this early stage of increased activity across all the technology classes being pursued to extract thermal energy from the Earth's crust for the purpose of generating power, several of the potentially more confounding issues that are coming into focus, include:

- For hydrothermal developments, while there is considerable progress being made towards improving the efficiency of finding permeable pathways into which production wells can be drilled in areas of high heat flow, including encouragingly, pathways related to blind hydrothermal systems, the ability to determine where to best place injection wells so as to provide adequate pressure support without risking premature thermal breakthrough is a less mature technical capability, one that could cause hydrothermal development projects to underperform expectations.

- For EGS projects, as was discussed in depth at last year's Stanford Geothermal Workshop by Leveille and Zoback (2025), finding ways to avoid negative impacts related to fluid injection into pre-existing critically stressed shear zones needs to be an industry-scale research priority so as to avoid issues such as premature thermal breakthrough, elevated levels of induced seismicity, excessive water losses, and casing deformation, all of which are impacts that could significantly degrade economic outcomes.

- For Super Hot Rock (SHR) applications, advancements required, include: 1) development of downhole drilling systems that can operate at ultra-high temperatures and deliver acceptable rates of penetration, 2) identification or creation of well-construction-related materials such as casing, tubing, and cement that can withstand high temperatures and pressures, large temperature variations, and highly corrosive environments, 3) for high-temperature EGS, sourcing equipment and developing methods for creating consistent, highly-conductive fractures over long distances and identifying or manufacturing proppants that can survive in a hostile environment for long periods of time, 4) development of lower-cost alternatives for building power plants that can operate at super-hot temperatures and identification of approaches that significantly reduce capital expenditures, operating costs, and construction timelines, and 5) geophysical and machine learning/AI methods for better characterizing the subsurface (Clean Air Task Force, 2024).

- For sedimentary geothermal projects, a top priority is developing robust methods for identifying areas with sufficient heat and matrix permeability that are free from stratigraphic and structural barriers and baffles that could disrupt fluid flow between injectors and producers.
- For pressure geothermal developments, improving the efficiency of being able to identify drilling targets that can be cost effectively fracture stimulated while not suffering excessive fluid leakoff, loss of elasticity, or additional fracture growth during pressure cycling will be important.

3.3 Recommended Actions

So, what collective actions could be taken to tackle these and other development and operations related challenges? The list is long, including but not being limited to:

- Greater company-to-company, multi-company, and industry-wide sharing of technical data and knowledge as well as the sharing of cost of technology demonstration projects would be at or near the top of the list.
- The construction of a greater number of field test sites should also be a top priority, especially test sites like those administered by GTI in the Permian Basin (i.e., HFTS 1 and HFTS 2) and by the Alberta Government in Canada (e.g., the oil sands underground test facility). Specifically, what is needed are test sites that: 1) involve numerous companies in funding, planning, and executing the project and interpreting the resultant technical data, 2) allow production data to be acquired over long-periods of time (i.e., years not days, weeks or months), and 3) are laser focused on the most economically important challenges since being able to achieve commercially viable levels of production at a low cost is in the final analysis the deliverable necessary to achieve liftoff (Figure 10).

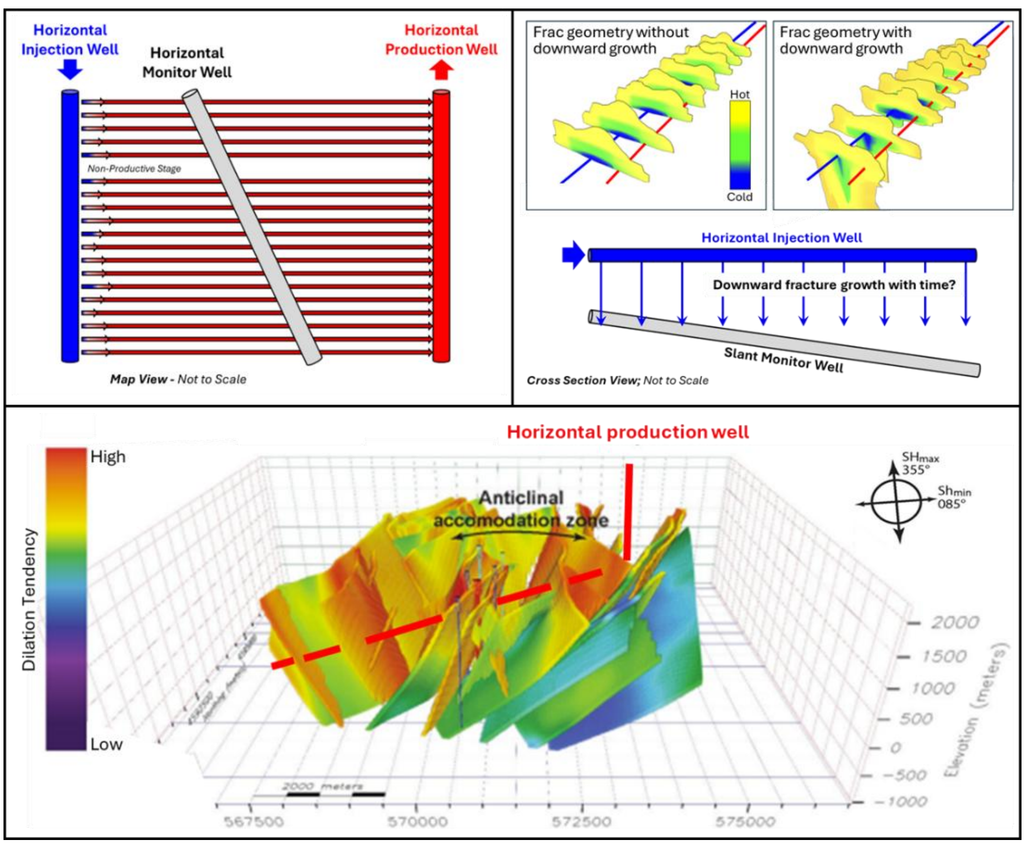

Figure 10: Diagrams showing two aspects of an important EGS technology demonstration project (top) and a valuable hydrothermal demonstration project (bottom). The EGS project would consist of placing monitor wells between a horizontal injector – producer well pair (top left) and below the injector (top right). In these locations the monitor wells would allow characterization of both the fracture system and how the cooling front evolves with time, including whether cooling below the injector causes downward growth of fractures as proposed by McClure (2023). The hydrothermal technology project would consist of drilling a horizontal well through a fault system to demonstrate the ability to connect numerous productive fault strands with one well. Diagrams in top right portion of the display modified after McClure (2023). The bottom diagram modified after Siler et al. (2018).

- The creation of multi-organization technical-problem-solving working groups would also help accelerate innovation and the sharing of technical knowledge, with several of these types of groups having been organized by oil and gas focused professional societies to good effect (e.g., SPE's casing deformation workgroup; see Uribe-Patino et al., 2024).
- Greater recognition that who a company's subject matter experts know is as or more important than their technical know-how in determining the pace of progress, which suggests company executives should robustly encourage internal and external networking, for example by having more of their subject matter experts attend events like the Stanford Geothermal Workshop, which is a forum where participants can increase both their knowledge and the size of their network.
- Industry executives realizing that at the very early stages of trying to achieve liftoff in production from an exceedingly large but technically and economically challenged class of resources, the failure of any company's project will cast a long shadow over the entire industry, making it harder for every company to attract funding and customers, which provides a good reason as to why companies should be helping each other succeed technically rather than seeing themselves purely as competitors (except with regards to acquiring acreage).
- Since supply chain limitations can be a severe drag on progress before and even early on after liftoff is achieved, operators should take actions individually and collectively to help build a stronger supply chain. Examples of how this could be done include: 1) supporting startups that are pursuing innovative solutions to difficult technical challenges (as the oil and gas industry has found several ways to accomplish), and 2) by transferring in-house developed technologies to the service industry without the attachment of overly onerous terms so they can be used by all operators and perfected more quickly as a result of higher levels of usage.

Encouragingly, there are already many actions being taken by organizations, companies and individuals working in the geothermal power production industry that align with the above noted list of beneficial practices, including:

- Utah FORGE has received funding from the U.S. Department of Energy to extend its scope of work.
- Los Alamos National Laboratories has proposed relaunching Fenton Hill as a national demonstration site to validate and scale advanced geothermal systems.
- As a prelude to a U.S. DOE funded SHR demonstration project at the Newberry Volcano in Oregon, Mazama Energy has completed a project whereby they flowed fluid between an EGS injector and producer at the site, with preliminary results having been shared at the 2025 Geothermal Rising Conference and additional information to be shared at the 2026 Stanford Geothermal Workshop.
- The Clean Air Task Force (CATF) has convened a SHR Special Interest Group (SHR SIG) consisting of geothermal and oil & gas operating companies keen to see progress made in being able to operate at ever higher temperatures.
- Several universities have formed multi-client consortiums that are focused on progressing geothermal research or are looking to form such coalitions, with several of these having secured participation from both geothermal and oil & gas companies. This list includes but is not limited to: EGI at the University of Utah, the University of Texas, the Colorado School of Mines, Texas A&M, the University of Oklahoma, and Southern Methodist University. Others such as the University of Nevada at Reno (UNR) have large geothermal research programs that have been long underway through which they coordinate with U.S. Government agencies and other universities to move forward important research (such as UNR's DOE funded Innovative Geothermal Exploration through Novel Investigations of Undiscovered Systems program).
- The DOE's Geothermal Data Repository (GDR) has served as a tool to enable open access to geothermal data for more than 10 years (Weers et al., 2022). Part of the GDR's efforts include outreach, which has successfully fostered a culture of data sharing within the portion of the geothermal community participating in DOE-funded research projects. This has illuminated direct benefits gained from data sharing (Taverna and Leveille, 2025). For example, Fervo utilized FORGE data from the GDR to help site their Cape development project wells (Fercho et al., 2024). And a team of researchers is working on developing machine learning algorithms capable of forecasting induced seismicity using data from publicly accessible induced seismicity catalogs, some of which were obtained from the GDR (Nakata, 2025). In addition, the GDR has recently prioritized efforts to improve reusability of geothermal data through data pipelines and standards (Taverna et al., 2023), which will further enable advancements from shared data. However, to truly jump start progress, data acquired by operators on non-DOE funded projects need to be made more readily available, with oil and gas industry mandatory data disclosure requirements being a good starting point for deciding what data should be disclosed and what can be kept confidential.
- Entities such as the Center for Public Enterprise are forming regional consortiums to try to encourage the sharing of knowledge and best practices and break down barriers that could limit rapid development of geothermal power resources (Arun and Feygin, 2025).

And while there are a plethora of other efforts and initiatives underway to accelerate the creation of additional technical knowledge and share new and existing knowledge broadly across the industry, most of which are unknown to the author of this paper, there is also undoubtedly much more that could be done, with the author's experience from leading ConocoPhillips' U.S. unconventional reservoir exploration program and later its global technology development and adoption efforts suggesting that increasing the level of collaboration on technical topics within the geothermal industry would vastly increase the odds of the industry achieving liftoff.

In the next section of this paper, three additional liftoff-enhancing opportunities unrelated to the oil and gas industry's experience with swiftly growing production from unconventional reservoirs and oil sands are briefly discussed.

4. UNIQUE OPPORTUNITIES TO SCALE GEOTHERMAL POWER PRODUCTION MORE RAPIDLY

4.1 Geothermal Developers Acting as Technology Integrators rather than Technology Specialists

A curious aspect of the current geothermal power production landscape is the near-universal segmentation of geothermal developers into technology-specific categories, namely, hydrothermal operators, EGS developers, sedimentary geothermal systems enterprises, pressure geothermal companies, and closed loop technology advocates. This is surprising when compared to the oil and gas industry where operators tend to be for the most part technology agnostic, deploying fit-for-purpose approaches dependent upon the geologic characteristics of the various hydrocarbon fields they discover (e.g., both ExxonMobil and ConocoPhillips operate oil sands, unconventional reservoir, and conventional fields; Chevron produces heavy oil in Venezuela, sour-gas laden oil in Kazakhstan, and light, sweet oil and natural gas at numerous locations around the planet; and almost every operating company, no matter how small, produces or has the capacity to produce both oil and natural gas).

Not only is developers penchant for specialization curious and surprising, it is more importantly seemingly a sub-optimal economic approach in that for at least four of the five above noted geothermal technology categories (i.e., all but sedimentary geothermal systems), there is a non-trivial probability that a developer searching for a geothermal anomaly with geological conditions favorable for the deployment of the specific technology they are specializing in will encounter conditions better exploited using one of the other technologies, which if not utilized, would result in a less profitable project or perhaps even a foregone development opportunity.

By way of providing examples of potentially poor outcomes that could result from geothermal power development companies narrowly defining their technological boundaries, one could envision:

- A hydrothermal specialist firm failing to find sufficient permeability to support a hydrothermal development project, leading them to walk away from a project that could be profitably developed using an EGS approach.
- An EGS focused company unexpectedly encountering numerous critically-stressed, highly conductive faults within a development area – faults that would significantly complicate the deployment of an EGS style development for the reasons described in Leveille and Zoback (2025), but which would make the area favorable for being profitably developed as a hydrothermal or hybrid hydrothermal-EGS project.
- A hydrothermal firm finding commercially viable levels of permeability and heat within a targeted fault zone but failing to take advantage of the potential to also develop a sizable undeformed area surrounding the fault zone that is sufficiently hot to support an EGS project.
- A pressure geothermal specialist company encountering highly permeable faults in the subsurface – faults that would make deploying a pressure geothermal system impractical for technical reasons, but which could be developed as a hydrothermal power project (i.e., the company discovers a blind hydrothermal system).
- A closed loop technology company encountering and running casing across one or more critically-stressed, highly conductive fault zones that could support an exceedingly profitable hydrothermal development.

It is therefore hoped that geothermal operators that currently limit their focus to a single technological approach will over time develop both the mindset and technical capabilities necessary to allow them to select the appropriate technology or suite of technologies for maximizing the profitability of a project based on the specific geological conditions encountered at a drill site. This will be helpful for more rapidly scaling geothermal power production and would likely encourage a more open-source approach to technical knowledge sharing because developers would see themselves less as technology specialist and more as technology integrators, which is what all the largest, most profitable oil and gas operators have become over the past half-century.

4.2 Modularization of Production Facilities

A second aspect of geothermal power production ostensibly ripe for advancements that could help more quickly scale overall industry output is associated with how heat is converted to power. This is done today almost exclusively using large plants stick-built on site (i.e., plants with ten to multiple tens of MWe of capacity). While there are economies-of-scale advantages to this approach, the disadvantages are numerous as the oil and gas industry learned a long time ago, with some of the larger shortcomings being: 1) sizing of the plant usually occurs before any of the development wells are flowed for a substantial period of time, introducing considerable uncertainty into matching plant size to the amount of thermal energy the planned wellfield will be able to produce, 2) the time line for plant construction is usually much longer than the time required to complete construction of the wellfield, 3) onsite, stick built construction is expensive and increases safety risks compared to work done in factories or permanent fabrication yards, 4) it can be difficult to find qualified workers at remote sites, with the importation of workers from elsewhere for the duration of an onsite construction project being costly and placing significant strain on local communities, and 5) well production rates and the temperature of produced fluids can change over the life of a project in ways that are difficult to anticipate.

For these reasons and likely several others, there would seemingly be benefit associated with switching to an approach for power plant construction that utilizes factory-built, easily transportable modules that would take a fraction of the time to assemble in the field. With such a system, capacity could be added to or subtracted from a development project in increments of modest scale (e.g., a few MWe per module) to better match generation capacity to the amount of thermal energy that a wellfield can deliver. It would also allow equipment to be more easily switched out if after some number of years operating conditions changed significantly.

4.3 Helping the Service Industry Deliver the Technologies needed by Geothermal Power Developers in a Timely Manner

Finally, by way of elucidating an often overlooked benefit of open-source knowledge sharing, while it would not be logical to expect service companies and technology start-ups to openly share the IP behind tools and services they are offering for sale to geothermal developers, there is intrinsic value realized by these companies when geothermal operators publicly share their mistakes, difficulties, experiments, and successes since this allows service companies and tech developers to better understand where to focus resources to align their offerings with developers' needs. In addition, when a success publicized by an operator is related to a new capability developed by a service company or technology start-up, it massively helps accelerate adoption of the service company's invention for reasons described in detail in Geoffrey Moore's classic book about how to accelerate technology adoption – "Crossing the Chasm" (Moore, 1991). Since the development of a large, healthy geothermal power production service industry will be crucial for achieving liftoff in power production, operators should help achieve this outcome by sharing challenges they face and publicizing service companies' contributions to successes they achieve.

5. CONCLUSIONS

At the start of the twenty-first century, the oil sands and unconventional reservoir segments of the oil and gas industry were situated in much the same position as the geothermal power production industry is today, with new technologies capable of extracting hydrocarbons from the Earth's crust at economic rates having been identified but not yet having been deployed at sufficient scale to prove their potential (i.e., SAGD for oil sands; hydraulically fractured horizontal wells for unconventional reservoirs).

Over the next twenty-five years, production from both oil sands and unconventional reservoirs grew rapidly, although both had to deal with significant headwinds related to precipitous drops in product prices as well as the need to find ways to overcome unexpected and previously underappreciated technical challenges.

Looking back with the benefit of hindsight, the importance of industry participants largely adopting an open-source approach to sharing development and operations related technical knowledge is obvious, with it being likely that if this had not happened to the degree that it did, both the pace of production growth and profitability of investments would have been negatively impacted.

Promisingly, many of the open-source approaches to sharing that helped unconventional reservoirs and oil sands achieve liftoff appear likely to be equally effective for accelerating growth in geothermal power production (i.e., develop an industry culture in which companies share knowledge, share technology demonstration project costs, and encourage connectivity between subject matter experts).

Offsetting these causes for optimism is the reality that the management teams of many geothermal power developers are skittish about or downright opposed to sharing technical knowledge with other companies, often as the result of questions from current and potential investors about the depth and breadth of the "moat" protecting their company's intellectual property.

Interestingly, this is little different from the conversations that went on amongst management teams and in board rooms back in the early days of the unconventional reservoir revolution, with what history suggests is that opposition to sharing is in a very limited way exactly the right strategy – the strategy that should be employed when dealing with knowledge related to methods to identify and secure the very best acreage, but when it comes to sharing knowledge that can help reduce development costs and increase per well production, open-source-like approaches beat closed-source approaches hands down.

That unconventional reservoir focused oil and gas companies took too long to recognize this contradiction is obvious when looking at plots like the one shown in Figure 5 since it should not take a near death experience like that which OPEC engineered in 2014 for industry leaders to recognize that once the best acreage has been divvied up, one's true competitors are not those companies that are developing resources similar to those that you are developing but rather the large established entities that your company and companies like yours are attempting to take significant amounts of market share from.

Regrettably, geothermal power producers are today in nearly the same situation as unconventional reservoir producers found themselves in when they began to significantly eat into OPEC's share of the oil market (i.e., they are small fish in a big pond; see Figure 1). This suggests that adopting an approach to knowledge sharing like that which allowed unconventional reservoir developers to not only survive the 2014 price collapse but thrive thereafter would make perfect sense.

As for specific actions that could be taken to improve the pace at which geothermal-related technical knowledge is generated and shared, there are many, with some of the more impactful ones having been described in sections three and four of this paper.

Finally, for anyone who wishes to discuss why geothermal developers should ignore those who promote restricting the sharing of technical knowledge and rather embrace a hyper-open-source paradigm consistent with the evidence presented in this paper that doing so will help geothermal power production scale more quickly and economically than it would otherwise, please do not hesitate to reach out.

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