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Energy Transition, Uncertainty, and the Implications of Change in the Risk Preferences of Fossil Fuels Investors

Abstract

Energy transition risk is often viewed as a long-term risk, the impacts of which will not be felt for decades to come. However, this view is an imprecise presentation of reality. This is because although completion of transition might take decades, the increased uncertainty around the transition impacts the energy markets on a much shorter time scale than the transition itself. This article presents the results of a survey of institutional investors on hurdle rates for new energy projects and compares it with information available in the public domain about discount rates on completed projects. The survey shows that uncertainties associated with energy transition have already started to alter the risk preferences of investors in fossil fuel projects. Investors are demanding a much higher hurdle rate in order to invest in long cycle oil and coal projects. We contend that such changes in risk preferences will have several key implications for fossil fuel markets. First, the payback period of discounted investment costs is extended dis-incentivising long cycle projects, therefore concentrating upstream investment around short-term projects with shorter payback periods. Second, it impacts asset valuation of fossil fuel companies with consequences for firms' cash flows and asset payoffs. Third, it encourages the oil and gas companies to adopt a low risk operation model, focus on the harvesting phase of their oil assets, and move away from exploration, appraisal and development. Fourth, it could affect the volume of available supplies if there is not enough investment into the sector with potential consequences on prices depending on demand projections. Fifth, it could affect the long-term price of oil when energy markets start to price in transition related risks. Sixth, the energy transition process could be accelerated as higher long-term oil prices improve the economics of alternative resources.

1. Introduction

Energy transition is inherently a risky process. Generally market participants will be exposed to four types of risk during the transition (i) demand and technology risks (ii) market price risks (iii) policy risks and (iv) other risks. Demand and technology risks are related to the entire set of parameters that affect the volume of the goods and services that are traded annually (e.g. electric vehicles vs. internal combustion engine (ICE) vehicles) and the technology or the fuel that is associated with them (e.g. renewable kWh versus Coal kWh). Market price risk pertains to factors that impact the ways in which non-policy related prices of goods and services evolve. This includes commodities themselves (for example oil and gas prices or the price of carbon emissions) and technology inputs into the production process (for instance the price of batteries). Policy risk is related to all types of policy related incentives (e.g., subsidies), costs (e.g., tax), performance standards (e.g. fuel efficiency standards), production

standards (e.g., electric vehicle sale mandates) and direct regulation (e.g., ban on specific technologies such as ICE cars or phasing out of certain technologies such as coal). Other risks include litigation costs, reputational issues and any other factors that affect the business model or the value of companies' assets such as the rise of incidences as a result of extreme climate.

Energy transition risks have often been considered as a long-term issue. This view is misleading, as there is a difference between the timescale within which the transition is completed and the timescale within which the manifestation of its effects on energy markets are felt. Investors adjust their perception of market risk much faster than the time scale required for transition to be completed. The risk of energy transition manifests itself in various forms, including investment and operation decisions by market participants and/or adjustment in the value of companies' asset, amongst others.

This paper investigates the questions of how the energy transition has impacted the risk preferences of investors and the implications of the change in risk preferences for fossil fuel markets. Although energy transition risks are often attributed to the impacts of realigning the economic system with low carbon solutions through market, technology, regulation, and policies, in practice, it is difficult to quantify some of these risks. For example, cash flow impacts from non-linear risks, such as new regulations or a technological disruption are hard to model due to uncertainty around their timing and magnitude. However, all information about the level of risk a particular company is exposed to can usually be summarised in a single parameter, namely, the discount rate. Investors adjust their beliefs about the risk level by adjusting the level of the discount rate¹.

Our survey² of investors shows that concerns over energy transition have already started to alter the risk preferences of investors in fossil fuel projects. Investors are demanding a higher hurdle rate in order to invest in long cycle oil and coal projects. In the past year, some of the largest international oil companies (the Majors) have raised medium-term debt at low single digit interest rates. Yet, according to the survey, the hurdle rate for new, international oil and gas projects is being stated at closer to around 20 per cent by investors— an apparent and perplexing mismatch. Understanding this paradox is well worth studying, because doubling discount rates would approximately halve valuations across the sector. Also an increase in hurdle rates dis-incentivises investment in long cycle projects, concentrates upstream investment around short term projects with shorter payback periods, causes the oil and gas companies to focus more on the harvesting phases of oil and gas fields and adopt low risk operation models away from Exploration & Appraisal (E&A) and Development; it also affects the long term oil price which could speed up the energy transition process.

2. Energy transition and investment in hydrocarbons: change in risk preference

Over the last few years a plethora of studies have been dedicated to the question of the speed of energy transition to a low carbon era (see for example, Fouquet, 2016; Sovacool, 2016; Sovacool and Geels, 2016, Fattouh et al., 2018). While the speed of transition is a legitimate question, there is another dimension of energy sector transition that is left almost unaddressed: how the transition is affecting the risk perception of market participants. This is a very critical question because even if all forecast and analysis about the speed of transition (and consequently peak oil demand) turn out to be wrong, the mere perception of increased risk in the future will alter the behaviour of market participants in the present. In other words, the belief of market participants' changes faster than market fundamentals themselves, leading eventually to a market correction.

This assertion is drawn from the findings of our survey of institutional investors. With the top forty public oil and gas companies worldwide due to generate an all-time record – \$200bn – free cash flow this year

¹ Although discount rate is not fully reflective of the transition related risks (as it also captures other risks that the firm is exposed to) it is a way for companies to evaluate their investment options and put a value on their future cash flow.

² The survey of institutional investors was conducted from July to October of 2018. There were 26 participants in the survey. These included investors based in the United States and in Europe, from 'long only' asset managers, hedge funds and private equity investors. Each interview focused on the hurdle rates that were seen to be desirable for different types of energy investment.

(West, 2018), we asked whether shareholders would prefer greater distributions or greater reinvestment with the growing surplus of cash. Specifically, we asked:

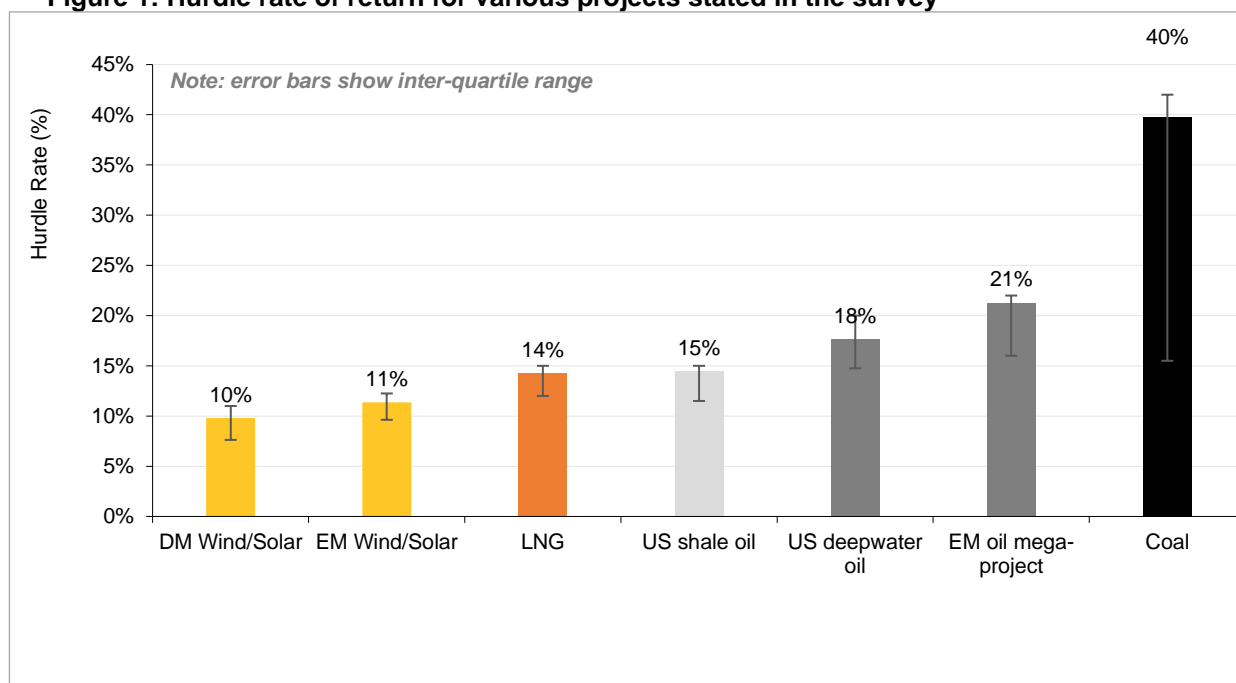
“What base case Internal Rates of Return (IRR), or hurdle rate, must a new energy project generate, for you to prefer reinvestment in that project, rather than further growth in dividends and buybacks?”

The results are shown in Figure 1. The hurdle rates stated are, on average, 10-11 per cent for solar and wind, 14 per cent for LNG, 15 per cent for shale oil, 18 per cent for deepwater oil, 21 per cent for large projects outside of the safest geographies and 40 per cent for new coal mines.

These results are compared with benchmark hurdle rates for past and current projects that have been compiled using information available in the public domain (see Figure 2.). It can be seen that projects in the last few years, on average, have had a hurdle rate of 9-11 per cent for wind and solar, 12 per cent for LNG, around 10 per cent for shale oil, 15 per cent for US deep-water oil, 13 per cent for mega projects and around 16 per cent for coal mine investment.

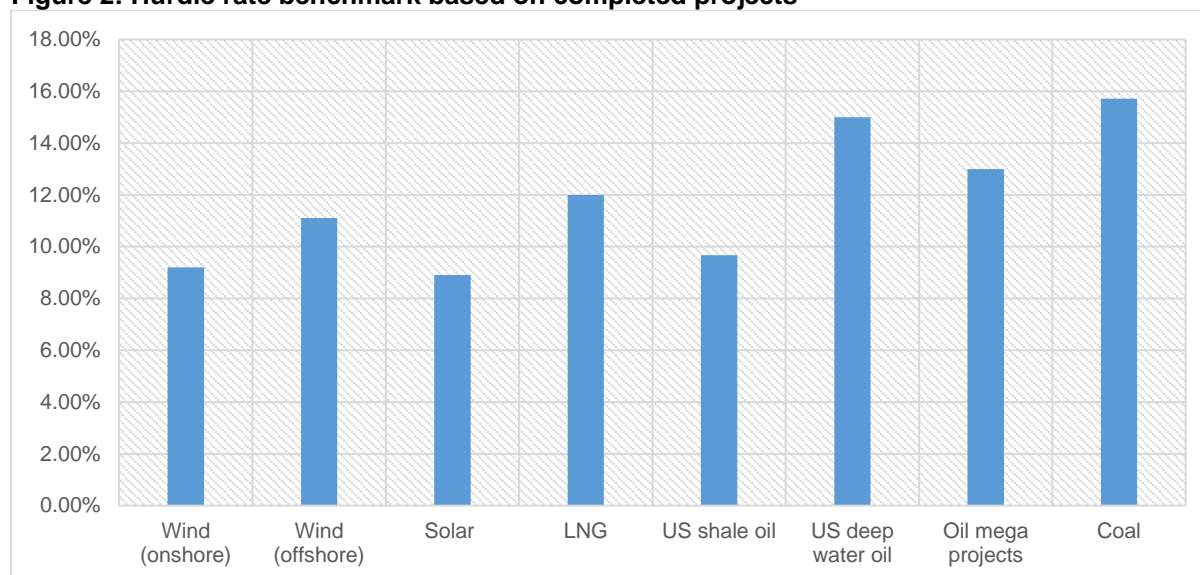
The comparison between Figures 1 and 2 reveals an interesting picture about the change in investment uncertainty around energy projects over the last few years. It shows that the hurdle rates for wind and solar, and LNG projects, have remained relatively stable. However, there has been a significant increase in the minimum required level of return for other fossil fuel projects, especially deep-water oil, long cycle mega oil projects, and new coal. If this is a true representation of the change in risk perception, then the entire landscape of fossil fuel investment needs to be reconsidered.

Figure 1: Hurdle rate of return for various projects stated in the survey



Source: Authors

Figure 2: Hurdle rate benchmark based on completed projects



Source: compiled by authors from NERA economic consulting (2015), Mercer Capital (2018), Wood Mackenzie (2018), Al-Shehhi (2014), Bora et al. (2015) and experts' informal interview

The main reason for the stability of the risk profile in wind and solar projects is that these resources are widely shielded from market uncertainties through government support schemes. At the same time, the costs of these technologies have been on a descending trajectory and this creates an expectation of better economics in the future. The LNG market has also been developing fast over the last few years and investors are more receptive to natural gas due to its low carbon content and its ability to complement intermittent renewables.

The leading reason for higher hurdle rates in long cycle oil and coal projects is the growing concern of investors surrounding energy transition. In turn, this is requiring companies to justify new capital investments to the market. For example, BP has disclosed a 15 per cent hurdle rate (at \$60/bbl oil) for new greenfield investments (BP, 2018). ExxonMobil has prioritised the most counter-cyclical investment, hence its cash flow should grow 3.5 per cent pa to 2025, against a sector average of 0.6 per cent, yet many commentators have voiced discontent over this strategy, preferring shorter-term buybacks instead (West, 2018b).

Regarding coal, the situation is even worse when it comes to risk perception. Several investors in our survey said no return would be sufficient to make them comfortable investing in coal projects, given long-run fears over climate change legislation³. Specifically, one investor asked "What return do you require for something that is likely to be abolished at any point?" going on to cite how Germany recently denied RWE permission to keep its Hambach mine in full operation (Reuters, 2018). Another investor said he required high returns to compensate for "when end of life is – not in terms of the ability to produce [fossil fuel assets] – but when the government shuts them all down".

These comments add to the 800 institutions, with \$6trn in assets, under management that have promised to 'divest' from fossil fuels (West, 2018; gofossilfree.org, 2018). These comments also tally with our observations of the industry in recent years. Coal miner New Hope recently noted that "Australian mines are at their capacity and it's very difficult to get approvals for any new coal mines" (Reuters, 2018b). California democrats recently said they want to "ban all fossil fuels from the electrical grid" at some point after 2030 (Wall Street Journal, 2018). And in 3Q18, New York regulators denied

³ Another investor said the same about deep-water oil.

an air permit for a newly built 680MW gas-fired power plant in the State of New York, as climate activists criticised its carbon dioxide emissions and gas use from fracking (APPA, 2018).

While such a change in risk environment due to energy transition may not be surprising, the implications of said change are highly significant. This is because, to date, transition has been seen as only possibly having long-term effects. This, along with the uncertainty about climate change and emissions abatement policies, may lead to an underestimation of the problem and its effect on growth prospects, firms' cash flows, and asset payoffs. In the next section we discuss some of the implications of the change in risk preferences of investors during the transition.

3. Implications of the change in risk preferences of investors during the transition

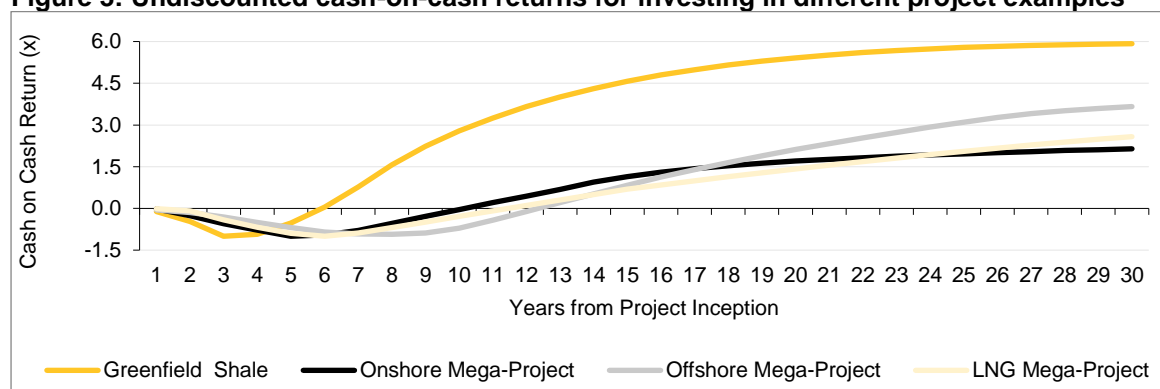
3.1 Implications for investment in long life projects and the value of firms' assets

Investment in irreversible projects requires a good degree of assurance for investors. No investor can be expected to commit capital, if there is a growing risk of losing it. The risk is particularly acute for long-cycle projects in the oil and gas industry, as illustrated in Figure 3, which plots the undiscounted cash-on-cash returns for investing in different project examples.

In order to see how uncertainty affects the appetite of investors consider the three long-life projects shown in Figure 3 – one onshore mega-project, one offshore mega-project and one LNG mega-project. These are perfectly good investments under base case assumptions, exceeding 10 per cent hurdle rates at \$45/bbl oil, and generating Internal Rate of Return (IRR) of around 15-20 per cent at \$65/bbl long-term oil prices. Yet it takes 10-12 years before these projects have repaid their undiscounted upfront investment costs. It takes 20 years before they have repaid those investment costs, fully discounted. Thus an investor is implicitly being asked to look out to 2028-38 and decide whether these projects are rational investments. Over the 2028-38 timeframe, uncertainty is very high. And uncertainty leads to higher capital costs and investment paralysis. In other words, the first victims of changes in the risk perception of investors during energy transition are long life oil and coal projects.

In a similar manner to investment, asset valuation is also important in relation to energy transition risk. This is because oil and gas companies constitute a major portion of the nonfinancial corporate sector with a total global market capitalisation in the order of several trillion dollars. Changes in risk (and consequently discount factors) will lead to reassessment of the value of these firms and their future profits. This could have a huge impact on their market capitalisation, demand, creditworthiness, and the value of their assets. This is especially problematic because oil and gas companies are heavily debt financed and asset revaluation has implications for the stability of financial markets. While a discussion about contagion effects is outside the scope of this article, it shows the impacts are not confined to energy markets (which is the focus of this paper).

Figure 3: Undiscounted cash-on-cash returns for investing in different project examples

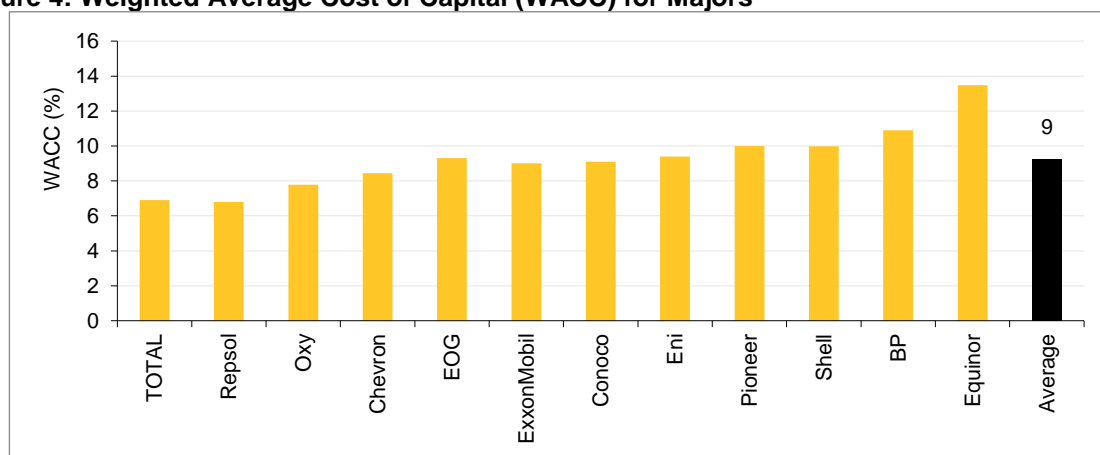


Source of data: Redburn. Note: Cash on cash returns are calculated as the 'averages' of over twenty projects collated according to project type

3.2 Implications for Net Present Value (NPV)-neutral prices and long term prices

Changes in risk will impact the price of oil at which NPV-neutral levels can be achieved. To date it has been common to assume the cost of capital to be around 10 per cent for NPV computation (West, 2016). This assumption is based on estimation of average Weighted Average Cost of Capital (WACC) across Oil Majors. Under US Security and Exchange Commission (SEC) disclosures, Oil Majors report the NPV of their reserves, each year, using a 10 per cent discount rate. Bloomberg’s average WACC for a dozen major oil and gas companies is currently calculated at around 9 per cent (Figure 4), using the Capital Asset Pricing Model (CAPM). At a 10 per cent hurdle rate, the average project requires \$40/bbl oil to be NPV neutral.

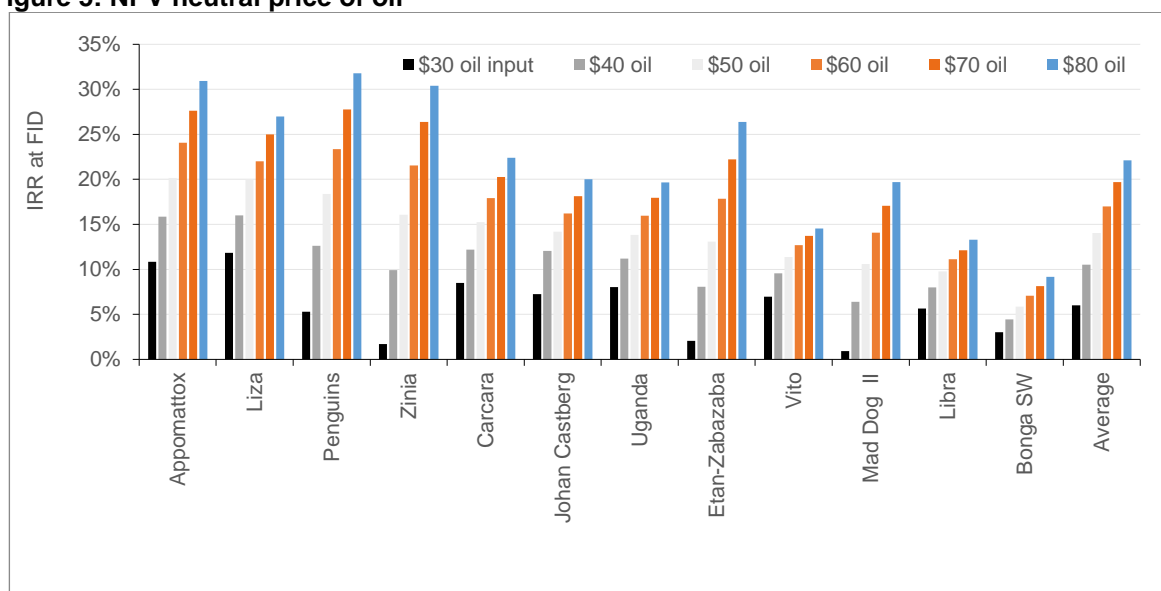
Figure 4: Weighted Average Cost of Capital (WACC) for Majors



Source of data: Tabulated from Bloomberg

However, the hurdle return has changed and is now being stated at closer to 20 per cent by investors for new international oil and gas projects. This is despite the fact that some Majors, in recent years, have raised medium-term debt at single digit interest rates pa. This means that the NPV neutral price of oil is also closer to \$70/bbl, not \$40/bbl. Add in exploration costs and corporate overheads and the full-cycle breakeven rises above \$80/bbl. This can be seen in Figure 5, which draws on modelling of forthcoming greenfield projects.

Figure 5: NPV neutral price of oil



Source of data: Redburn

A question that arises here is: what is the relationship between the aforementioned NPV-neutral prices and the long run price of oil? One way to think about long-run commodity prices is by analogy to 'marginal cost' of supply for a given level of demand. This is conceptualised as the incentive price for the world's marginal sources of supply growth to deliver new production volumes to the market, while covering their own costs of capital. The equilibrium price (which is a function of demand, hurdle rate and available supply) provides a framework to discuss long-term oil prices. However, it should be noted this approach is quite simplistic and assumes that oil markets are efficient, an assumption that can be challenged. Also, at times, OPEC members restrict supply to support higher prices, which is needed for the functioning of their economies and their welfare systems (see for instance Dale and Fattouh, 2018).

To discuss trajectories for long run oil prices, given the increase in hurdle rates we consider two scenarios. In the first scenario we assume demand for oil remains robust. With strong global economic growth over the next few years (3.9 per cent as per forecast of IMF), the IEA (2018a) forecast oil demand to grow by 2 mb/d and reach 104.7 mb/d in 2023, up 6.9 mb/d from 2018. While the IEA sees no peak oil demand in sight, it expects the pace of growth to slow to 1 mb/d by 2023 after expanding by 1.4 mb/d in 2018 (mainly as a result of the substitution of oil by other energy sources in various countries). A robust demand growth will necessitate a strong supply response. However, upstream investment has not still recovered from the 2014-2016 drop (it was flat in 2017 and there was only a modest rise in 2018, with a focus on light tight oil in the USA). Adding to this the natural production decline from existing matures fields, which is estimated to be 3 mb/d of supply each year, there is a potential supply gap. The IEA (2018b) estimates a supply gap of 26 mb/d in 2025 will exist even under its Sustainable Development Scenario (2 degree). Under its New Policy Scenario (2.7 degree), the supply gap is estimated to be 35mb/d⁴.

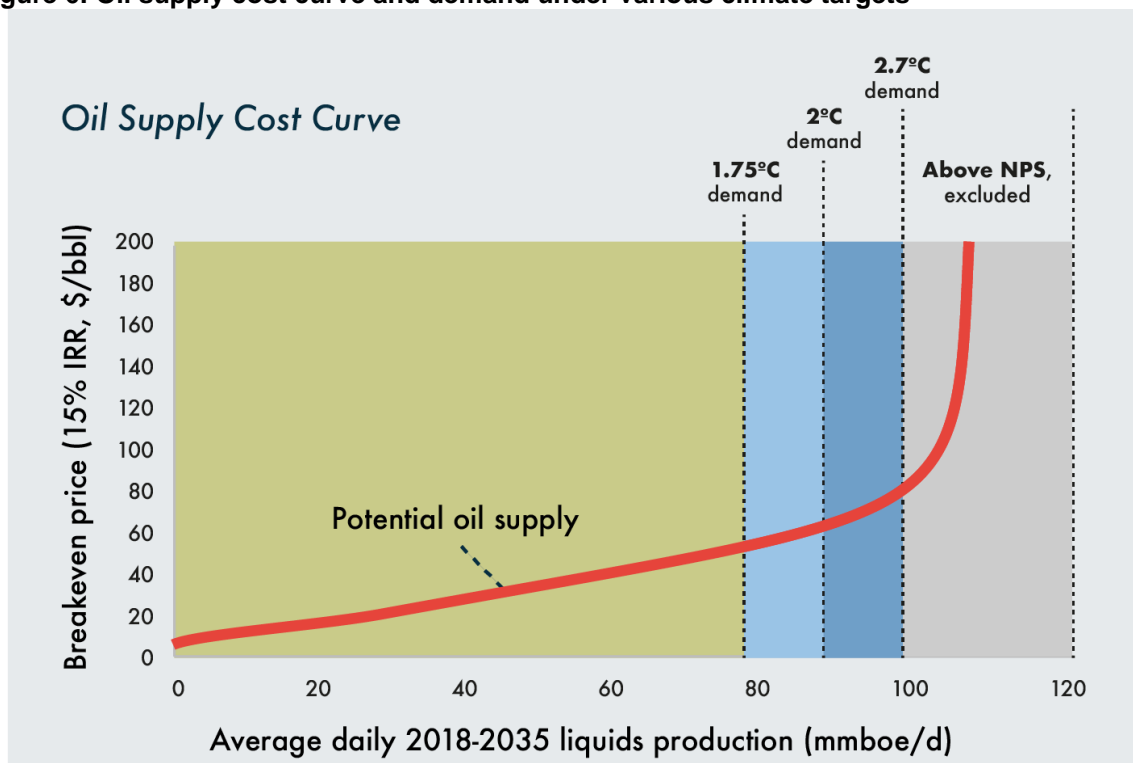
The possibility of a supply gap due to lack of investment, along with the current demand trajectory, means that the long-term price for oil can be higher than previous estimations if the market starts to price in transition related risks. In practice we do not know exactly how much the hydrocarbon supply gap would be or how much investment will be needed to fill the gap, (as it depends on future oil demand in a carbon constrained world and project approval on conventional new investment) and the size of the gap, which is uncertain, is a key determinant of incentive price. The key point, however, is that whatever size the gap, and the consequent appropriate incentive price is, oil price may need to be sustained above the incentive price for some time in order to progress new long-term projects. *So it is possible that higher hurdle rates could stoke long-run oil prices, with implications for long-term supply and demand.*

The alternative scenario is that demand growth declines and falls much sooner than expected. This is a less likely scenario given current trends, but it is not impossible and could be the result of more stringent emission policies in future and/or the extension of government decarbonisation efforts beyond the power sector and into the transport sector; being further boosted by the declining cost of electric vehicles (EVs) and improvements in battery technologies. *If emission policies lead to a fall in demand at the same pace as, or faster than, production decline from existing fields, then, potentially there would be no hydrocarbon gap and thus this risk would not have a material effect on the long term price of oil.* For illustration purposes we use Carbon Tracker global oil supply cost curve under various outcomes for global warming and assume a 15 per cent hurdle rate of return (see Figure 6). Clearly, there is a huge difference between oil demand in 1.75 degree versus 2.7 degree under the IEA New Policy Scenario (roughly 20mb/d difference). The realisation of a constrained oil demand trajectory really depends on how determined policy makers in the developing world are (especially China and India given that these countries are expected to be the main drivers of oil demand growth in coming years) about moving away from fossil fuels. There are some signs of substitution of oil in some of the major economies. China has been implementing strict energy efficiency and emission regulation and data shows sales of EVs and natural gas vehicles (for haulage and transport) are increasing, mainly to tackle local pollution (IEA, 2018). India has also set some aspirational targets for EV penetration although no

⁴ This gap is supposed to be filled by conventional projects already under development, conventional NGLs, extra-heavy oil and bitumen, tight oil outside US, and US shale liquids (see discussion in section 3.3 whether Shale oil can fill this gap).

guidelines have been provided on policies to achieve these targets. The bottom line is if governments' measures lead to a slowdown of oil demand, and its eventual decline, the long term path for oil prices will be lower than today's as some of those high marginal costs producers will not be needed.

Figure 6: Oil supply cost curve and demand under various climate targets



Source: Adapted from https://www.carbontracker.org/wp-content/uploads/2018/11/2degrees-separation-infographic_horiz_Update-01.png

As shale oil has become increasingly competitive in the last few years one might wonder whether it could fill a possible future supply gap? This is an important question because if the answer to this question is positive then it is not unreasonable to argue that the potential response of shale oil might be one of the reasons that international oil companies (IOCs) have been hesitant about sanctioning new expensive mega-projects in recent years. However, in reality, the answer to the aforementioned question is not clear because it depends on three factors. First, it depends on what demand trajectory will be between now and mid-2020. Second, it depends on future volumes of conventional crude oil receiving development approval. Third, it depends on how relatively well advantaged shale oil is going to be at attracting capital in a world where investors are increasingly cautious about funding longer cycle projects, and where the perception of risk only increases towards the 2030s and 2040s amidst the energy transition.

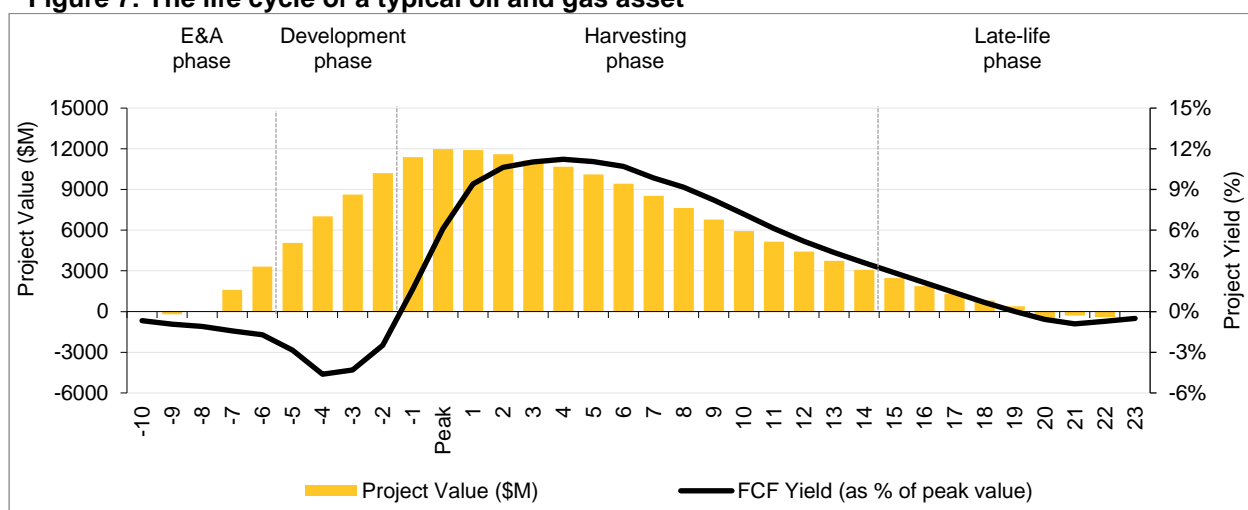
Overall, shale oil is considered a less risky undertaking by investors. In Figure 1, many investors noted a lower 'hurdle rate' for shale investments due to their rapid payback, which is borne out by Figure 3. An illustration is provided by modelling a proposed development of 400Mboe of stacked resource, across 70 square miles of virgin shale acreage, based on assumptions provided in discussion with a large mid-continent US shale exploration and production company (E&P). The project has paid back its up-front costs after five years. After ten years, the project has returned around 3 times its original up-front investment (West, 2018c). Thus if the rest of the industry under-invests, resulting in a price spike, shale projects are well positioned to take advantage of the strong environment. However, whether or not shale can fill any possible supply gap is uncertain.

3.3 How does energy transition risk affect the business strategy of oil and gas companies?

Generally there are three types of companies operating in the oil and gas sector: private equity backed companies, public listed companies (Oil Majors) and national oil companies. These companies often operate across various segments of the value chain but might behave in a different way in the face of a risky transition environment.

Vast amounts of time and capital are needed to create value in the fossil fuel industry. Figure 7 shows the life-cycle of a typical oil and gas asset. Value is created when the field is discovered, appraised and designed. Value is then unlocked when capital is invested to develop a project. Once the field starts up, however, little value is created, only drawn down, with each year's free cash flow depleting the asset base. A consequence of risky energy transition is over-concentration of listed oil and gas companies' conventional activities in the 'harvesting phases' and away from the 'exploration and appraisal (E&A)' and 'Development' phases. In other words, Oil Majors are increasingly moving towards low risk activities. For example, one junior E&P company vented some frustration to us, noting "*We cannot partner with Majors... Many have moved to a zero-risk model... They would rather pay \$500m to back in once you've de-risked an opportunity than pay \$50m to back in early*".

Figure 7: The life cycle of a typical oil and gas asset



Source of data: Redburn. Note: Project value is calculated as the 'average' of a dozen long life projects modelled by Redburn

In a similar manner, private equity-backed companies see themselves as better positioned to unlock value from short-term projects such as emerging shale formations. When value creation was discussed with half a dozen major private equity investors, they noted that their business models inherently discourage long-cycle investments, and so they are not going to pick up the reins if public companies scale back.

Similarly, commenting on a potential deal in the Mancos shale, Wood Mackenzie, the consultancy firm, stated "...smaller, private equity players are able to find more opportunities and in a lot of cases build management teams that are really able to focus in on some of these assets that weren't considered core to larger companies." (Upstream, 2018). In this vein, private companies have raised \$200bn of capital since 2014, primarily to take advantage of the short-cycle opportunities in US shale.

This leaves national oil companies, which are not subject to the same kinds of environmental scrutiny and disinvestment pressures facing large public oil and gas firms. But some commentators have questioned whether this group is well-incentivised or well-placed to unlock enough new supply, or replace \$600-900bn per annum of recent spending from the publicly listed oil and gas companies. This is because many national oil companies often do not have the necessary know-how, capital and finance

capacity to expand their business in the international markets. Historically, IOCs have undertaken over 70 per cent of global investments in both upstream and downstream (IEF, 2018). This means without IOC's participation it is unlikely that national oil companies on their own would be able to meet the investment and financing gap.

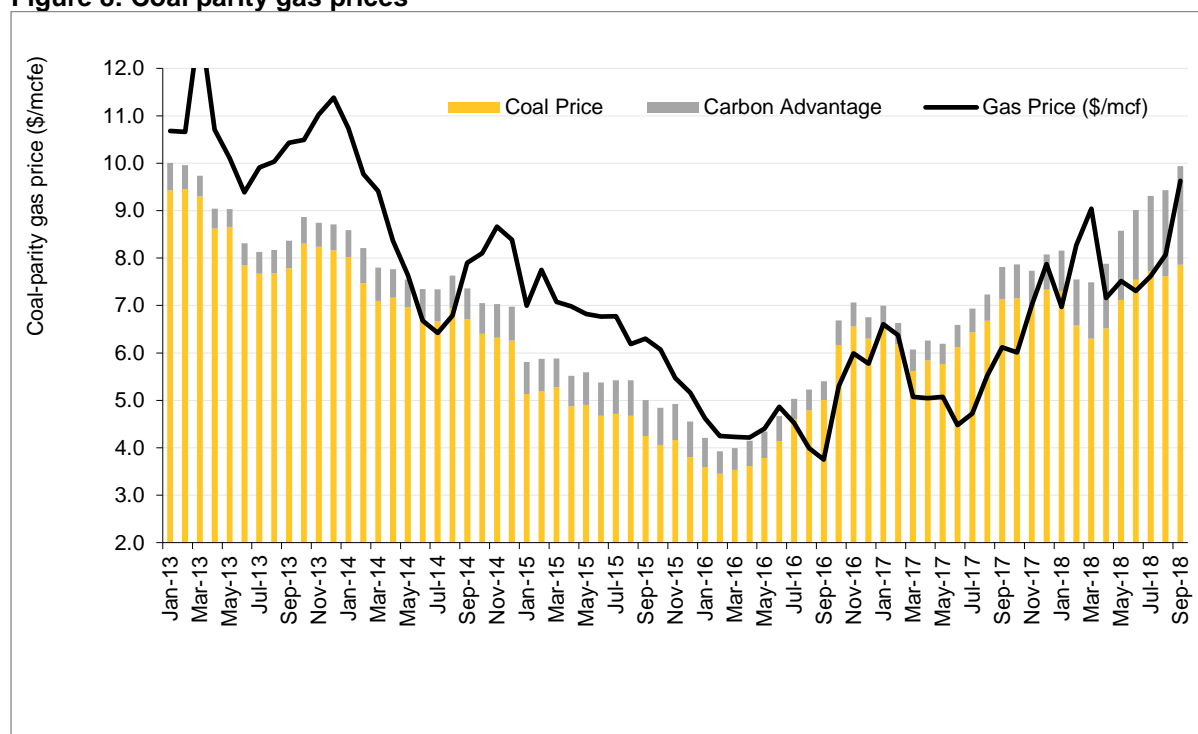
3.4 Is there a spill-over effect as a result of change in risk preferences?

As is shown in Figure 1, the average IRRs required for investors to be comfortable with financing new coal projects was the highest across our entire sample, as much as 40 per cent. It does not require much of a logical leap to see how underinvestment in new coal mines could lead to higher coal prices. However, an interesting question is whether this might have any implications for other energy sectors?

In some markets there is a correlation between coal and gas prices. For example, there is a link between coal prices and gas prices in Europe, which derives some 20 per cent of its electricity generation from each of these competing fuel sources. When coal prices are higher (lower), then European gas trades commensurately higher (lower), see Figure 8. Currently, \$10.5/mcf gas pricing is justified in 2019, if gas is going to price at parity with \$100/ton coal and €20/ton carbon prices in the power sector. This means, in the short term, that underinvestment in coal could push up gas prices, but in the long run the effect is immaterial because supply from additional sources (for instance, increase of gas transport from Russia and new LNG coming online) could compensate for any loss of coal.

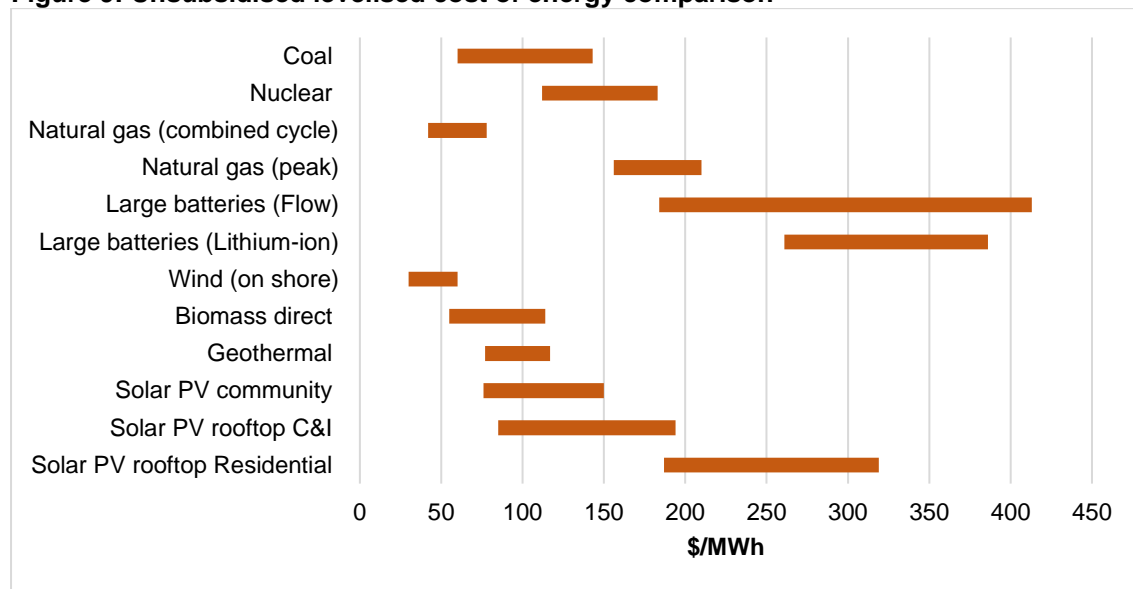
However, there is also a broader issue here. An increase in the price of coal and natural gas due to risk and the spill over effect will improve the economics of alternative energy sources, energy efficiency and storage. As is shown in Figure 9, certain alternative energy generation technologies, such as onshore wind, are already cost competitive with conventional generation technologies. The levelised cost of energy (LCOE) of conventional generation technologies is sensitive to fuel price which means a fuel price surge will make a wider range of alternative energy sources competitive. This might boost the speed of energy transition and create a new form of lock in and path dependency.

Figure 8: Coal parity gas prices



Source of data: Redburn. Note: Coal, gas and carbon prices have been tabulated from Bloomberg and converted into gas-equivalent units.

Figure 9: Unsubsidised levelised cost of energy comparison



Source: Compiled by authors from Lazard (2017)

4. Conclusions

The uncertainty induced by energy transition has already started to alter the risk preferences of investors in fossil fuel projects. Investors in fossil fuel are demanding higher hurdle rates in order to invest in coal and long cycle oil projects. It has been argued in this paper that this change in risk preferences would have several key implications for fossil fuel markets. It extends the payback period of discounted investment costs into a more uncertain future part of the energy transition period and thus dis-incentivises investment in long cycle projects. It also concentrates upstream investment around short-term projects with shorter payback periods. This is because the higher the discount rate, the more weight is given to short-term cash flows and hence to short-term drivers rather than long-term trends. Furthermore, it causes the oil and gas companies to adjust their operations strategy and focus more on harvesting phases of oil and gas fields (low risk operation model) and away from E&A and development. Also, it could affect the volume of available supplies if there is not enough investment into the sector. Moreover, it could affect the long-term oil price when energy markets start to price in transition related risks. Additionally, it could speed up the energy transition process as higher long-term fossil fuel prices improve the economics of alternative resources.

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