To: Former Colleagues and Fellow Technology Leaders

From: Greg Leveille

Date: December 15, 2022

Subject: Energy Transitions – Strategies for Selecting Amongst a Plethora of Technology Choices

It was a time of transition within the oil & gas industry. A time when numerous new sources of energy were being vigorously pursued. A time when robust funding was available to develop, test, and attempt to perfect disruptive technologies. And a time during which companies that made the "right" choices grew rapidly, whereas those that chose poorly struggled to remain relevant in a world fundamentally changed from that which had existed just a few years prior.

That the energy industry is primed to undergo disruptive change over the next few decades due to the need to cut atmospheric greenhouse gases is a near universally accepted truth, with the level of change likely to occur being perceived as so profound as to have earned this transition, which will be but one of many that has occurred over the past 200 years, the moniker of "*The Energy Transition*".

It therefore would seemingly be useful to look back at the time of transition noted in the first paragraph to determine what lessons can be learned from the past.

So which transition do the opening four sentences of this paper describe? Could it be the transition that occurred during the second half of the 19th century when water-well drilling technologies were applied to produce oil at commercial rates from fields in western Pennsylvania, thereby ushering in "the age of oil"? Or the transition that occurred over a few decades after World War II when the oil industry moved offshore, thereby enabling access to enormous volumes of previously inaccessible hydrocarbons – hydrocarbons that eventually destroyed OPEC's ability to artificially inflate oil prices by shutting in production in the 1970s and early 1980s?

Actually, while both of these transitions enormously changed the industry, the transition noted in the opening paragraph is the one that humankind confronted in the years just after the start of the 21st century when conventional wisdom suggested that global oil production would soon peak, as would natural gas production in North America (which caused numerous LNG import terminals to be built), with the specter of looming hydrocarbon resource scarcity igniting a mad scramble to find new sources of oil and natural gas to offset decline from existing producing regions and satisfy seemingly insatiable growth in demand for hydrocarbon based products, especially from China and other then rapidly developing nations.

Of course, with hindsight, the outcome of this transition is widely known, with surging production from U.S. unconventional reservoirs having: i) changed the conversation about "peak oil" from one centered on supply scarcity to one focused on when peak demand would occur, ii) transformed global energy-related balances of power by diminishing OPEC+ nations' stranglehold over exportable hydrocarbons, and iii) vastly improved America's economic outlook and geopolitical leverage.

What is less widely remembered is that while unconventional reservoirs emerged as the clear winner of the race to fill the gap created by the inability of traditional sources of oil & gas production to continue to supply the world's growing needs, it was not until relatively late in the transition that it became obvious that output from unconventional reservoirs was scalable to a degree that they could not only help fill the gap but actually flood the market, thereby eliminating the need for companies and governments to continue to invest billions of dollars per year to try to commercialize other technologically immature oil & gas production methods that were being pursued.

Therefore, to help refresh memories about this important time in the history of the energy industry when **a profound transition was both required and achieved**, an overview of efforts to commercialize new sources of oil and gas between 2000 and 2015 is provided in the pages that follow.

Lessons learned during this period that can help with formulating strategies for navigating the even larger transition presently underway include, but are not limited to:

- During large-scale, crisis-spurred, technological transitions, numerous potential solutions will be identified, almost all of which will be championed by strong advocates expounding "compelling" investment theses.
- Given human's shortcomings at quantitatively assessing risk and uncertainty, and investors' fear of missing out on breakthroughs during times of transition, many potential solutions will attract funding, with the "winners" of the auction-like process that matches investors with non-in-house-developed solutions being those investors that most-highly value a particular solution.
- Because funding conveys legitimacy, momentum often builds around solutions even before results are obtained that would confirm or refute critical aspects of investment theses.
- Once an investor commits to pursuing a particular solution or suite of solutions, they often stop assessing other opportunities – thereby developing blind spots as to which solution(s) are likely to win the race to solve the crisis that created the need for a transition to occur.
- Because innovation is usually a highly iterative process, one where experimental results often redirect efforts towards new, more promising pathways, opportunities for which results can be obtained quickly and at low cost will be advantaged over ones where experimentation is slow and costly.
- Cost to experiment, speed of experimentation, the number of players pursuing an opportunity, and the degree of collaboration between players are therefore crucial innovation success factors – factors that should be given far more weight than they traditionally are in making and updating technology development investment choices.

It is hoped that the paper that follows may be helpful to all who are making investments to help navigate the energy transition that lies ahead. As famously said, failure is not an option.

Greg

The Early 21st Century Oil and Natural Gas Energy Transition

The Existential Crisis that Created the Need for a Transition

For most of the 20th century, hydrocarbons were cheap to produce and consume, enormously abundant, and especially for oil, easy to store and transport.

Cheap, reliable, and abundant – a winning combination when it comes to energy. A combination upon which the modern, energy-intensive world was built. A combination that when threatened during the 20th century by human-driven forces such as cartels (e.g., Standard Oil and OPEC) or wars (e.g., World Wars I and II) created economic and geopolitical shockwaves of such intensity as to cause Daniel Yergin to describe oil as "*The Prize*"[1].

It is therefore not surprising that there was an enormous sense of crisis at the start of the 21st century when, unlike with prior supply related disruptions that were caused by human-induced factors, factors that could at least theoretically be reversed fairly quickly if cartels could be broken or wars won, this time, it was nearly universally believed that **the world was running out of oil**, with exploration success for conventional sources of oil being at all-time lows and trending lower[2], and production from existing onshore and shallow water super-giant oil fields, almost all of which had been discovered prior to 1980, being at plateau or in decline[3].

Adding to this sense of crisis, oil output in the U.S., the world's largest hydrocarbon consuming nation[4], had peaked in the early 1970s and fallen precipitously thereafter (Figure 1), and analysts were predicting that U.S. gas production would not be able to keep up with demand, thereby creating a belief that the country would need to import vast amounts of LNG (Figure 2).

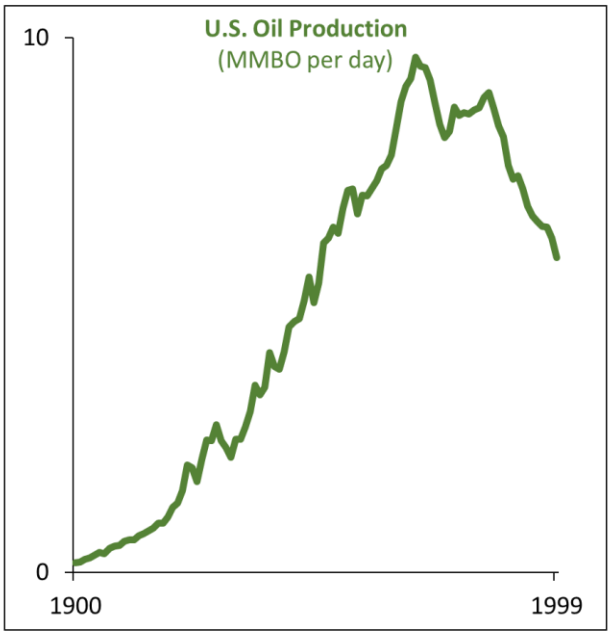

Figure 1. U.S. oil production grew rapidly over the first two-thirds of the 20th century, but peaked in 1970, and fell rapidly thereafter. Data from the U.S. Energy Information Administration's (EIA) website.

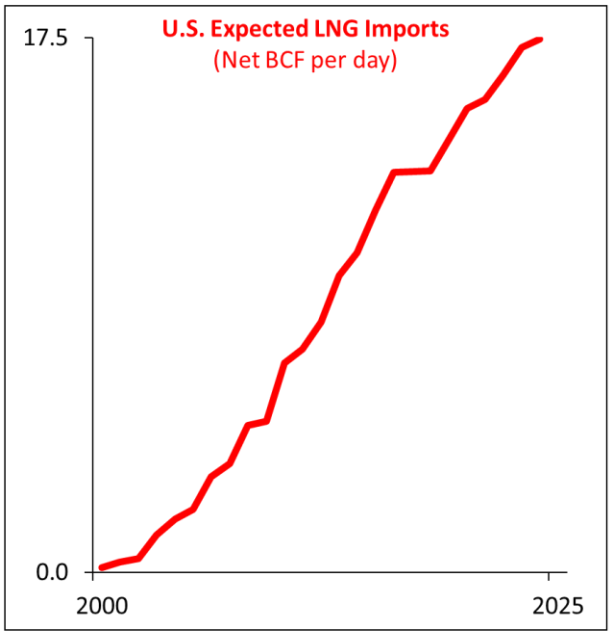

Figure 2. At the start of the 21st century, U.S. LNG imports were expected to grow from near zero to a level that would have made the U.S. the world's largest LNG importing country. Data from U.S. EIA 2005 Annual Energy Outlook.

It is therefore not hard to see why leaders of hydrocarbon importing nations and the oil & gas industry foresaw the need for a transition, either to other forms of energy (which is why America rapidly scaled up its use of biofuels shortly after the start of the 21st century[5]) or to other not-yet-commercial sources of oil and natural gas.

The Oil & Gas Industry's Response

The oil & gas industry's response to this looming crisis was multi-pronged. It included not only efforts to **identify, commercialize, and scale new sources of economically producible hydrocarbons**, which is the topic this paper focuses upon, but also efforts to:

- Apply technology to extend the life of super-giant onshore and shallow water conventional oil fields and onshore heavy oil fields, the majority of which are in politically unstable or unfriendly countries (e.g., Russia, Iran, Venezuela, Libya, Kuwait, Iraq, Nigeria).
- Rapidly scale up capacity to export LNG from "stranded" super-giant gas fields in Qatar and Australia to markets in the U.S., Europe, and east Asia where demand for natural gas either already far exceeded local production or was expected to do so soon.
- Find additional conventional resources in deep water basins around the planet, with deep water at the time being where exploration was focused because onshore and shallow-water targets had been almost entirely picked over during the 20th century.

Interestingly, and to the credit of the oil industry, whereas all three of the bullet-pointed efforts noted above added production that helped fill the expected supply/demand gap, with the benefit of hindsight, it is obvious that they alone would not have been sufficient to close the gap, which is why industry investments to identify, commercialize and scale new sources of economically producible hydrocarbons were so important.

So, what types of new opportunities did industry invest in? As shown in Figure 3, industry pursued a diverse suite of technologies and asset types, some of which represented traditional targets in nearly impossible to operate in environments (e.g., ice-covered arctic seas), others that represented ways to convert super-giant natural gas deposits far from major markets into liquid hydrocarbons, and still others that required finding ways to access hydrocarbons that were literally locked in rocks (e.g., oil shale, gas hydrates, and unconventional reservoirs).

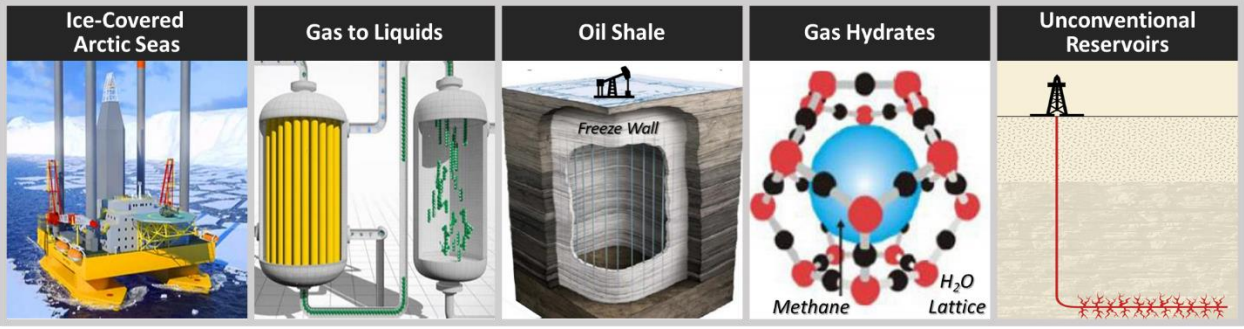

Figure 3. Not-yet-commercial technologies and asset types pursued by the oil industry and governments shortly after the start of the 21st century to enable a transition away from onshore and shallow-water fields – fields that could no longer meet supply needs.

And while with hindsight it is clear that unconventional reservoirs were the best bet by far amongst the many new sources of hydrocarbons available for companies and governments to pursue, this was not at all obvious at the time, as evidenced by the fact that the oil majors (i.e., ExxonMobil, Shell, Chevron, BP, and Total) and most other large international operators initially invested far more time and money pursuing the first four opportunities shown in Figure 3 than they did in unconventional reservoirs, and kept investing in these opportunities for nearly a decade after a breakthrough was achieved in commercializing production from unconventionals, with some of the more audacious, but-ultimately-losing bets including:

- Shell invested over $7 billion pursuing oil prospects in the Chukchi Sea[6], an area where the sea surface is ice covered from November until early summer and the water is shallow enough that grounding of sea ice is a risk that needs to be accounted for when designing facilities and pipelines.
- In addition to Shell, other companies that secured leases and pursued exploration programs in the Chukchi Sea included ConocoPhillips, Statoil, Repsol and ENI.
- BP bid a work commitment of over $1 billion to acquire a **deep-water** license in Canada's Beaufort Sea[7] – a sea that is ice covered during all but a few months each summer.
- Also in the Beaufort, Imperial and ExxonMobil bid a $500 million work commitment to acquire a deep-water license adjacent to BP's, and Chevron secured deep-water acreage by bidding a work program that exceeded $100 million – a work program that Statoil subsequently farmed into[8].
- Keppel, which was at the time was one of the world's largest manufacturers of drilling rigs, teamed up with ConocoPhillips to design a jack-up rig capable of working year-round in harsh, ice-bound, marine environments[9].
- ConocoPhillips also investigated the viability of building floating production systems for use in "iceberg alley" off the west coast of Greenland - systems that could be detached at the seabed and floated away if a collision with an iceberg was imminent, and then moved back on location and reconnected once the danger had passed.
- Shell invested more than $18 billion to bring the Pearl Gas-to-Liquids (GTL) plant onstream at Ras Laffan in 2011. The plant was originally estimated to cost $5 billion, but because of schedule delays and engineering challenges, ended up costing more than three times the original estimate[10, 11,12].
- Both Shell and Chevron were issued R&D licenses in 2006 to pursue in-situ development of oil shale in the Piceance Basin in western Colorado. Shell's process[13], which consumed several hundreds of millions of dollars of funding from the time it was conceived (1980) to when it was shut-down in 2013[14], involved building freeze walls by circulating super-chilled liquid to cool rocks in the subsurface to −60°F (−50°C) to isolate an oil shale "processing area" from surrounding groundwater, after which the oil shale contained within the processing area was heated to over 650°F (340°C) to convert kerogen within the shale to oil, which was then recovered from production wells.

- Chevron's process (codenamed "CRUSH") utilized a different approach that involved fracturing the shales within a confined area and injecting super-heated carbon dioxide to extract oil from the shales[15].
- ExxonMobil, who had attempted to commercialize oil shale via a mining and retort process during the 1970s and early 1980s, but were ultimately unsuccessful, taking a $5 billion write-off at the time, was awarded an in-situ oil shale R&D license in 2010 to test their "Electrofrac" process, which involved injecting an electrically conductive material into induced fractures, forming a distributed heating element that could elevate the temperature of the shale sufficiently that kerogen was transformed into oil[16].
- Total E&P in 2012 entered a joint venture with a technology start-up company (Red Leaf Resources) to pursue oil shale development in Utah. The joint venture was created to prove the commercial scalability of Red Leaf's "EcoShale In-Capsule" process – a process in which oil shale is mined, then placed into large, sealed capsules before undergoing a slow pyrolysis reaction to yield high quality hydrocarbons. Under the terms of the joint venture agreement, Total E&P was to fund an 80 percent share of expenses required to build and operate an early production system, which at the time of the formation of the joint venture, was estimated to cost approximately $200 million[17].
- ConocoPhillips investigated the feasibility of using room and pillar mining techniques to extract oil shale from leases it held in the Piceance Basin in western Colorado and converting it to oil in a retort at the surface. Challenges associated with the project included but were not limited to: 1) the mine would have been one of the largest underground excavations in the world; 2) the retorting process would have required enormous amounts of water to be extracted from the Colorado River – a river whose water is perennially in short supply; and 3) the considerable volume of residue created from the retorting process would have needed to have been transported back underground to be disposed of in the "rooms" created by the mining process.
- Several important tests of technologies designed to extract methane from gas hydrate deposits were performed in the United States between 2000 and 2015[18]. The capital costs associated with these projects were funded by the Department of Energy (DOE), with oil companies providing at their expense the manpower necessary to plan and execute the projects. Tests were executed by BP and ConocoPhillips in Alaska, and Chevron in the deepwater Gulf of Mexico[19]. The ConocoPhillips project[20] was particularly noteworthy since unlike most other experiments that used depressurization to liberate methane from the hydrate lattice, which is an approach that is problematic since depressurization invariably destabilizes the reservoir hosting the gas hydrate deposit, causing all kinds of production problems, ConocoPhillips' project involved injecting CO_2 to replace methane in the hydrate lattice, thereby liberating methane without destabilizing the reservoir while simultaneously sequestering CO_2.
- The Japanese and Chinese governments both executed offshore gas hydrate production tests using depressurization as the method to liberate methane from the hydrate lattice. The Japanese test, which was budgeted at $180 million but likely cost considerably more given the significant amount of drilling and support equipment deployed and the extended duration of the test, took place in deep waters off Japan's east coast[21]. The Chinese test also

took place in deep-water (in the South China Sea off the east coast of the country)[22] and is likely to also have been expensive to execute given operations took place in water depths greater than 3,000'.

Observations, Insights, and Lessons Learned

Given the extraordinary magnitude of the oil industry's investments to identify, commercialize, and scale new sources of economically producible hydrocarbons between 2000 and 2015, it is worth investigating both: i) factors that enabled spectacular success to be achieved in unconventional reservoirs, and ii) why the world's largest oil & gas companies – companies that had access to much of the industry's top talent and enormous amounts of capital – failed in their efforts to perfect technologies to commercialize production from ice-covered portions of the offshore Arctic, oil shale, gas hydrate deposits, and gas-to-liquids conversion.

The observations and insights that follow are based upon: i) the personal experiences of the author while leading ConocoPhillips' U.S. Lower 48 unconventional reservoirs exploration efforts between 2006 and 2009 when the company assembled large acreage positions in the Eagle Ford and Bakken, and leading all or portions of ConocoPhillips' technology programs between 2011 and 2021, ii) knowledge gained from interactions with colleagues in and outside of ConocoPhillips over the past four decades, and iii) extensive reading about innovation related topics.

General innovation-related observations and insights that are important for setting the stage for discussion about efforts by oil companies and governments to identify, commercialize, and scale new sources of economically producible hydrocarbons at the start of the 21st century include:

- Innovation at scale is almost always a highly iterative process – a process that benefits from the incorporation of learnings from both successful and failed "experiments". Because of this, opportunities that can be tested quickly and cheaply, and then tested again and again quickly and cheaply as insights from prior experiments are incorporated, are greatly advantaged over opportunities where experiments are expensive and take a long time to execute.
- Given that no one individual or organization is all knowing when it comes to attempting to identify, commercialize, and scale new technologies, having many "players" with diverse backgrounds pursuing an opportunity increases the probability of success.
- The degree to which learnings are shared between players pursuing an opportunity has a significant impact on the pace of progress and the ultimate chance of success, with "innovation ecosystems" in which there are many players and results are shared openly being strongly advantaged over closed ecosystems with few players.
- People's ability to accurately quantify the probability of success and size of the prize associated with new, technically complex opportunities is poor[23]. Humans also struggle with accurately updating probabilities as new information comes available[24].
- People are better at qualitatively ranking like-kind opportunities one-against-another[25].

Given these realities, it is instructive to qualitatively rank the new sources of hydrocarbons that were being pursued shortly after the turn of the century against factors relating to cost and speed of experimentation, the number of players involved, and the degree of collaboration between players, which has been done in Figure 4 below.

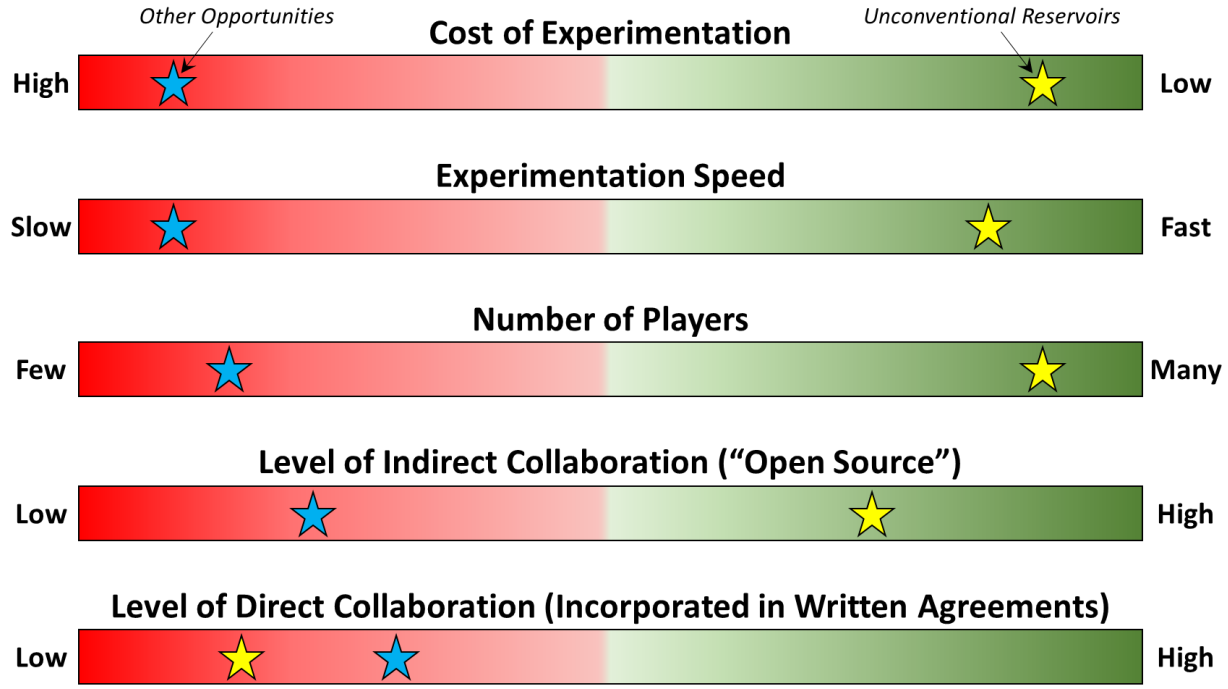

Figure 4. A slider bar representation of the innovation success factors noted in the text, with circumstances that are highly favorable for delivering successful outcomes being on the right side of the slider bars and unfavorable circumstances on the left. The approximate relative position of unconventional reservoirs and the other four opportunities that garnered significant funding from oil companies and governments during the 2000 to 2015 timeframe (arctic offshore; GTL; oil shale; gas hydrates) are shown by yellow stars for unconventionals and blue stars for the remaining four categories, which were grouped together because they have broadly similar characteristics. Please note that the "level of collaboration" factor has been broken into two subcategories to allow differences in approaches to be articulated in greater detail in the body of this paper. Please also note that the positioning of the stars are based upon the author's knowledge and perceptions, and the author realizes that other people may place them differently.

What stands out from this exercise is that unconventional reservoirs were advantaged in almost all the measures plotted, with cost and speed of experimentation both being superior to the other four opportunities, far more players being involved, and the ability to learn from others via "open source" methods being many times higher.

Breaking each innovation success factor down, it is worth noting the following:

- **Cost to Experiment:** The cost to experiment with technologies related to unconventional reservoirs was low because: i) experiments could be conducted in single wells in an onshore setting, ii) there was private ownership of surface and mineral rights, and iii) the equipment (e.g., rigs and frac units) and infrastructure (e.g., pipelines and processing facilities) needed to perform the experiments were for the most part readily available. Conversely, the cost to experiment with technological elements related to the other four opportunities were almost universally high given that: i) many of the resources to be developed were located in a harsh environment (e.g., arctic offshore, deep-water, or both), ii) governments owned the resources in most cases (e.g., arctic offshore; GTL; most gas hydrate deposits) and/or had imposed strict permitting criteria that needed to be overcome (arctic offshore; GTL; oil shale; gas hydrates), and iii) individual technology elements were part of complex, highly integrated systems, all parts of which needed to perform near perfectly for the system to function (e.g., GTL plants; in-situ oil shale extraction techniques).

- **Experimentation Speed:** Experimentation speed was much higher in unconventional reservoirs for the same reasons that experiments could be performed at relatively low cost. Turn-around times from one iteration of an experiment to the next could be as short as a few weeks, and because the cost to experiment was low, operators frequently tested competing approaches in parallel rather than in series. For all the other opportunities, learning by iterative field trials was a long-drawn-out process, taking years if not over a decade, with enormous investments of time and money being made before a technology was tested in the field since the cost of failure was extremely high.

- **Number of Players:** Whereas it is often perceived that if one has a good idea one should attempt to exclude all other parties from pursuing it either by patenting the idea or keeping it secret, more often than not, if the prize is sufficiently large and there are barriers that prevent a "winner take all" type of outcome (which is the case for the global energy business), having numerous players attempting to find a commercial solution will both greatly increase the probability of success and size of the prize (by lowering the per unit "cost of supply"[26]). That this was the case for unconventional reservoirs is clear with hindsight, with many tens of players entering the game after the first hints of success were achieved in the Barnett Shale, and the number of players scaling up to many hundred in only a few years, with each of the players pursuing somewhat different approaches and/or testing different geologic formations, thereby quickly providing feedback as to what worked and what didn't (or didn't work as well). Conversely, for all the other opportunities, participation was limited to a small number of very large companies by the cost to play the game, or in some cases, by cost to play and access to proprietary intellectual property (e.g., GTL, oil shale, gas hydrate solutions other than depressurization).

- **Level of Collaboration:** Closely linked to the "Number of Players" factor is the level of collaboration, since ultimately, the benefits associated with having more players is greatly diminished if information does not flow easily from one player to the next. It is therefore worth noting that where to place the stars on the two slider bars used to describe this factor was by far the most difficult choice the author had to make, because, except in cases where companies reveal that they worked together to achieve a solution, it is hard to judge whether convergence on similar technological solutions was achieved via collaboration or independently. However, for unconventional reservoirs, the speed at which similar approaches spread across basins strongly argues for a conclusion that the degree of collaboration was high, and because there were few if any joint ventures between companies pursuing unconventional E&P, this collaboration was of an indirect nature, in many ways analogous to the "open source" sharing of digital technology advancements that occurs in Silicon Valley and other high-tech hubs – sharing that has been credited with greatly accelerating the pace and lowering the cost of digital progress[27]. Conversely, there is little evidence for either effective direct or indirect collaboration associated with the other four opportunities that received significant funding between 2000 and 2015, with only a few joint ventures having been formed (e.g., government industry collaboration on gas hydrate production systems) and most experiments having been pursued in a way designed to protect intellectual property and avoid the sharing of knowledge gained.

As noted already, with hindsight, it is clear that unconventionals were the winning bet for investors who hoped to identify, commercialize, and scale new sources of economically producible hydrocarbons, with surging production from unconventional reservoirs having caused U.S. hydrocarbon production to more than double in less than 15 years (see Figure 5 on the next page), and production from unconventional reservoirs in Canada[28], China[29], Argentina[30], the Middle East[31], and elsewhere having begun to ramp up over the last several years.

So why did the technology development decision processes utilized by so many of the industry's largest companies prevent them from seeing that unconventionals were far more likely to provide a winning outcome than the opportunities they chose to pursue – opportunities that, except for Shell's Pearl GTL plant, are today not producing any hydrocarbons at all?

It is herein suggested that while there were many reasons for this outcome, one of the prime reasons is that **technology development decision processes seldom directly factor in the innovation success factors shown in Figure 4**, placing too much emphasis instead upon the perceived "size of the prize" and not appropriately appreciating the fact that assessments of probability of success are simply estimates – estimates that can only be resolved through experimentation.

This is of course problematic because innovation is typically a highly iterative process – one in which insights gained from experiments can both change perceptions about risk and the size of the prize, and also identify new, more favorable pathways to pursue, which makes opportunities where results from one's own experiments come quickly and cheaply, and results from experiments run by other players can also be accessed (even if imperfectly), appreciably advantaged over opportunities that do not possess these characteristics.

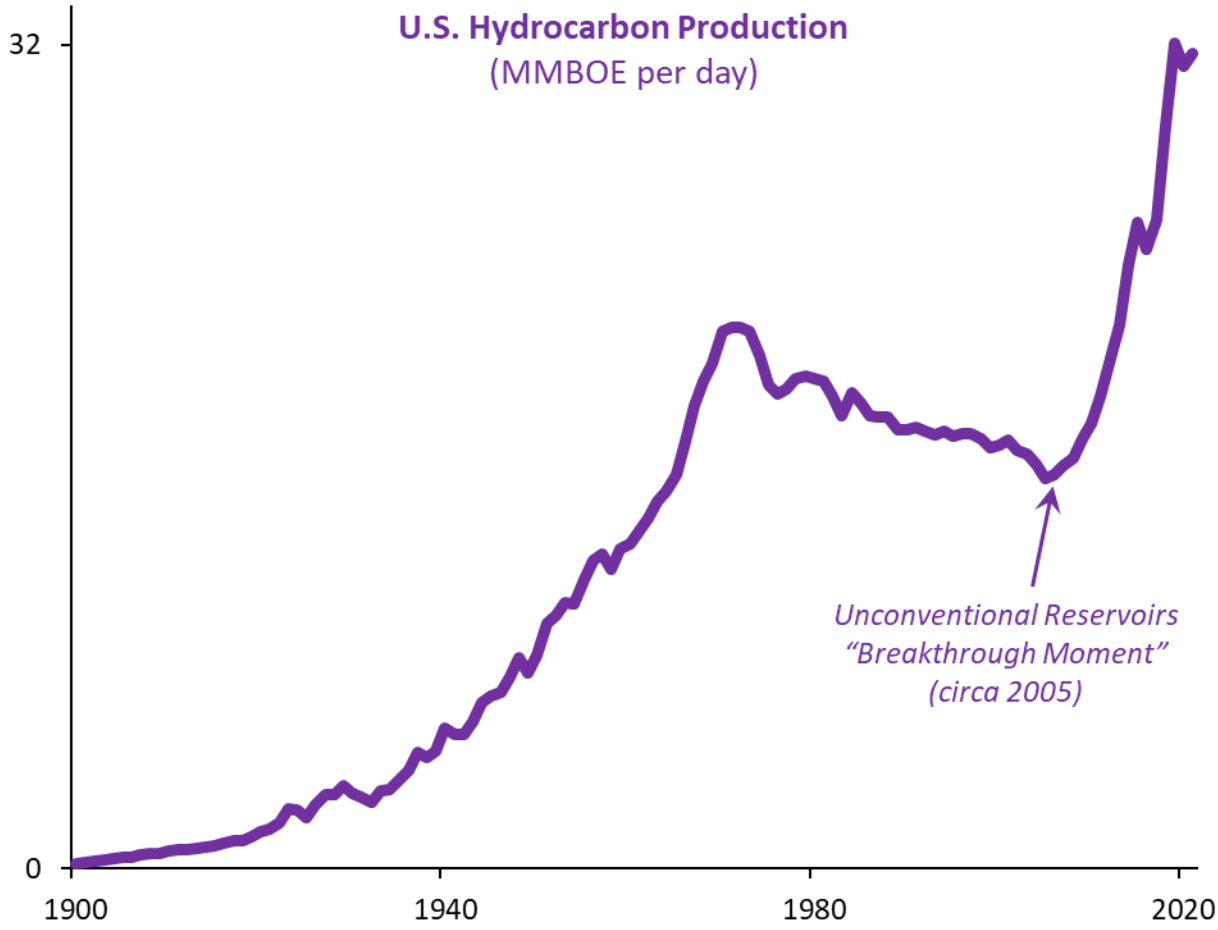

Figure 5. U.S. hydrocarbon production peaked in the early 1970s and had fallen to approximately 15 MMBOEPD by 2005. The unconventional reservoir revolution revived the U.S. industry, propelling the U.S. into the top spot amongst hydrocarbon producing nations, with U.S. production as of year-end 2021 being 9 MMBOEPD ahead of Russia and 19 MMBOEPD day ahead of Saudi Arabia, the 2nd and 3rd largest producers, respectively. 1965 to 2021 data taken from BP's 2022 Statistical Review of World Energy report. Pre-1965 oil production data taken from U.S. EIA's website. Pre-1965 gas volumes estimated from multiple sources.

So while it was not predestined that unconventional reservoirs would beat out the opportunities being pursued by major oil & gas companies, unconventionals reservoirs were hugely advantaged by the fact that each full-scale "experimentation cycle" cost relatively little to execute (a few hundred thousand to a few million dollars) and provided feedback extremely quickly (in a few weeks to a few months), whereas experimentation cycles for the opportunities pursued by the majors costs tens to hundreds of millions to billions of dollars each and took so long to complete that no opportunity finished more than one experimentation cycle between 2000 and 2015, and many were shut down before even one experiment could be completed (e.g., oil shale).

Furthermore, it is worth noting that the innovation success factors that were instrumental in allowing unconventional reservoirs to achieve its "breakthrough moment" were also crucial for allowing them to scale quickly, with scaling of the magnitude that enabled the U.S. to double its

hydrocarbon production in fifteen years having been enabled by continuous, rapid, low-cost, open-source experimentation that drove down industry average cost of supply to the point that unconventionals reservoirs rapidly garnered a disproportionate share of available industry funding.

Given that a similarly spectacular scaling of potential solutions will be required if humankind is to achieve a successful outcome to the climate-change-related energy transition that is currently underway, it is herein suggested that it is worth considering how the plethora of potential low-carbon energy technologies that are attracting investment might be prioritized using the "innovation success criteria" outlined in this paper, which is the topic discussed in the next section.

Applicability of Insights Gained and Lessons Learned to "*The Energy Transition*"

Observations that suggest there is a high degree of applicability of the oil & gas industry's experiences with navigating the transition it faced at the start of the 21st century to *The Energy Transition* include:

- When it comes to delivering solutions to technologically complex challenges, the ability to quickly execute low-cost experiments and learn from others are invaluable traits regardless of whether the challenge resides in the realm of oil & gas development or is much broader in scope.
- Human biases, blind spots, and decision-traps are technology challenge agnostic, being elements that negatively impact nearly every significant technology development related endeavor.
- As with the oil & gas industry's efforts to commercialize new sources of hydrocarbons, numerous potential solutions to *The Energy Transition* have been identified (e.g., nuclear fusion; advanced, large to small-scale nuclear fission; hydrogen; CCUS; geothermal energy; offshore wind; and advanced battery technologies), almost all of which are being championed by strong advocates expounding "compelling" investment theses.

It is therefore likely that, i) the "innovation success factors" that helped unconventional reservoirs win the race to supply new sources of hydrocarbons will be important in determining the outcome of the competition between technologies to deliver "low-carbon" energy solutions that is currently underway, and ii) these factors will be underappreciated by many of the players involved in the competition.

Regrettably, the author does not have deep knowledgeable about enough of the low-carbon energy solutions being pursued to opine authoritatively upon which ones, if any, are positioned to achieve a breakthrough of similar scale as unconventional reservoirs did – a breakthrough so large that it made pursuit of other solutions pointless, and which ones are more akin to the solutions that major oil & gas companies pursued unsuccessfully at great cost.

It is however believed that technology leaders responsible for selecting between potential low-carbon energy solutions will have enough information to incorporate these insights and lessons learned into their evaluations, with an example of how doing so might beneficially influence thinking about one specific potential solution being provided in the next section.

Geothermal Energy Example

Geothermal energy solutions are an interesting opportunity when it comes to cost and speed of experimentation, the number of players likely to be involved, and the ability to learn from others.

Geothermal solutions involving the harvesting of heat by flowing a fluid between wells through hydraulically created fractures are particularly intriguing given a player's ability to leverage knowledge gained not only from their own and others geothermal experiments, but also from the extensive body of knowledge derived since 2005 from the hundreds of billions of dollars invested in unconventional reservoir developments.

In fact, as is shown in Figure 6, it is the delta between the approaches that have been used to date to exploit geothermal energy sources and the applicable technological capabilities developed for extracting hydrocarbons from unconventional reservoirs that make this opportunity potentially exciting.

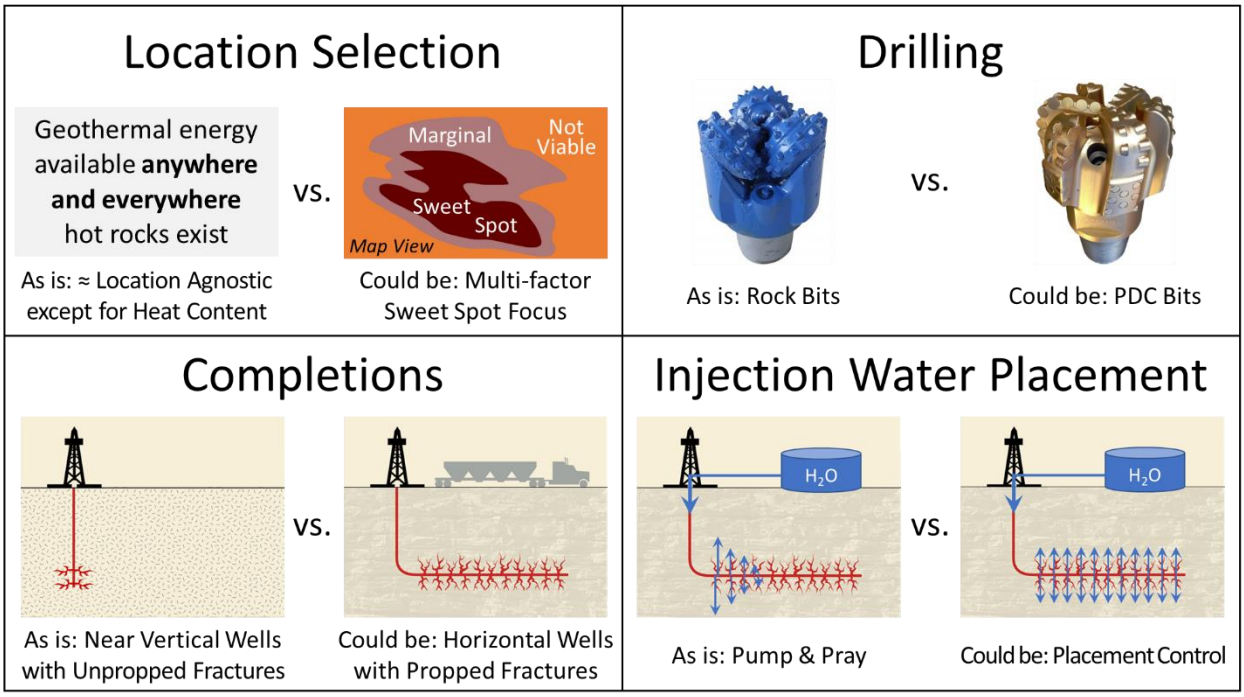

Figure 6. A comparison of past practices utilized for extracting geothermal energy using induced fractures with state-of-the-art practices used by the oil & gas industry for developing unconventional reservoirs, and in the case of injection water placement, improving recovery from conventional oil fields.

By way of building out the story encapsulated in Figure 6, it is worth noting the following:

- As was the case in the early days of unconventional reservoir exploration when many players invoked a "statistical drilling" paradigm to explain differences in well results within "play fairways", and therefore failed to appreciate that the interaction of several key geologic factors controlled the location of "sweet spots", geothermal exploration seems to overemphasize heat content and underappreciate other geologic factors, especially factors

related to rock type and stress conditions, although to be fair to the geothermal industry, this is undoubtedly due in large part to a paucity of subsurface data since few wells have been drilled very far into “basement rock” formations, and even fewer wells have gathered significant geologic data in such settings.

- Recent results of experiments performed to determine whether PDC bits could improve drilling speeds in “hard rocks” have been encouraging[32], with PDC bits having significantly outperformed the rock bits traditionally used to drill “hard rock” geothermal wells with regards to both rate of penetration and bit life during trials performed at the FORGE project in Utah (Figure 7).

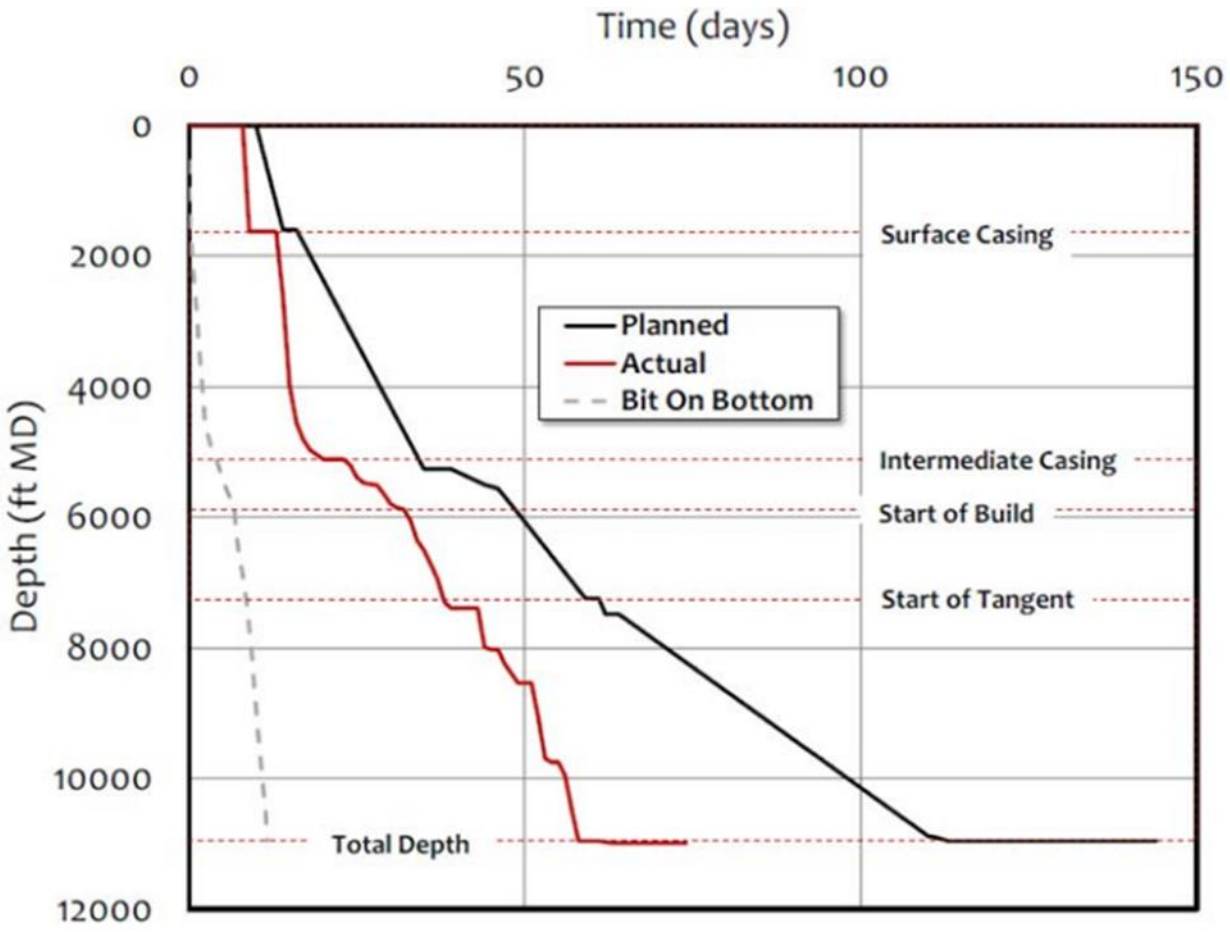

Figure 7. Plot showing planned versus actual time to complete drilling operations at a recent well at the Utah FORGE project that included a 5300-ft 65° tangent section in a hard granitic formation at temperatures up to 450°F (232°C) and proved the viability of using PDC bits in “hard rock” formations. Importantly, “bit on bottom” time was only approximately ten days, which indicates that considerable improvements in total time should be possible. Figure taken from paper by Sugiura et al, 2021[33].

- As in the early days with unconventional reservoirs, completion design is the area most ripe for improvement, with almost all geothermal wells that have been drilled to date having been drilled vertically, and for geothermal wells that have been fracture stimulated, hydraulic fracturing having generally been carried out without the use of proppant.

- The use of vertical or near-vertical wells to form injector / producer geothermal well pairs makes achieving hydraulic connections between paired wells extremely difficult given the limited width of fracture zones nucleated from perforations in vertical to near-vertical wells. Switching to horizontal or near-horizontal well designs should therefore greatly improve the likelihood and quality of connectivity, although it should be noted that unlike with unconventional fracture stimulated wells that are produced back into the well the fractures emanate from, geothermal fracture stimulated development plans will require injection-well-to-production-well connections to be made, thereby significantly increasing the importance of understanding controls on fracture geometry in the subsurface (and the value of having geologic and engineering fracture expertise within one's company).
- When it comes to the evolution of unconventional reservoir well designs, no element has undergone more rapid and greater changes than the modifications that have occurred around proppant volume and proppant placement methods. Proppant volumes have increased enormously on both a per well and per perf cluster basis, perf cluster spacing has decreased from hundreds of feet between each cluster to a few feet to tens of feet, the type of proppant used has evolved in almost every region, moving from higher performance / higher cost proppants to more readily available, lower cost alternatives, and fluid volumes and composition have undergone dramatic changes. These changes have been driven by empirical results and the acquisition of robust subsurface and production data. And while it is difficult to prejudge what approach might work best in creating complex, high-flow-rate pathways between injector / producer pairs in geothermal reservoirs, much improvement is seemingly possible.
- As is well documented from waterfloods and other types of injection-related improved recovery techniques used in oil reservoirs, managing the placement of injectants to ensure uniform flow through the reservoir and prevention of short-circuiting is crucial for maximizing recovery[34]. This will also be critical for geothermal developments where the heat recovery mechanism relies on flowing fluid between wells, with the "pump & pray" methods currently being utilized making this an element ripe for technology transfer and/or development.

Strategies for Selecting Amongst a Plethora of Technology Choices – Closing Thoughts

It has often been claimed that novel innovations are far more likely to be produced by small, entrepreneurial companies or individual entrepreneurs than by large, established firms[35].

And at first glance, the story of the unconventional reservoir revolution certainly seems to fit with this hypothesis, with the viability of extracting hydrocarbons at commercial rates from ultra-low permeability reservoirs having been proven up by George Mitchell, who earned a degree in petroleum engineering with an emphasis in geology from Texas A&M university in 1940, formed an independent oil & gas company while serving in the Army Corps of Engineers during World War II, and throughout a nearly six-decade long career in the oil & gas industry distinguished himself as an innovator par excellence – an innovator who, starting in 1981, experimented for over twenty years with methods to extract gas at commercial rates from the Barnett Shale before

achieving the initial completion and well design breakthroughs that would peak the curiosity of numerous other companies[36], drawing in at first other independent operators, and eventually companies of larger and larger scale as the search for unconventional reservoir "sweet spots" rapidly expanded from the Barnett Shale to other "shale gas" plays, and eventually targeted unconventional oil reservoirs as well.

However, an alternative explanation that could be drawn from the broader history of how unconventional reservoirs beat out novel technologies being pursued by major oil & gas companies during the same time frame would be that **knowledge gained from experimentation is the most important factor in the achievement of breakthroughs**, with the size of the companies involved being of secondary importance.

That this is a viable explanation is supported by the following observations:

- The opportunities pursued by major oil & gas companies were no less novel than the idea of extracting hydrocarbons from shale, with two of the opportunities – gas hydrates and oil shale – being strikingly similar to unconventional reservoirs regarding the crux of the challenge that needed to be overcome in that they required the development of technologies to extract hydrocarbons that were like shale gas, essentially "locked in rocks" (i.e., the hydrocarbons were for all intent and purposes immovable using existing subsurface extraction technologies).
- For oil shale, both Chevron[15] and ExxonMobil[16] conceived of innovative extraction methods that involved hydraulic fracturing, which, as is now obvious, was one of the key technologies that enabled the unconventional reservoir revolution.
- The amount of monetary and human resources committed by the majors to develop solutions to the challenges inherent in the opportunities they pursued were far greater in absolute terms than those committed by Mitchell Energy and other early movers in unconventional reservoirs.
- And the level of perseverance shown by the majors was on par with that of independent oil & gas companies pursuing unconventional reservoirs, with the timelines of the technology development projects the majors pursued almost all exceeding a decade in duration, and many of the projects requiring significant regulatory and political hurdles to have been overcome.

It is therefore believed that the correct explanation for why unconventional reservoirs were successful and the other opportunities failed has mostly to do with the innovation success factors outlined in this paper, with these factors, in the final analysis, being crucial for the attainment of knowledge – knowledge that can come from either one's own experiments or those performed by other players – knowledge that can help an innovator by redirecting their efforts towards new, more promising pathways related to an opportunity they are pursuing or by encouraging them to terminate efforts that seem far less promising than initially believed, thereby freeing up resources to pursue other opportunities.

These factors should thus be given greater weight than they seemingly traditionally are in making and updating technology development investment choices, with this being true both for oil & gas related technologies and the plethora of technologies currently being pursued to help achieve *The Energy Transition* – a transition required to limit climate change impacts related to the rapid buildup of greenhouse gases in the atmosphere and oceans.

Finally, it is worth noting that while small companies and individual entrepreneurs naturally have to focus on rapid, low-cost experimentation and learning from other players because they have limited resources to support more expansive efforts, there is nothing preventing large companies from prioritizing investments with similar characteristics, except perhaps for the (mistaken) belief that for a technology development project to have an impact on a large company's bottom line, it must have mega-project-like characteristics (e.g., investing in technologies to commercialize production from ice-covered portions of the offshore Arctic, oil shale, gas hydrate deposits, and gas-to-liquids conversion, all of which required expensive, multi-year to decade plus long commitments to be made).

Unfortunately for most of the oil industry's major companies, the size of the unconventional reservoir prize was initially seen as being too small to be of interest[37], likely because they focused on well-scale rather than play-scale resource and economic numbers, condemning all of them, except for Chevron, who had large, legacy mineral interest holdings in the Permian Basin, to have to pursue "play entry" primarily via acquisitions rather than leasing, which, while it can be a viable means to build a position, is usually expensive once industry participants realize that a breakthrough of enormous size has been achieved.

It is therefore worthwhile for large companies to avoid falling into the trap of ignoring or underweighting what might appear at first glance to be "small or niche company" opportunities <u>if</u> the opportunities allow for rapid, low-cost experimentation and could represent a substantial business when considered in whole rather than in part.

Notes

1. Daniel Yergin, “The Prize: The Epic Quest for Oil, Money & Power”, Simon & Schuster, 1991.

2. From reports about exploration success rates by Woodmac, IHS, Rystad, and other industry technical analysts published between 2005 and 2015.

3. For details about timing of the discovery of conventional supergiant oil & gas fields, see Edgar Wesley Owen’s publication, “Trek of the Oil Finders: A History of Exploration for Petroleum”, AAPG Memoir Volume 6, 1975; Richard Nehrig’s report “Giant Oil Fields and World Oil Resources”, which was prepared for the U.S. Central Intelligence Agency and was published by the RAND Corporation in 1978; or Figure 8 below. Details about levels of output from supergiant oil & gas fields circa 2000 can be found in numerous publications, including but not limited to: Mikael Höök et al., “Giant oil field decline rates and their influence on world oil production”, Energy Policy, Volume 37, Issue 6, June 2009, Pages 2,262 to 2,272. Information about country-scale levels of oil and gas production can be found in BP’s annual World Energy Statistics publications.

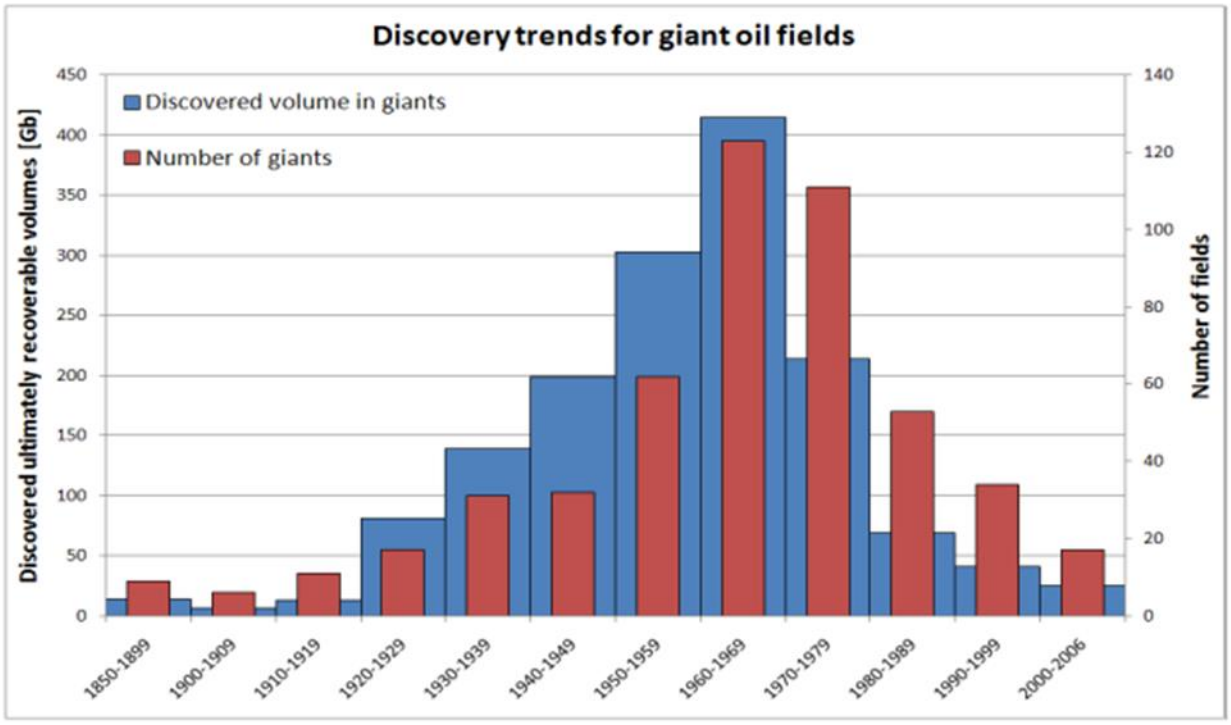

Figure 8. Plot showing discovery history for fields containing greater than 0.5 billion barrels of oil. As shown in the plot, the peak period for discovery both in terms of volume and number of fields was from 1960 to 1969. Figure taken from Mikael Höök et al., “Giant oil field decline rates and their influence on world oil production”, Energy Policy, Volume 37, Issue 6, June 2009.

4. BP’s annual World Energy Statistics publications.

5. See U.S. Energy Administration (EIA) Biofuels production data, which is available on their website (https://www.eia.gov/totalenergy/data/monthly/pdf/sec10_7.pdf).

6. Margaret Kriz Hobson, "Shell abruptly exits Chukchi drilling", E&E News Energywire, September 28, 2015 (https://www.eenews.net/articles/shell-abruptly-exits-chukchi-drilling/); also, "Shell pulls arctic plug, looks at $4.1 billion in impairments", Oil & Gas 360°, September 28, 2015 (https://www.oilandgas360.com/shell-pulls-arctic-plug-looks-at-4-1-billion-in-impairments/).

7. Scott Haggett, "BP bids big for Canadian Arctic drilling rights", Reuters, June 9, 2008 (https://www.reuters.com/article/canada-energy-arctic-idUSN0947438920080609).

8. Gary Park, "Canadian Beaufort drilling years away, possibly late this decade", Petroleum News, April 28, 2013 (https://www.petroleumnews.com/pntruncate/194159153.shtml).

9. "Keppel and ConocoPhillips join forces to develop Arctic jack-up drilling rig", Energy Voice, June 3, 2012 (https://www.energyvoice.com/oilandgas/24791/keppel-and-conocophillips-join-forces-to-develop-arctic-jack-up-drilling-rig/).

10. "Pearl GTL", Wikipedia, as accessed on December 1, 2022 (https://en.wikipedia.org/wiki/Pearl_GTL).

11. "The world's largest gas-to-liquids plant", Shell website, as accessed on December 2, 2022 (https://www.shell.com/about-us/major-projects/pearl-gtl/the-world-s-largest-gas-to-liquids-plant.html).

12. "Qatar's Pearl GTL to hit full capacity in days", Reuters, September 24, 2012 (https://www.reuters.com/article/qatar-gtl-capacity-idUSL5E8KO58E20120924).

13. "Shell in situ conversion process", Wikipedia, article was accessed on December 1, 2022 (https://en.wikipedia.org/wiki/Shell_in_situ_conversion_process); also, "Plan of Operations, Oil Shale Test Project", Shell Frontier Oil and Gas Inc., February 15, 2006.

14. Personal communication from Shell technology leader, 2014.

15. "Chevron CRUSH", Wikipedia, article as it appeared on Wikipedia on December 1, 2022 (https://en.wikipedia.org/wiki/Chevron_CRUSH).

16. Joao Peixe, "ExxonMobil Takes Step Forward on Colorado Oil Shale", oilprice.com, March 18, 2014 (https://oilprice.com/Latest-Energy-News/World-News/ExxonMobil-Takes-Step-Forward-on-Colorado-Oil-Shale.html); also, "ExxonMobil Electrofrac", Wikipedia, this article was accessed on December 1, 2022 (https://en.wikipedia.org/wiki/ExxonMobil_Electrofrac).

17. "Red Leaf Resources, Inc. & Total E&P USA Oil Shale, LLC Announce a Joint Venture for Oil Shale Production Project", Marketwatch, April 18, 2012 (https://www.thecre.com/oil/?p=146).

18. Lin Chen and Sukru Merey, "Oceanic Methane Hydrates – Fundamentals, Technological Innovations, and Sustainability", Gulf Professional Publishing, 2021.

19. "Methane Hydrate Field Studies", U.S. Department of Energy Office of Fossil Energy and Carbon Management website (https://www.energy.gov/fecm/methane-hydrate-field-studies).

20. David Schoderbek, Helen Farrell, Keith Hester, James Howard, Kevin Raterman, Suntichai Silpngarmlert, Kenneth Lloyd Martin, Bruce Smith, and Perry Klein, "ConocoPhillips Gas Hydrate Production Test Final Technical Report", U.S. Department of Energy National Energy

Technology Laboratory website, Report was submitted to the DOE on July 20, 2013, (https://www.netl.doe.gov/sites/default/files/netl-file/nt0006553-final-report-hydrates_0.pdf).

21. "Japan reports successful gas output test from methane hydrate", Reuters, May 8, 2017 (https://www.reuters.com/article/japan-methane-hydrate-idUSL4N1IA35A); see also "Japan to conduct second test to produce gas from methane hydrate", Reuters, April 9, 2017 (https://www.reuters.com/article/japan-methane-hydrate-idINL3N1HI1KA).

22. Jin-fa Li et al., "The first offshore natural gas hydrate production test in South China Sea", China Geology, Volume 1, Issue 1, March 2018.

23. Daniel Kahneman, "Thinking Fast and Slow", Farrar, Straus and Giroux, April 2013; also, Richard Thaler, "The Winner's Curse: Paradoxes and Anomalies of Economic Life", Simon & Schuster, 1991.

24. Ian Lerche and James A. MacKay, "Economic Risk in Hydrocarbon Exploration", Elsevier Inc., 1999; also, the author's experience with over 25 years of reviewing post-audited results from exploration drilling programs.

25. Personal experience as well as communications from the leaders of other companies' hydrocarbon exploration drilling programs.

26. ConocoPhillips' definition for "Cost of Supply" is as follows: "*Cost of supply is the WTI equivalent price that generates a 10% after-tax return on a point-forward and fully burdened basis. Fully burdened includes capital infrastructure, foreign exchange, price-related inflation, G&A and carbon tax (if currently assessed). If no carbon tax exists for the asset, carbon pricing aligned with internal energy scenarios are applied. All barrels of resource in the cost of supply calculation are discounted at 10%"*.

27. Justin Reock, "Top 5 Benefits of Open Source Software", Open Logic, April 2020 (https://www.openlogic.com/blog/top-5-benefits-open-source-software); see also, "Introduction to Open-Source and its benefits", Geeks for Geeks, January 2021 (https://www.geeksforgeeks.org/introduction-to-open-source-and-its-benefits/); see also "5 ways open source is reshaping, development, collaboration and society", Intuit, 2019 (https://techcrunch.com/sponsor/intuit/5-ways-open-source-is-reshaping-development-collaboration-and-society/).

28. Brad Hayes, "The Current State of Canadian Unconventional Oil and Gas Plays", Society of Petroleum Engineers (SPE) The Way Ahead, July 2018 (https://jpt.spe.org/twa/current-state-canadian-unconventional-oil-and-gas-plays).

29. Pat Davis Szymczak, "China's Unconventional Challenge Spurs New Thinking on Shale and Tight Reservoirs", SPE Journal of Petroleum Technology, February 2021 (https://jpt.spe.org/chinas-unconventional-challenge-spurs-new-thinking-on-shale-and-tight-reservoirs).

30. Paola Romero, “Argentina: Unconventional Activity Update”, S&P Global Commodity Insights, May 2020 (https://www.spglobal.com/commodityinsights/en/ci/research-analysis/argentina-unconventional-activity-update.html); “Chevron Worldwide Operations: Argentina”, accessed on Chevron’s website, December 2022 (https://www.chevron.com/worldwide/argentina).

31. Tsvetana Paraskova, “Saudi Aramco Seeks Investors For $110 Billion Unconventional Gas Project”, oilprice.com, December 12, 2022 (https://oilprice.com/Latest-Energy-News/World-News/Saudi-Aramco-Seeks-Investors-For-110-Billion-Unconventional-Gas-Project.html).

32. Junichi Sugiura et al., “Oil and Gas Drilling Optimization Technologies Applied Successfully to Unconventional Geothermal Well Drilling”, Paper presented at SPE Annual Technical Conference and Exhibition held in Dubai, UAE, 21 - 23 September 2021.

33. Duane Winkler and Leroy Swearingen, “Summary of Drilling Activities: Well 16A(78)-32”, U.S. Department of Energy FORGE Project, March 2021 (https://gdr.openei.org/submissions/1296).

34. Chris Carpenter, “Best Practices for Waterflooding Optimization Improve Oil Recovery in Mature Fields”, SPE Journal of Petroleum Technology, January 1, 2019 (https://onepetro.org/JPT/article/71/01/58/208351/Best-Practices-for-Waterflooding-Optimization).

35. Clayton Christensen, “The Innovator’s Dilemma: When New Technologies Cause Great Firms to Fail”, Harvard Business School Press, 1997.

36. Dan Steward, “George P. Mitchell and the Barnett Shale”, SPE Journal of Petroleum Technology, October 31, 2013 (https://jpt.spe.org/george-p-mitchell-and-barnett-shale).

37. Personal communication from a senior ExxonMobil leader who related how ExxonMobil executive leadership turned down a recommendation made by several of the company’s subject matter experts to pursue unconventional reservoir opportunities soon after Mitchell Energy achieved its breakthrough in the Barnett Shale. ExxonMobil executive leadership indicated that “while unconventional reservoirs might be of interest to independent operators, they were too small for a company like ExxonMobil to pursue”. ExxonMobil of course later revised this decision and went all in on unconventionals, purchasing XTO for $41 billion in 2009 and several companies owned by the Bass Family for $5.6 billion in 2017. Their delay however cost them dearly, mostly eliminating the opportunity for them to purchase acreage early on at relatively low prices directly from mineral owners, as was done by Devon, ConocoPhillips, Pioneer, EOG, and many other earlier movers.