United States hydraulic fracturing’s short-cycle revolution and the global oil industry’s uncertain future

Gabe Eckhouse
University of California, Berkeley, Department of Geography, 505 McCone Hall #4740, Berkeley, CA 94720-4740, United States

ARTICLE INFO
Keywords:
Fracking
Shale boom
US hydraulic fracturing
Energy transition
Future of oil
Materiality of oil

ABSTRACT
The global oil industry has entered into a period of debilitating uncertainty. Two forces—renewable energy and price volatility—call into question the profitability of investing in the massive, decades-long conventional projects which form the backbone of global production. Facing a volatile, unknown future, energy financiers are retracting from long-term projects. United States (US) hydraulic fracturing has offered a partial solution. The unique material properties of hydraulic fracturing give it—relative to conventional production—a small investment scope with a short cycle of production. This flexible production process has helped sections of the industry avoid the commodity’s uncertain outlook by narrowly focusing on the near term. However, hydraulic fracturing, while offering a different temporal and financial scale of investment, is often more expensive per barrel. Confronted by COVID-19 disruptions, massive debt, and public contestation, some predict the end of fracking, as the least profitable, most indebted players go under. This paper hypothesizes that intensifying uncertainty over the future of oil—above all from the renewable energy transition—will, however, ironically further stimulate this destructive form of extraction.

1. Introduction

“How the world will generate and consume energy in the future has never been more in doubt.” – Houston Chronicle, 2018

Oil remains the single largest source of energy in the world economy (BP, 2020). Of the top 10 global companies by revenue, six of them are oil and gas and two are car companies (Fortune, 2020). However, despite its present-day significance, never in history has its future been so unclear.

Two forces disrupt oil’s future. First, the industry fears the encroachment of renewable energy as it endangers future oil demand (Nasser, 2018). Oil companies, state-owned and private alike, face a paradox. Their investments are largely composed of decades-long projects that require billions of dollars of up-front capital investment. Yet, investing in these traditional projects poses extreme risks, given the extraordinary uncertainty over both the future demand for and price of oil.

Amidst this growing state of uncertainty for conventional production, one of the largest national oil booms in history has taken place. Hydraulic fracturing, or shale oil, increased US oil production by about 7 million barrels per day in one decade (EIA, 2019). Bloomberg (2017) has described fracking as the “biggest boom in world history,” with Saudi Arabia’s post-war expansion a close second. After years of declining production, the US became the world’s largest oil producer in 2018 (EIA, 2018), a cause of celebration for US geopolitical strategists (Atlantic Council, 2012; Brookings, 2018).

1 The hydraulic fracturing of tight shale formations is commonly called hydraulic fracturing (fracking), shale oil (shale), or tight oil (LTO). Confusingly, a different process, called “oil shale,” refers to the production of liquid fuels by mining kerogen shales and subjecting them to extreme heat and pressure, see for example (Rama, 2013).

https://doi.org/10.1016/j.geoforum.2021.07.010
Received 11 September 2020; Received in revised form 7 June 2021; Accepted 8 July 2021
Available online 9 August 2021
0016-7185/© 2021 The Author(s). Published by Elsevier Ltd. This is an open access article under the CC BY-NC-ND license
(https://creativecommons.org/licenses/by-nc-nd/4.0/).
This paper argues that a core feature of the US fracking expansion has been its ability to provide investors a unique relief from the long-cycle production that dominates the global oil industry. Fracking has a qualitatively, materially different temporal and physical scale of production compared to new conventional wells—one that allows for short, granular investment opportunities that new conventional production does not. Where new, major conventional fields cost billions of dollars, take several years to begin, and a decade or more to produce from, a hydraulic fracturing well costs $10 million or less, takes a few months to set up, and produces the majority of its oil within a few years. It provides a flexible means by which investors can extract oil, distinct from the mainstream industry.

Because of its unproven, novel character, the high costs associated with its production, and the small scale of its individual wells, fracking was pioneered by small and medium-sized firms. Without the war chests of the major oil companies, these fracking innovators relied on Wall Street. Ultra-low interest rates, established during the Federal Reserve’s response to the 2008 financial crisis have played a key role in ensuring capital reaches these small firms (McCLean, 2018). Likewise, the general government subsidization of oil development in the US and pro-oil regulations, or lack thereof, have fueled its emergence (Counts and Block, 2016; Neville, et al., 2017, Baka, et al., 2018). These political and financial conditions combined with the US’s extensive pre-existing oil and gas infrastructure, large resource base, and expertise to mainly limit the oil fracking boom to the US and parts of Canada (UN Conference on Trade and Development, 2018; Forbes, 2013). However, many firms entered into risky, debt-laden deals that underscore a major downside of hydraulic fracturing for the industry: per barrel, it is more expensive than many currently producing conventional fields (Rystad, 2019). While fracking became attractive to upstream investors as the price rose and the technique advanced, the smaller firms that pioneered fracking burned through borrowed cash as they worked to develop it (WSJ, 2018). Now, a consolidation is taking place with many of these smaller players at the end of their rope.

In this paper I tell a complementary but not exclusive story of how the materialities of fracking’s production, or labor process have played a major role in a general shift among North American (NA) upstream oil investors, including the international oil companies (IOCs), towards shale. This paper does not seek to explain, in its entirety, the rise of hydraulic fracturing in the United States. Rather I draw out an important aspect of its development not yet examined in energy geographies.

Empirically this paper relies on communication, analysis, and data from within the oil and gas industry. I draw on reports, conference proceedings, speeches, and news interviews aimed at an inner-industry audience, a kind of archive of upstream oil capitalist thought. Capitalism is a dynamic system and the materialities of capital accumulation change over time. This is why I acknowledge the “constant change” thesis of the early 20th-century German geographer Alfred Weber when he claimed the “amorphous form of production” of natural resources is a “metamorphosis” in the “social productive process” (Weber, 1921). I combed through this material between 2017 and 2020 as part of dissertation research, collating the industry’s evolving understanding of the importance of hydraulic fracturing’s material properties. My sources fall into several categories. The first is global oil and gas companies, both IOCs and national oil companies (NOCs), whose official reports, and communications from leading members, reveal the shifting attitudes of key decision-makers. The second is reports from energy consulting firms such as Rystad, McKinsey, Deloitte, and others, whose analyses are frequently relied on by capital allocators. Finally, I draw on the financial press.

In the next section I review geographic thought on the materiality of oil and natural resources. I suggest examining the materiality of oil’s distinct labor processes can develop our understanding of social-nature relations in oil production. Likewise, I note how this paper can contribute to geographic work on hydraulic fracturing and discussions on the embedded character of fossil capital in face of climate change. In the third section I provide background evidence on the growing state of uncertainty and volatility in global oil markets, showing that this has globally discouraged long-cycle production. Then, in the fourth section, I demonstrate how hydraulic fracturing’s unique labor process results in flexible, short, granular investment scales which have been critical to attracting NA upstream capital. The fifth, final section suggests hydraulic fracturing may ironically benefit from the renewable energy transition, as the future of energy remains uncertain, volatile, and contested.

2. The materiality of oil production

Central to this paper is the relationship between oil investment and the material properties of different types of oil extraction, or labor processes. Geographers have been concerned for some time with how the materiality of natural resources play a role in their social reproduction (Balmaceda, et al, 2019). Bakker and Bridge (2006) for a key concept, the materiality of oil and gas infrastructure, large resource base, and expertise to mainly limit the oil fracking boom to the US and parts of Canada (UN Conference on Trade and Development, 2018; Forbes, 2013). However, many firms entered into risky, debt-laden deals that underscore a major downside of hydraulic fracturing for the industry: per barrel, it is more expensive than many currently producing conventional fields (Rystad, 2019). While fracking became attractive to upstream investors as the price rose and the technique advanced, the smaller firms that pioneered fracking burned through borrowed cash as they worked to develop it (WSJ, 2018). Now, a consolidation is taking place with many of these smaller players at the end of their rope.

In this paper I tell a complementary but not exclusive story of how the materialities of fracking’s production, or labor process have played a major role in a general shift among North American (NA) upstream oil investors, including the international oil companies (IOCs), towards shale. This paper does not seek to explain, in its entirety, the rise of hydraulic fracturing in the United States. Rather I draw out an important aspect of its development not yet examined in energy geographies. I have examined the material properties of oil production in the United States. However, many firms entered into risky, debt-laden deals that underscore a major downside of hydraulic fracturing for the industry: per barrel, it is more expensive than many currently producing conventional fields (Rystad, 2019). While fracking became attractive to upstream investors as the price rose and the technique advanced, the smaller firms that pioneered fracking burned through borrowed cash as they worked to develop it (WSJ, 2018). Now, a consolidation is taking place with many of these smaller players at the end of their rope.

Empirically this paper relies on communication, analysis, and data from within the oil and gas industry. I draw on reports, conference proceedings, speeches, and news interviews aimed at an inner-industry audience, a kind of archive of upstream oil capitalist thought. Capitalism is a dynamic system and the materialities of capital accumulation change over time. This is why I acknowledge the “constant change” thesis of the early 20th-century German geographer Alfred Weber when he claimed the “amorphous form of production” of natural resources is a “metamorphosis” in the “social productive process” (Weber, 1921). I combed through this material between 2017 and 2020 as part of dissertation research, collating the industry’s evolving understanding of the importance of hydraulic fracturing’s material properties. My sources fall into several categories. The first is global oil and gas companies, both IOCs and national oil companies (NOCs), whose official reports, and communications from leading members, reveal the shifting attitudes of key decision-makers. The second is reports from energy consulting firms such as Rystad, McKinsey, Deloitte, and others, whose analyses are frequently relied on by capital allocators. Finally, I draw on the financial press.

In the next section I review geographic thought on the materiality of oil and natural resources. I suggest examining the materiality of oil’s distinct labor processes can develop our understanding of social-nature relations in oil production. Likewise, I note how this paper can contribute to geographic work on hydraulic fracturing and discussions on the embedded character of fossil capital in face of climate change. In the third section I provide background evidence on the growing state of uncertainty and volatility in global oil markets, showing that this has globally discouraged long-cycle production. Then, in the fourth section, I demonstrate how hydraulic fracturing’s unique labor process results in flexible, short, granular investment scales which have been critical to attracting NA upstream capital. The fifth, final section suggests hydraulic fracturing may ironically benefit from the renewable energy transition, as the future of energy remains uncertain, volatile, and contested.

2. The materiality of oil production

Central to this paper is the relationship between oil investment and the material properties of different types of oil extraction, or labor processes. Geographers have been concerned for some time with how the materiality of natural resources play a role in their social reproduction (Balmaceda, et al, 2019). Bakker and Bridge (2006) called for a “research agenda that addresses the analytical significance of concrete differences in the material world and the way these enable and constrain the social relations necessary for resource production.” Sneddon (2007), as an example, shows how the biophysical characteristics of riverine fisheries “dictate strategies of appropriation” both for capitalist and self-subsistence use. This paper similarly demonstrates how “concrete differences in the material world” (Bakker and Bridge, 2006) of oil production sculpt upstream oil investment strategies in important ways beyond cost.

Within oil, Timothy Mitchell’s Carbon Democracy (2011) has related that the material qualities of coal production allowed for forms of working-class resistance which oil production did not. While widely praised, Carbon Democracy has been criticized for bordering on “a form of energy reductionism” (Huber, 2013). Specifically, geographers criticized ‘peak oil,’ which claimed that material limits to extraction would force production to globally decline. Geographers argued that this movement construed “oil scarcity as a geologic fact,” rather than “a social relationship,” (Huber, 2013) and snapped “analysis back into a materialist position that forecloses argument about the social organization of oil production” (Bridge, 2011). Peak oil did not adequately reckon with the economic and technical forces which determine the quantity of oil reserves, nor how the financialization of oil promoted fictitious capital formations (Labban, 2010) to which oil companies performed for with reports about their future (Zalik, 2010). Geographers emphasized oil’s history was not one of dearth, but excess, requiring state violence to create scarcity (Huber, 2011; Nitzan and Bichler, 2002).

While these authors criticized environmental determinist approaches to materiality, they did not, however, seek to discount materiality full cloth. Huber’s Lifeblood (2014) structures itself around “specific aspect[s] of the materiality of oil,” emphasizing “how the biophysical attributes of oil itself—its dense energy, its liquid propensity to flow, its chemical composition—actively shape not only the politics of oil but also politics more broadly.” Bridge (2011) shows that several “troublesome social relations” associated with oil bear the “imprint” of its materiality. This is akin to Kaup (2008) who notes how the “uncooperative commodity” character of natural gas coincides with its challenging
properties generate such explosive consequences among the oil pro-

tigation of geologic, technical, economic, and political processes (Sayer,

- 1979; Benton, 1989). Focusing on this relationship helps avoid a binary

- society–nature argument in which oil is either determined socially or

- Naturally. Producing oil is a mediation between, on the one hand, the

- materiality and geology of oil, and, on the other, the forces of capitalist

- production, including labor, technique, state relations, and finance. By

- emphasizing the extraction process as this nexus of relationships, my

- approach is reminiscent of Zalik and Killoran-McKibbin’s (2016) call to

- de-emphasize the productive-extractive binary to avoid a “reified divi-

- sion between human labour and nature.” It likewise relates to Baka and

- Vaishnava’s (2020) call for “materializing energy” by developing our

- understanding of the “metabolic processes enabling energy systems.”

- This approach, however, is distinct from existing literature in a two

- ways. First, it does not approach the attributes of oil abstractly as a

- resource (see: Watts 2001), but rather engages directly with the concrete

- reality of its production process. As such, I do not see oil’s materiality

- singularly (Bridge, 2011) but rather variegated by its different methods

- of extraction. This emphasis is especially important today as new forms

- of energy production, such as unconventional hydrocarbons and re-

- newables, emerge – each with their unique properties. Second, most

- existing literature tends to overlook the importance of oil’s material

- qualities broadly, this, in contrast, provides a longer-form investigation

- of a specific extractive process. This paper returns in ways to Mitchell

- (2011) by focusing on the impact of the labor process; however, this

- essay is not concerned with governance but rather oil’s dysfunctional

- political economy during the energy transition.

- By focusing on the materiality of hydraulic fracturing’s labor process

- I am not attempting a comprehensive account of the US fracking boom.

- Rather, I explore a crucial but overlooked aspect of this new mode of

- extraction. I hope geographers examining aspects of fracturing – for

- example, contested environmental knowledge, popular resistance, sites

- of extraction, and rules and regulations – find this paper’s conclusions

- useful as a kind of economic or technical backdrop; however, it is not

- intended as a substitute for broader assessments of the politics inter-

- woven into its rise (Lave & Lutz, 2014; Neville et al. 2017; Baka, et al.,

- 2019; Kinchy et al., 2016; Bridge and Le Billon, 2017).

- This paper can also contribute to another conversation in energy

- geographies (Calvert, 2016; Huber, 2015) on the locked-in, inter-

- connected energy system (Calvert, 2017) of fixed fossil-capital

- (Malm, 2020) and its axioms of deep “spatial embeddedness” (Bridge,

- et al., 2013). I will suggest that fracturing, in its unique materiality, gives

- oil capitalists a quicker, less weighty investment mechanism to sustain

- production at a time when volatility and uncertainty deters investment

- into traditional oil. Fracking may be less ‘locked in,’ but that may make

- it more persistent.

- Finally, this approach to understanding the materiality of natural

- resource production rests alongside a somewhat distinct new materialist

- approach. Bennett’s (2010) work, emphasizing the vitality and semi-

- agency of matter, however, differs from this paper’s invocation of ma-

- teriality, which does not, in the words of Connolly (2013), investigate a

- “protean monism” of oil. New materialist ideas have influenced geog-

- raphies and ethnographies of natural resource production (Abra-

- hamsson, et al., 2015), including Barry’s (2013) work on the material

- politics of oil pipelines. While I more narrowly invoke the term mate-

- riality, this paper can give an economic contribution to Kama’s (2013,

- 2020) exploration of the scientific and political production of ‘un-

- conventional’s’ as a future resource.

3. The uncertain future of global oil markets

Two forces of uncertainty upend investment into the oil industry: the

- threat of renewable energies and the extraordinary price volatility of the

- last fifteen years. This changing situation has affected a global shift in

- upstream oil capital allotment towards shorter, flexible investments.

3.1. Renewable energy and contested demand

While renewable energy has yet to significantly encroach on oil de-

- mand, the threat that it could has impacted capital allocation. In

- particular, confusion about how quickly climate change policies will

- come, and how deeply they could cut into oil demand, places substantial

- uncertainty over the future of investment (BP, 2020).

A key expression of this is the conflicting views within the industry

- over when oil demand will peak. ExxonMobil, Chevron, and Saudi

- Aramco avoid giving direct predictions of peak demand. ExxonMobil,

- for example, argues that rising petroleum use from developing countries,

- will increase demand by 16 million barrels per day (mb/d) by 2040; they

- do not state what will happen after (ExxonMobil, 2019). In contrast,

- other companies predict the imminent end of oil growth. Jarand Rystad,

- CEO of Rystad Energy, a top oil consultancy, states peak demand could

- come before 2030 “regardless of climate issues” (Petroleum Economist,

- 2019). Shell CEO Ben van Beurden likewise stated that peak demand

- could come as early as 2025 if the Paris Accords were followed (Beur-

- den, 2017), a perspective outlined in the company’s Sky 1.5 scenario.

- That said, the company also provides a “Waves” scenario which sees oil

- production rapidly expanding until around 2050, after which it declines

- (Shell, 2021).

- Following COVID-19, this uncertainty over what the future of de-

- mand looks like has grown. Carbon Tracker (2020), a group that focuses

- on risks to financial markets posed by fossil fuels, issued a report stating

- that the world is “witnessing the decline and fall of the fossil fuel sys-

- tem,” and that with COVID-19 the profitability of and demand for oil

- will now permanently decline. Rystad (2020a) moved forward its date

- for peak oil demand to the next few years. As Goldman Sachs said, the

- virus “will likely permanently alter the energy industry and its geopol-

- itics, restrict demand as economic activity normalizes and shift the de-

- debate around climate change” (CNBC, 2020). However, many within

- energy have issued a less catastrophic assessment. In June 2020, IEA

- chief, Fatih Birol, warned, “In the absence of strong government policies,

- a sustained economic recovery and low oil prices are likely to take global

- oil demand back to where it was and beyond.” However, everything

- remains conditional. As Shell CEO Ben van Beurden stated in a call to

- investors (Bloomberg, 2020b), COVID-19 is a “ Crisis of uncertainty.” Or

- as Jeff Currie, the head of commodity research at Goldman Sachs said,

- regarding the future of oil demand, “Wait and see, we have no idea” (In-

- dependent, 2020).

- Differences in institutional perspectives on the future of oil demand

5 Marx (1867) wrote, “Labour is, first of all, a process between man and

- nature, a process by which man, through his own actions, mediates, regulate

- and controls the metabolism between himself and nature.”

6 I synonymously use extraction and production process.

7 ‘Peak oil demand’ is an ironic snub of ‘peak oil.’ Peak oil suggested that

- geologic limits would lead to a permanent decline in oil supply. Peak demand

- argues the opposite: declining demand for oil, not constraints to supply, will

- limit the industry.
partially reflect differing strategies in face of so-called “ESG Investing”8 pressure, as companies seek to attract capital, younger educated workers, and avoid the public ire (Financier, 2019; L.E.K., 2020). Firms like Shell, which has recently announced (NYT, 2021) that it is past its own, internal, ‘peak oil,’ seek to rebrand themselves as socially responsible corporate entities, with a large renewable energy focus, despite, for example, only spending three to five percent of their capital on renewables between 2018 and 2020 (IEFA, 2020).

Depending on which section of the industry you believe, or which scenario is ascribed to, radically different quantities of future oil are needed. This is seen internally within the International Energy Agency (IEA). The IEA’s flagship World Energy Outlook report provides a “Sustainable Development Scenario” (SDS) and a “New Policy Scenario” (NPS). The NPS predicts what will happen if governments enact their promised policies. The most recent forecast sees oil demand growing past 2040. The SDS, in contrast, sees oil demand permanently falling by 2021. Comparing them, a 30 mb/d gap in production emerges by 2040 (IEA, 2018). This is equivalent to 9% of current world production, roughly two and a half times Saudi Arabia’s daily output. The IEA (2020d) warns it would take trillions of dollars of investment to fill. This gap becomes more extreme in the IEA’s (2021c) latest Net Zero by 2050 plan, which calls for no new investment in fossil fuels.9 Compared to the current energy trajectory, depicted in the NPS, a roughly 80 mb/d gap emerges in expected oil demand by 2040. Similarly, BP (2020) provides contrasting outlooks to 2050. Whereas oil demand declines by 80% in their Net Zero scenario, it declines by only 10% in their business-as-usual scenario.

Eirik Warnes, the chief economist of Equinor, highlighted this divide in a talk (Warnes, 2019). “So then what is the need for new oil investments?” he asked. “I have to tell my boss, the CEO of Equinor, ‘well it depends.’ Sixty million barrels [per day] if you believe in the renewable scenario or 120 [per day] if you believe in the rivalry scenario [Equinor’s business as usual forecast].” Depending on how climate policies play out, depending on how rapidly oil demand peaks, depending on the future of global growth, radically different quantities of oil investment are required.

This uncertainty calls into question the profitability of many future projects. In the following speech by Amir Nasser, CEO of Saudi Aramco, one sees how the threat of climate change policies is seen with animosity by sections of the industry. Nasser (2018) stated, “We must challenge mistaken assumptions about the speed with which alternatives will penetrate markets. And leave people in no doubt that misplaced notions of ‘peak oil demand’ and ‘stranded resources’ are direct threats to an orderly energy transition and energy security,” continuing, “our industry needs more than 20 trillion dollars over the next quarter century to meet rising demand… This staggering amount will only come if investors are convinced that oil will be allowed to compete on a level playing field, that oil is worth so much more, and that oil is here for the foreseeable future.” Saudi Aramco views the mere discussion of peak demand as a barrier to mobilizing investments the industry requires. While renewables have not yet significantly curtailed demand, the mere threat that they could is, according to Nasser, endangering investment.

Nasser is right. The ambiguity and fear over renewable energy has already affected capital flow. One expression of this is the differing trajectory of oil stocks from the larger economy. From 2010 to 2019, the value of the S&P index increased 249.6 percent. Meanwhile, the S&P Oil and Gas Exploration and Production index fell by almost 30 percent. While tech rebounded after the March 2020 collapse, oil slumbered. Jarand Rystad (Petroleum Economist, 2019) explained, “Clearly, investors are either seeing that there will be a limit to growth [in oil], and we have to discount that into the value, or for the pure reason that they want to be compliant with the climate movement.” Sam Morgolin, director of Wolfe Research’s energy portfolio, made a similar point (CNBC, 2019): “Someone will say, ‘Oil will be used in 10 years but I don’t know about 20 or 50.’ It is just at some point in the future it will be out of the mix, and that’s a hurdle to overcome, and there are investors like that. Venture capital money isn’t going into carbon-based energy. Stocks that have really worked are the ones where there is consensus. Everyone knows online transaction counts are going higher, or streaming subscribers [are] going higher. There is no consensus on a positive direction for oil.” Stewart Glickman, an energy analyst at CFRA research, also spoke to CNBC about the changed investment climate (CNBC, 2019): “Now, alternative energy is a threat,” he said, however, “it is still not a threat, in that renewables in a really significant way are taking over for fossil fuels. But people are worried, [the industry] has lost the growth investors even if they still have the dividend investors.”

3.2. Extreme volatility

While disruptions to investment provoked by climate policies and renewable energy are a factor in the oil industry’s dilemma, they are only one aspect. The past fifteen years have also been one of the most volatile periods in oil’s history, further disrupting investment. Prior to the mid-2000’s, markets experienced two decades of relative calm. Following the OPEC crisis, oil trended below $30 a barrel, save for a brief spike caused by the Gulf War in 1990. Between 2004 and 2008, however, this system broke down. Oil spiked to a weekly average of $141 for Brent in July of 2008, only for the financial crash to send prices down to $35 a barrel by December. Within months, prices recovered. In early 2011, oil broke $100. Brent traded largely above that until 2014, when, glutted with new shale oil, and disappointed by slowing East Asian demand, the price again collapsed. Brent dropped below fifty dollars by January 2015. Oil continued to be traded in a volatile fashion, fluctuating between $30 a barrel in February 2016 up to $85 in October 2018. COVID-19 caused a new severe downturn. The West Texas Intermediate price went as low as negative $37 a barrel on April 20 when expiring contracts could not find buyers and physical glut overwhelmed the Cushing, Oklahoma terminal. At the time of writing, the price has partially recovered, with Brent reaching $70 in Spring, 2021.

Oil is an inherently volatile commodity due to the inelasticity of its supply and demand (Kemp, 2017). However, through suspending capital market forces, monopolist organizations have suppressed this volatility, allowing a functional industry (McNally, 2017). Entities such as Rockefeller’s Standard Oil, the Texas Railroad Commission, and OPEC have stopped extreme volatility throughout oil’s history, for large stretches of time, by regulating swing production, creating artificial scarcity (Yergin, 1990; Huber, 2013).

In absolute terms, adjusted for inflation, during the last fifteen years oil has reached heights not seen since the 19th century (Deutsche Bank, 2020). However, even relatively this period’s price swings surpass any other period except the very beginning of the oil industry. The average annual US min=max price spreads calculated by Rapidian Energy Group are a good gauge of year-by-year volatility. During oil’s origin in the 19th century, what they describe as “Boom Bust 1,” the average price spread was a whopping 53.3%. During the Rockefeller Era at the turn of the century, Standard Oil contains volatility to a 24.9% annual spread. The breakup of Rockefeller’s monopoly in the early 20th century leads to a second period of boom and bust, measured at 35.9% annual min=max price spread. The imposition of quotas by the Texas Railroad Commission ushered in a new era of calm with an unprecedentedly contained 3.6% price spread. The “OPEC Era,” beginning in 1974 and continuing until the mid-2000’s, had a price spread of 24.1%. But now, the recent period of volatility, since the mid-2000 shock, has a price spread of 37.1%. Rapidian Energy Group’s director, Bob McNally, a former senior Bush energy advisor, explained in a US Senate (2018) hearing why the price swings were so remarkable, “In modern times, crude oil prices don’t nearly quintuple over several years absent a war in the Middle East. And they don’t normally plunge by 60% in six months.

8 Environmental, Social, Governance.
9 Saudi Arabia has dismissed the report as a fantastic “La La Land.”
without a recession or sudden supply surge as they did in 2014.\textsuperscript{10}

This volatile price climate has, alongside the threat of renewable energies, disrupted investment into oil. At first, prices justified expensive mega projects (IEA, 2016). This can be seen in how in 2000, global yearly upstream investment stood at $160 billion, but by 2014, it had risen to $780 billion (IEA, 2016). This near five-fold increase in investments, however, only led to a fourteen percent increase in production (IEA, 2020d). This is because the cost of new oil fields increased as production moved to more expensive, less optimal conditions, and declining fields needed to be replaced with new production (IEA, 2016).

After the 2014–2015 slump, however, many of these expensive fields were no longer viable. In 2015, global upstream expenditure dropped 25 percent. In 2016, it dropped by 26 percent (IEA, 2019). Expenditure was reduced from $780 billion in 2014 to just over $400 billion in 2016 – the largest, absolute downturn in the industry (IEA, 2019). Globally, 440,000 oil workers lost their job; many more ancillary workers were indirectly impacted (Rigzone, 2017).

COVID-19 has only furthered this volatile climate. The IEA predicted there would be a 32 percent decline in upstream capital expenditure in 2020 as investment falls from $497 billion to $335 billion (IEA, 2020b). Oil and gas are expected to bear the “brunt” of a broader, unprecedented, $400 billion collapse in energy investment. However, this current price deflation seems like it could set the stage for yet another price boom. Already, by December 2020, carbon emission had surpassed its pre-Covid amount as oil use returned (IEA, 2021a). Oil demand is expected to rebound by 5.5 mb/d in 2021 after falling 8.7 mb/d in 2020 (IEA, 2021b). The IEA (2021a) notes that “Oil’s sharp rally to near $70/bbl has spurred talk of a new super-cycle and a looming supply shortfall.” While they do not see a need for immediate concern, Rystad (2020b) expects there to be a supply deficit in 2025 of 5 million bpd, causing oil prices to significantly increase as COVID-19 exacerbates a preexisting situation of underinvestment and existing oil production declines.\textsuperscript{11} While what actually transpires ‘post-Covid’ will be interlinked with economic and political developments that cannot be easily foretold – the trajectory of the global recovery, geopolitical conflict, popular opposition to the oil industry, climate policies, and the pace of technical development, to name a few – the point is that oil remains stuck in an exceptionally volatile cycle of what is a notoriously volatile commodity.

3.3. Seeking flexible oil production

The two problems of extreme volatility and the uncertain growth of renewable energy have caused a shift in oil investor appetite from long-term, large-scale production, to smaller, short-cycle production. By reducing the temporal and physical scale of the extraction process, investors and their capital reduce their exposure to the uncertain future of oil.

As an oil asset management company (SL Advisors) simply states, “Short-cycle opportunities are what every oil company needs. Consider the planners of a conventional project – a Final Investment Decision to proceed is a little less certain. Once capital is committed beyond a certain point, there’s little choice to press on and accept whatever outcome markets deliver.” The CEO of that firm (Forbes, 2018) continues the argument, “A conventional project with 10–20 years of production needs to assess how EVs might alter demand for gasoline. Improvements in battery technology and range before recharging need to be compared with greater fuel efficiency for the modern internal combustion engine. Because the development path of EVs is uncertain, it’s fair to say that conventional oil projects face even greater uncertainty than in the past.”

The growing interest in short-cycle opportunities, and the greater reluctance for investment in larger scale, long cycle production, is visible in the declining average cost and time of major conventional oil projects over the last decade. Companies have attempted to reduce their size and scope. In 2013, the average oil and gas project had a reserve of 1.1 billion barrels of oil equivalent (Wood Mackenzie, 2017).\textsuperscript{12} The average cost, furthermore, was $9 billion dollars. By 2017, the average size had shrunk to 0.5 billion barrels of oil equivalent, and the average cost to less than $3 billion dollars.

This trend towards smaller, shorter cycle oil can also be seen in the offshore oil industry. Between 2004 and 2014 the average time from investment to production in deep water was 10 years (Oil & Gas Journal, 2019). Between 2015 and 2018, the industry was able to reduce this to five years (Oil & Gas Journal, 2019), reducing exposure to price volatility. Similarly, between 2010 and 2014, new shallow water conventional projects took more than five and a half years to bring to market (IEA, 2019b). Under pressure to shorten investment cycles, the average time to market was brought down to under three years for 2017 to 2018.

Summing up these trends, the IEA (2017) wrote, “The severe downturn in oil prices since mid-2014 has both reduced the investments of the majors and forced a partial rethinking of their strategies and priorities in the wake of their changed financial conditions.” They continued, “a dual strategy is observable: more selective investments in complex projects where they are seen to have a comparative advantage and a greater share of investment in shorter-cycle projects.”

Within conventional oil production, however, it is a struggle to create short-cycle investments. Despite a substantial reduction in their complexity, new major onshore and offshore conventional fields still take an average of three to five years of development before production even starts (Deloitte, 2019). Their cost remains in the billions of dollars. They will also be produced over decades. According to a 2019 estimate, it takes twelve years for an average deepwater project to make a profit if prices are pegged to $50, and ten years under the same conditions for shallow water projects (Rystad, 2019). This is a long period under this new period of exceptional uncertainty and volatility in oil. During this span of time, the financial environment could change radically, and do so multiple times.

How can oil investors commit to such massive, capital-intensive, long-term projects if its future is so uncertain? One tactic has been to simply refurbish preexisting conventional fields, what is called a brownfield project. This, however, often just speeds up existing production at a field, as opposed to bringing new source of oil online (IEA, 2017). Another approach has been to target only the simplest, cheapest fields – even if they are long-term – but that is a strategy that is somewhat exclusive to certain geographies: cheap Gulf producers whose oil is relatively undeveloped, such as Iraq and Iran, or the absolute best offshore IOC finds, like the recent discovery in Guyana (IEA, 2020d; ExxonMobil, 2021).

4. Hydraulic fracturing’s short-cycle revolution

In this greater context of the uncertain future of oil, volatile prices, and the hunt for shorter, more flexible projects, a specific type of oil production, largely bound to the United States, has emerged: hydraulic fracturing. The unique materiality of hydraulic fracturing’s labor process allows for those oil investors who have access to it to embark on far smaller, shorter cycle investments, insulating themselves from the uncertainty of oil.

To understand how the materiality of hydraulic fracturing matters to investors, the relationship between fracking’s geology and production process should be understood.

\textsuperscript{10} See also Sherwin et al., 2018 on recent growing volatility and uncertainty in energy markets.

\textsuperscript{11} Without new investment, oil production would decline to below 20 mb/d by 2040, about a fifth of 2018 production (IEA, 2018).

\textsuperscript{12} Barrels of oil equivalent is used to convert natural gas statistics to an oil barrel equivalent.
Oil fields are like a sponge. The small holes and crevices within the rock are where the oil sits. A key aspect of all oil wells is the connection of these holes to each other, or the field’s ‘permeability.’ Permeability is the key variable in making ‘conventional’ extraction possible. The ability to extract oil from a fixed point—taking advantage of high permeability, or the fact that the oil can easily flow from one part of the rock to another (Gryphon, 2020)—is what makes a well conventional (in industry parlance). Imagine an office building filled with people. Depending on how many doors there are between the various rooms, and stairs to the various floors, people will have an easier or harder time moving around the building. This is the equivalent of permeability. In fields with high permeability, the pumping of oil from one part of the field can suck oil from another part.

In contrast, tight shale fields have extremely low permeability (Government of Canada, 2016). Oil cannot easily travel through tighter rock. To extract oil, the rock must be fractured, artificially creating permeability. To do this, producers inject pressurized water into different segments of the field, creating small fractures in the rock that allow the oil to flow. Alongside a mix of chemicals, the fracturing fluid contains particles of sand as “propant.” The particles prop up the fractured holes, elongating the time before permeability collapses. In most fractured fields, very little of the overall oil originally in place can be extracted, due to the limited and temporary character of the artificially produced permeability: for example, an estimate from the Canadian Bakken found that wells only extracted 3 percent of the actual oil in place (CSUR).

Several key features result from investors’ attempts to profitably extract oil through the application of the hydraulic fracturing process to these geologic formations of oil-bearing low-permeability rock. First, the materiality of fracking makes its scale radically smaller than conventional production. Fracking is relatively small scale because oil will only flow from where the reservoir rock was fractured. This means that the size of the field is limited by the extent of the fracturing, extracting, as mentioned only a small portion of the oil, tightly locked-in the rock. Shale fields are thus relatively small operations, targeting a tiny portion of oil compared to new conventional plays. Their costs are likewise miniature. The result is a granular type of production. By granular I mean fracking requires many individual, small grains of investment, to compare in production and cost to one single-massive, new, conventional field. The average cost in 2015 of wells in all major US shale plays was below $7 million dollars (EIA, 2016). In the best parts of the Permian basin it was lower than $6 million dollars, from start to finish, per well (EIA, 2016). In contrast, the average cost of a major conventional project was just under $5 billion in 2015, a thousand times more expensive (Forbes, 2019). While costs for both have risen slightly over the years, they remain orders of magnitude away from each other. This, however, does not mean that hydraulic fracturing is less expensive per barrel, as offshore conventional wells target much larger quantities of oil. An offshore platform will also have several wells attached to it, but are, of necessity, a part of one bulk investment. Thus while fracking may be expensive, per barrel, the scale of fracking investment is radically smaller. This is one reason why fracking could be developed by smaller US companies without the cash troves of the IOCs.

A second feature is that fracking produces its oil more quickly than a conventional field. Because hydraulic fracturing relies on the artificial fracturing and pressurization of a well, the flow rate starts high and then drops steeply. All oil wells start near their highest rate of production and then decline. However, for hydraulic fracturing, that decline is a steep drop off rather than a gradual decrease. Conventional wells can pump for a decade or more at high volumes, depending on the reservoir, losing an average of 6 percent of its production each year (Kleinberg et al., 2018). But fracking sees a roughly 80 percent fall in daily production within the first two years (Land, 2014). A model from the US Energy Information Agency (EIA, 2020) based on a well in the Bakken shows production starting at just over 800 barrels per day in the first month. By the end of the second year of production it drops to less than 100 barrels per day. Afterwards, production continues to drop, declining almost 25 percent per year. The well may produce a small trickle for ten or twenty years, but the vast majority of oil will be produced within the first two years (Kleinberg et al., 2018). A commercially meaningful quantity of oil can still be produced during this long-tail, as it may continue ten or twenty years with no new investment, but it is much smaller than the opening months.

Third, fracking’s small scale of production, its granularity, results in a shorter time from investment to first production, as a smaller project requires less effort to get going. According to Deloitte (2019), “Spud-to-well completion takes two to four months, compared with offshore projects that take two to five years to produce first oil.” That is, roughly, a twelve-fold difference in time to begin production. US shale consulting firms frequently sell their services to independent frackers with the promise of reducing both “well cost and cycle time,” that is the speed from extraction to production (Wood Mackenzie, 2017). One can get a felt sense for this contrast in the scale of the initial and most critical part of the labor process by comparing two time-lapses, one the fracking of a well in the Eagle Ford basin in Texas by Marathon Oil (2012) and ExxonMobil’s Hebron (HFI AW, 2015) field off the coast of Newfoundland. While the shale is drilled and fracked within weeks at a small site, the offshore well is a gargantuan assemblage of industry and labor, as a massive offshore platform is constructed onshore, before being towed to site, with drilling not even started.

A fourth additional point is that due to the drilling and fracturing process being two short distinct activities within the overall labor process, it is easier to drill wells but leave them unfracked, waiting for better prices, than it is to start conventional wells without exploiting them. These are known as “drilled but uncompleted wells,” or DUCs. During downturns, such as 2020, frackers abandon fields that have been drilled but not fracked, leaving the relatively expensive fracturing process until later when prices are right (Rystad, 2020).

Overall, this granular, short cycle labor process allows for a much shorter-term, flexible investment. As Rystad’s head of upstream research, Epsen Erlengsen, notes (Rigzone, 2019), “Tight oil is a short cycle investment with a relatively brief lead time from the sanctioning of new wells to the start of production. This gives E&P companies the flexibility to adapt to market conditions and easily change activity levels. In the ever-changing oil price environment, this implies tight oil investment has less uncertainty compared to offshore.” Or, as Fatih Birol, director of the IEA, told the US legislature (U.S. Senate, 2019), “It is the massive growing volumes of US shale and the flexibility to quickly contribute to global markets. After a decades-long oil industry shift towards larger projects with longer lead times, US shale offered new supply from projects with short lead times that could be quickly scaled

13 Innovations in horizontal drilling over the last thirty years have been crucial for making hydraulic fracturing profitable. While fracking itself dates back at least to the 1940’s, horizontal drilling methods allowed the application of fracturing to larger quantities of oil per well (even if, overall, it remains orders of magnitude smaller than an average new conventional well).

14 Conventional fields from the heyday of the 20th century oil boom, such as the Texas gusher Spindletop, or Saudi Arabia’s Ghawar, are much simpler operations than today’s new conventional fields. New offshore production requires massive capital investment for platforms, pipelines, etc. that has been described as akin to a space mission (Aleklett, 2012). While the industry continues to use the term ‘conventional’ to describe these fields’ high permeability, socially and colloquially speaking, there is nothing conventional about new conventional oil.

15 Unlike shale, the major capital costs involved with an offshore platform prevent individual wells from being invested piecemeal.

16 By productive investment I mean a producer of oil investing in an oil production project as opposed to a financier investing in an oil production company.
up or down, providing much needed flexibility.” Flexibility and reducing exposure to uncertainty are shale’s key aspects. As an oil investment manager (SI Advisor) writes, “The real revolution of shale is its short capital cycle; numerous wells are drilled cheaply, with fast but sharply declining production. Capital invested is returned with a year or two and capital cycle; numerous wells are drilled cheaply, with fast but sharply declining production. Capital invested is returned with a year or two and risk can be hedged.” In contrast, “conventional projects require huge upfront commitments with long payback times and consequently uncertain economics.” Or, as Deloitte (2019) states, “This shorter investment cycle, coupled with high production decline rates, makes production from shale highly responsive to short-term price fluctuations, allowing it to protect against ‘uncertainty’ and ‘rising volatility.’ Summing up, because fracking is a quick, granular production process, and because its oil is likewise extracted so quickly, it offers a host of short-cycle, flexible financial benefits to the company.

The sustained attractiveness of this short-cycle oil is demonstrated in fracking’s recovery after the 2014–2015 price crash. Before the crash, fracking capex (capital expenditure) had already grown from around $70 billion in 2010 to $160 billion in 2014, more than doubling in four years (Rystad Energy UCube, 2019). From 2000 to 2009, tight oil had only made up an average of 4 percent of yearly global oil investments but, between 2010 and 2015, it made up 17 percent (IEA, 2019). When the price crash hit, some thought that hydraulic fracturing would be ruined. Fortune (2016) warned, “The shale revolution is danger,” as prices fell below $100, closer to $50. At first, this seemed correct. Shale shrank to 13 percent of global capex investments in 2016 while new drilling slowed and investment in the industry as a whole declined (IEA, 2019). But by 2017, the trend reversed. Shale grew to 21 percent of global investment that year and then 26 percent in 2018, even in the new, low-price environment (IEA, 2019). The IEA (2018) stated, “Global upstream capital expenditure (capex) for oil and gas in 2017 was largely unchanged from the previous year at USD 440 billion (bn) after a 50% increase in spending on US shale was largely offset by declines in investment elsewhere.” In 2018, the United States made up 98 percent of all global oil growth as fracking added 2.2 mb/d of production (Forbes, 2019). To the extent that new oil was being developed in any country, beyond replacing declining fields, it was hydraulic fracturing. Put simply, fracking has an ability to both rapidly contract and expand. This may be important for understanding its current trajectory.

While fracking’s development has been led by smaller firms, major American oil companies have also shifted toward the production method, further speaking to the way that it has been used as a salve for an uncertain epoch. The majors made this transition for the same reason that investment in the industry, more broadly, had been shifting towards flexibility and short-cycle production: to protect against uncertainty. Shale went from being two percent of oil investments for major international oil companies in 2009 to an estimated 21 percent in 2019 (IEA, 2019). Chevron began devoting one third of its capex to short cycle production in 2017, primarily in the Permian and Bakken shale fields (His Markit, 2020). As Exxon’s CEO recently told Reuters (2019), its massive 1.6 million acreage in the Permian would change “the way that game is played,” probably ruining many of their smaller, less financially resourced, competitors. Or as Chevron CEO Mark Wirth told oil historian Daniel Yergin in a video conference (CERAWeek, 2020), presenting the transition to the oil industry’s favor, “We have intentionally reshaped from a [company] that a decade ago was heavily dependent on long cycle very expensive projects, to one now that is dominated by shorter cycle projects where you do have flexibility.”

In summary, the materiality of hydraulic fracturing’s labor process – its mediation of the oil in the reservoir and the social forces, above all capital, mobilizing it above ground – is notably different from conventional production. These differences result in a granular, quick, scale of investment, both in terms of money and time (see Fig. 1). This distinct mode of extraction is uniquely suited to the turmoil, uncertainty, and volatility that has emerged. Fracking, in this sense, can be seen as a quick fix, the frenzied spawn of an industry facing existential dread.

5. Fracking’s future

COVID-19 severely impacted fracking. The IEA (2020b) states, “Some of the most dramatic cuts in the oil and gas sector – in many cases above 50% – have been among highly leveraged shale players in the United States, for whom the outlook is now bleak.” Many now suggest that this method of extraction is permanently over (McClean, 2020): “The Shale Bubble is Bursting. Let it,” writes one commentator (Krill, 2020). Their and Huber (2020) note the downturn but see it as an opportunity not a guarantee of change. A researcher at TS Lombard suggests (Reuters, 2020) there will be a differentiation among producers with small players folding and the larger firms taking over.

It is important, also, not to overstate the “bust.” US production remains extraordinarily high, at 11 mb/d, with 7 million coming from fracking in March 2021 (EIA, 2021). US fracking would remain the third largest oil producer if it were its own country. There were 226 fracking crews operating as of May 29th, 2021, in the US, up from the low of 45 last year, but not recovered to the range of 300-350 crews operating before the pandemic (AOG, 2021).

Fracking’s short, granular qualities, suggests its tendency is to recur as volatility and uncertainty in oil persists. The downturn may therefore not be so much a death sentence but rather a stage in an elastic process. Chevron CEO Mark Wirth (CERAWeek, 2020) was, for example, asked how fracking impacted Chevrons during the pandemic. He said, “I think [shale] has served us well as we’ve run into this crisis.” Continuing, “The intent wasn’t to bring [investment] levels down unless we had to, but we wanted to have the ability to do that in the event that we needed to, and I think it has served us well as we’ve run into this crisis.” As he stated, “The flexibility of it is absolutely something we’ve been conscious of it in building it into our capital plans.” This is the key point. For more financially stable players, like Chevron, fracking’s nimble qualities have been a benefit during this extraordinary time of the global pandemic.

Even more, the compounding uncertainty over the future of oil demand, due to COVID-19, the global economy, and above all the renewable energy transition, make oil companies hesitant to invest in long-term capital-intensive projects. As Amy Jaffe, a senior energy fellow at the Council of Foreign Relations, explained (WSJ, 2020), “The crux of the matter is that it’s going to be difficult to restore vertical [conventional] production in a lot of places in the world, but the shale will be easier to restore, and that gives it an edge.” This is why the IEA (2020b) says that it is “too soon to write off shale as a whole.” In fact, they predict (IEA, 2020c) that the US will remain the largest oil producer through 2040, due to fracking taking in $85 billion a year of investment.

Imbedded here is an unsavory conclusion: fracking seems – at least when viewed in this strictly economic manner – to benefit from the renewable energy transition. The more renewable energy encroaches, the more climate policies are successful, and the more doubt is cast as to the future of oil, the less incentive there is to invest in oil’s long-term. A fracked well is a quick fix, focused on the initial two to three years. A new conventional operation is a decades-long endeavor. Assuming fracking is not directly banned or prevented from operating, capital may become more attracted to this particular labor process because it allows investors to avoid the long-term future of oil.18

The irony is worth pausing on. Hydraulic fracturing is a particularly environmentally damaging form of extraction, requiring huge quantities of water and sand, releasing toxic chemicals into the groundwater and air, and fragmenting and disturbing landscapes (Kreipl and Kreipl, 2017; 2018).
Gallegos, 2015; Lave & Lutz, 2014). Yet capitalist logic would seem to endorse this form of extraction as a prudent investment during a market-led renewable transition. In this sense, I suggest viewing fracking as a particular extractive strategy, pursued by certain sections of the industry with access to US fields, to preserve fossil-capital as a period of fraught and contested transition begins (Huber, 2009; Malm, 2016).

That said there is nothing predetermined about fracking’s future. While the unique qualities of fracking identified in this paper may allow it to flexibly rebound, riding the waves of uncertainty and volatility, its actual development in the US will also be bound up with an array of political and economic conditions much broader than the focus of this paper. For example, fracking has been supported by government subsidization and the absent, or patchwork character of regulations (Counts and Block, 2016; Neville, et al., 2017; Baka et al., 2020, 2018). How will this regulatory climate change this coming decade? While considerable popular pressure exists to regulate or stop its development (Ladd, 2018), fracking has benefited from pre-existing oil and gas infrastructure, a large community of advanced oil and gas talent and technology, a massive resource base, little to no regulations, oil and gas subsidies, geopolitical desires for ‘energy independence,’ and a unique relationship to massive lines of credit (McClean, 2018). Experimentation in fracking outside of the United States has mainly been in gas production because gas is harder to transport, and thus its prices are more regional, less subject to competition. Because oil fracking’s development elsewhere would be more expensive than American fracking, which has developed in these special conditions for a decade, it would take sustained high prices to encourage a non-American oil fracking boom. For example, in China, the oil resource base is comparably massive in scope to the US, and little to no environmental regulation prohibits the state-owned oil companies, fracking remains almost exclusively about gas.

6. Conclusion

Hydraulic fracturing of tight oil formations is materially different from conventional oil production. These differences in the materiality of its labor process allow it to be more nimble, flexible, and granular as an investment for upstream oil capitalists. In the face of growing uncertainty over the future of oil, caused by volatile markets and the encroachment of renewable energy, fracking’s flexible production process has attracted capital. While oil fracking in the US is propelled by other factors – cheap credit and the US political environment chief among them – these unique qualities of its production process have likewise played an important role.

Though some may understandably celebrate the disruptions they see in the oil industry, fracking is a tool oil capitalists in North America are using to adapt to this challenging environment. Shale has not solved its conundrum – it has not ended these cycles of volatility nor guaranteed oil’s future; but it gives sections of the industry a means to ride the waves. In this context, scholars and activists should question those who suggest that fracking or, for that matter, oil will melt away in face of recent oil market tumult. There is no automatic transition to renewables underway. Political action is required to solve the climate emergency.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

<table>
<thead>
<tr>
<th></th>
<th>Conventional</th>
<th>Hydraulic Fracturing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Investment per project*</td>
<td>$5 billion</td>
<td>$4.9-8.3 million</td>
</tr>
<tr>
<td>Time until first production**</td>
<td>2-5 years</td>
<td>2-4 months</td>
</tr>
<tr>
<td>Production decline after first two years***</td>
<td>12%</td>
<td>80%</td>
</tr>
<tr>
<td>Estimated time until first profit****</td>
<td>10-12 years</td>
<td>2-4 years</td>
</tr>
</tbody>
</table>

Fig. 1. Hydraulic fracturing and conventional investment scales of extraction compared, by author. * Hydraulic fracturing data from EIA (2016), conventional from Wood Mackenzie as quoted in Forbes (2019). ** Deloitte, 2019 *** Production drop from original peak production flow, estimates from EIA and Rystad. ****Estimate from Rystad (2019) assuming stable price of $50 per barrel (Brent). Conventional is for offshore deepwater and offshore shelf.
Acknowledgements

I would like to extend my thanks to the three anonymous reviewers who helped me significantly improve the quality of this paper. I would also like to thank Michael Watts, Nathan Sayre, Jan de Vries, Rakesh Bhandari, Caroline Tracey, Emelie Javelind, and Zander Eckhouse for their respective support, help and guidance in its completion. For any errors and shortcomings of the piece I take full responsibility. Several colleagues in the Watts writing group and the Sayre lab at UC Berkeley were also helpful in its development.

References


Further reading


Further reading


Further reading


Further reading


Further reading
