INTERNATIONAL ENERGY AGENCY

INSIGHTS SERIES 2018

State of play of upstream investment

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Executive summary

The completion of the Paris Agreement raised awareness of the investment trajectory consistent with climate stabilisation. The largest proportion of the unburnable carbon that has to stay underground is coal. Nevertheless, oil and gas investment has a special macroeconomic significance that could trigger a debate on potential stranded assets and financial dislocation should the investment activity of the industry become inconsistent with a climate pathway leading to stranded assets.

On the other hand, given the continuous importance of hydrocarbons for the global economy, a timely investment consistent with demand patterns in oil and gas supply remains a crucial component of energy security during the transition decades. High oil and gas prices driven by scarcity not only help clean energy sources but also facilitate investment in scalable, high-carbon alternatives as well. The oil price cycle that has unfolded since late 2014, coupled with expectations of an accelerating energy transition, has triggered a profound transformation of oil and gas upstream investment. The industry reduced and restructured its investment activity: oil and gas upstream investment spending has stabilised at a level that is over 30% below the 2014 historical peak. This is an aggregate of a structural shift from high lead-time, large and often-high carbon assets towards light tight oil and smaller, modular brownfield developments. Management discipline, technological progress and slack in the supply chain reduced upstream costs although in North America there are signs of renewed cost inflation.

The financial position of the industry is stable. Major international oil companies are reducing debt and returning capital to equity markets. The United States (US) light tight oil industry succeeded in maintaining its access to capital even during the downturn, and it is on track to become a mature, financially sustainable business. Overall, access to capital does not represent a serious constraint to ramping up investment should market or geopolitical developments necessitate it since the industry has low leverage, and returns capital to equity markets is relatively immune to financial dislocation. The only segment of the oil and gas industry with a high debt is North American shale, whose short time horizon mitigates the financial impact of the long-term climate policy.

In the International Energy Agency (IEA) Sustainable Development Scenario (SDS), which models a pathway well below 2 degrees that is consistent with the Paris Agreement, global oil demand declines – but by considerably less than the loss of existing production due to geological depletion. As a result, substantial field development investment is completely consistent with the energy transition, and it remains a key component of energy security. The current investment activity of the oil and gas industry is broadly consistent with the SDS in terms of investment spending and field development sanctions, as well as project composition and an emphasis on gas. This creates a window of opportunity for a smooth energy transition without major stranded asset problems. On the other hand, policy-driven investment in efficiency and low-carbon alternatives affecting oil demand is clearly inadequate to keep oil demand at the level of the SDS. This creates the risk of triggering a boom-and-bust cycle and, eventually, a financially disruptive, disjointed energy transition.

The Faster Transition Scenario (FTS) developed in the context of the 2016 German G20 presidency has a tighter carbon budget that is within the interval of 1.5 degrees pathways. This has a stronger impact on oil and gas investment but does not fully eliminate field development. In the Faster Transition case, some of the previous exploration investment becomes stranded as the resources stay underground; nevertheless, the scale of stranded assets is manageable from a macroeconomic point of view if demand mitigation policies are implemented in a timely fashion.

Introduction

Oil and gas combined represent more than half of global primary energy supply. In the past three years, the share of oil and gas has increased in the global energy mix as low oil and gas prices stimulated demand and both macroeconomic and energy policy drivers pushed up the use of gas. Despite the progress with low-carbon technologies, hydrocarbons remain difficult to substitute in important sectors such as oil in transport, and petrochemicals or gas in industrial energy use. Under the very robust climate policy assumptions of the IEA SDS, global oil and gas demand combined in 2040 is only 5% lower than today (although their relative weights in the energy mix change significantly compared with the current situation), and is concentrated in the difficult to substitute sectors. Consequently, oil and gas supply security remains a relevant policy concern as, even on a decarbonisation path, economic growth and welfare will be influenced by oil and gas markets for decades.

The rate at which the output of currently producing oil and gas fields declines is a defining factor in future upstream investment needs. Whereas power generation assets maintain their rated capacity for a long time, so in countries with stagnating demand even a substantial period of underinvestment might not lead to market tightness, this is not the case for oil and gas supply. Production declines vary from field to field, and they are strongly influenced by the operator: in general, there is a trade-off between the decline rate and ongoing secondary investment on a given producing asset. The natural decline rate of conventional crude oil fields, intended as the drop in production in the absence of any investment in the asset, is close to 9% per year. This implies a rapid drop in global oil output, should all operators cease to sustain production through continuous investment. However, a wide range of measures can be undertaken by companies to sustain pressure in the reservoirs, enhance the amount of oil recovered, and slow this decline rate.

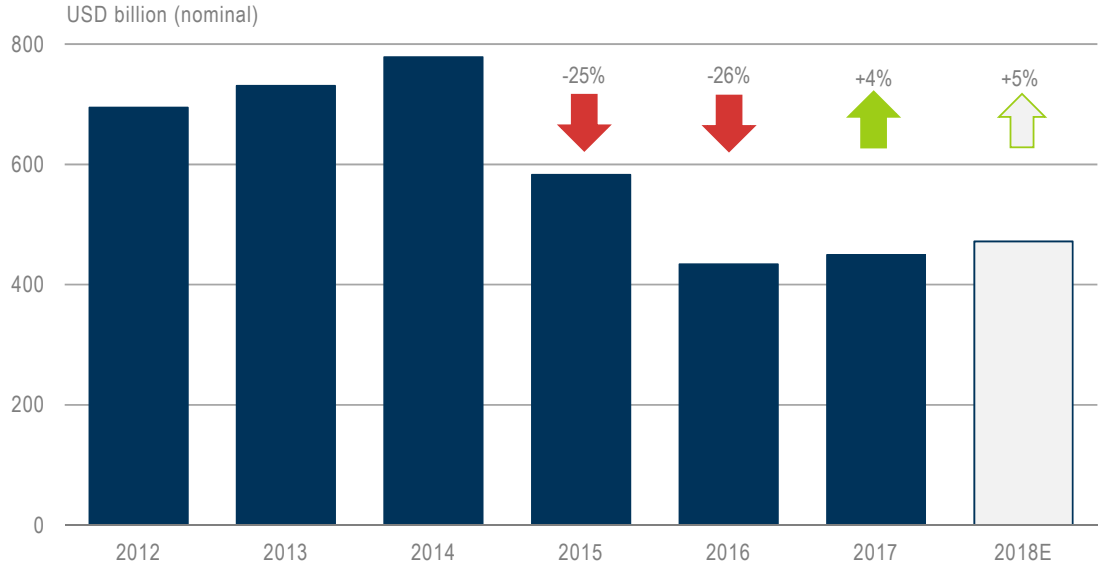
According to IEA analysis, the global average decline rate for conventional oil fields beyond their peak is around 6%, although this varies substantially according to asset type, location and size. As a result, a significant share of upstream capital investment is related to replacing declines in mature production rather than supplying demand growth. Very importantly, despite the series of investment cuts unfolding in the past three years, the average decline rate appears to have dropped. This is most likely due to a combination of several factors, notably a marked shift of investment towards already producing assets (meaning that the share of so-called “sustaining capex” has been gaining market share) and remarkable technological progress, including digitalisation, leading to better reservoir management as well as intense management focus on field operations. The lower decline rate is equivalent to around 1 million barrels per day (mb/d) supply not lost annually compared to decline rates prevalent in 2010. While the capex implications are difficult to untangle, it would appear to be considerably less capital intensive than developing the equivalent 1 mb/d new greenfield supply. Still, even after the recent progress, around 3 mb/d production still needs to be replaced every year. If US tight oil were the only growth area in upstream investment, it would need to ramp up at nearly twice its maximum growth rate just in order to stabilise global oil supply. In addition, it is worth emphasising that tight oil and shale gas, which are the most rapidly growing oil and gas supply sources, have very high decline rates, in the order of 50% in the first year of production and approximately an additional 35% in the second year. They require constant reinvestment in new wells to compensate for declines in existing wells. To put 3 mb/d into context, in the *World Energy Outlook* (*WEO*) SDS, which relies on very robust climate policy assumptions, by the 2030s a large-scale deployment of electric cars and efficiency measures leads to a 1.4 mb/d annual decline. New field development investment will be needed even decades ahead in the low-carbon transition.

Recent investment activity has been characterised by a sharp cyclical reaction to the downturn of oil prices from late 2014. In addition, rapid technological progress in multiple areas of the energy system and climate policy-induced concerns about fossil fuels as potential stranded assets, contributing to depress investment behaviour. The industry did not start the adjustment from an equilibrium position. The persistently high, and seemingly stable prices in the first half of the decade, triggered an unprecedented investment wave into not only US tight oil but also substantial investment into long lead-time, long lifetime assets such as Canadian oil sands, Brazilian pre-salt or, in the case of gas, Australian liquefied natural gas (LNG). As a result, by the time the price decline triggered an adjustment of investment activity, a medium-term increase in production capacity was already locked into sunk cost, largely irreversible projects.

Recent developments in upstream investment

The overall result of oversupplied markets and price decline in 2014-16 was a significant fall in global upstream investment. After capital spending in the sector had been rising almost constantly in the first half of the decade, the 2015 drop amounted to 25%, followed by another 26% in 2016. The total investment cut exceeded USD 330 billion in just two years (in nominal terms), an unprecedented occurrence. Moreover, 2017 global upstream investment spending remained flat and, according to preliminary data for 2018, upstream investment is expected to increase by only around 5% as companies are keeping financial discipline and cost control as key pillars of their activities.

Figure 1 • Global investment in upstream oil and gas



Notes: E = expected.

Sources: Based on announced company spending plans and guidance as of May 2018.

The impact of cyclical developments on investment varied significantly across regions. In the period 2014 to 2016, North America experienced by far the largest contraction, mainly due to the US shale sector, which was able to adapt to the next context in a much more rapid way given its short cycle nature. New deep-water activities were also significantly reduced during 2015-16 due to requirements of large upfront capital investment and the long lead-time nature of the projects. On the other side of the spectrum, spending in the Middle East and the Russian Federation (hereafter,

"Russia") remained resilient thanks to very low-cost resource base and in the case of Russia, due to depreciation of local currency that helped the profitability of domestic service industry.

In the Middle East, due to the large low marginal cost resource base, strategic decisions by governments are a stronger determinant of upstream investment than short-run cyclical developments. Despite the Organization of Petroleum Exporting Countries (OPEC) decision to constrain production, most Middle Eastern producers such as Saudi Arabia, United Arab Emirates and Kuwait maintained robust field development programmes in order to keep and even increase production capacity. They also took advantage of the excess service sector capacity to improve their contracting position versus the main service providers. Despite low oil prices, field development in Iran benefited from the lifting of the sanctions and improving access to capital. This led to a recovery of oil production; Iranian gas production has reached an all-time peak. The reintroduction of the sanctions will certainly have a detrimental impact on investment in Iran, but the scale and severity of this impact is still uncertain.

Iraq faced a combination of military conflict and infrastructure bottlenecks. Ongoing field development, especially in the southern supergiant fields, led to a production recovery, but new field development and infrastructure investment is lagging, and some companies have already announced intentions to reduce their activity in Iraq's operation. In an attempt to revitalise the sector, in 2018 Iraq's government has offered revised contract terms during its fifth bid round, but the response of companies so far has been modest, also for continuous security preoccupations in some areas offered in the bid.

The highest profile new field development in the Middle East–North Africa (MENA) region is not a conventional producer country, but Zhor, a giant gas field offshore Egypt. Several countries in the MENA region have shown strategic interest in gas developments as, despite the abundant geological resources, previous underinvestment led to gas shortages and increasing import dependency across the region. Egypt is a very good example: with robust growth in gas demand for power generation, the government halted LNG exports and increasingly turned to imports. The strong energy policy benefits of domestic production were translated into a supportive investment environment. The project developer, Eni, chose a streamlined development model and completed the field at a time and cost that would have been inconceivable for a field of Zhor's size before 2015. The size of Zohr field and encouraging prospects for further discoveries in adjacent areas leaves open the possibility that Egypt could join the club of LNG exporters in the near future, while also meeting its domestic needs.

Upstream investment in Russia has faced a perfect storm of lower oil prices, sanctions, higher geopolitical risk and continuous questions over ownership rights and contractual security. Despite these challenges, the Russian oil and gas industry surprised on the upside. Robust upstream investment stabilised oil production at a post-Soviet peak at 10-11 mb/d, whereas large and complex gas projects have successfully gone ahead. The most important reasons for the Russian resilience appear to be the following:

- The sanctions directly affected the ambitious Arctic offshore exploration programme, which seems to be on hold. However, similar artic prospects have also been suspended on the North American side, driven by business strategy considerations. Given the maturity of the West Siberian resource base, Arctic developments would eventually have to play a role in Russian energy strategy that envisages the stabilisation of oil production at roughly the current level until the 2030s. However, their impact on production prospects until 2025 is negligible. Even if geopolitical risk were mitigated, it is doubtful that private investors would commit serious investment to Russian Arctic prospects unless the Russian government implemented a very attractive tax regulation. Even Gazprom, with its strong commitment to execute the government's energy strategy, suspended indefinitely the Stockman artic

offshore development, whose business model was already disrupted by North American shale production. East Siberian developments have also retrenched to prospects like Vankor that are adjacent to the West Siberian core production areas.

- While long lead-time frontier developments in the Arctic or in East Siberia are not progressing, there are very promising opportunities for brownfield developments and enhanced recovery in the mature areas of West Siberia. This has been the focus of activity by the Russian oil and gas industry. Even though sanctions affected the access to technology, Russia has a domestic service sector with respectable capabilities, especially for infill drilling development, horizontal drilling and various other enhanced recovery projects. Because development costs are predominantly in roubles, exchange rate effects led to an exceptionally strong cost deflation and supported robust investment.

- The gas projects aimed at diversifying Russia's exports to Asia have made mixed progress. Vladivostok LNG is suspended, and a Sakhalin expansion is facing uncertain prospects. On the other hand, the Power of Siberia pipeline to the People's Republic of China (hereafter, "China") is progressing and Yamal LNG was completed ahead of schedule. Both projects benefit from a strong strategic partnership with China. Power of Siberia will entirely serve the Chinese market. For Yamal LNG, the exports are likely to be diversified, but with equity from CNPC and the Silk Road Fund and a major project-financing package from Chinese banks, the majority of the financing for the project is Chinese. Neither project represents the redirection of exports from Europe; they are disconnected from the main production system serving European Russia and European Union (EU) exports and they unlock new resources that otherwise would stay underground.

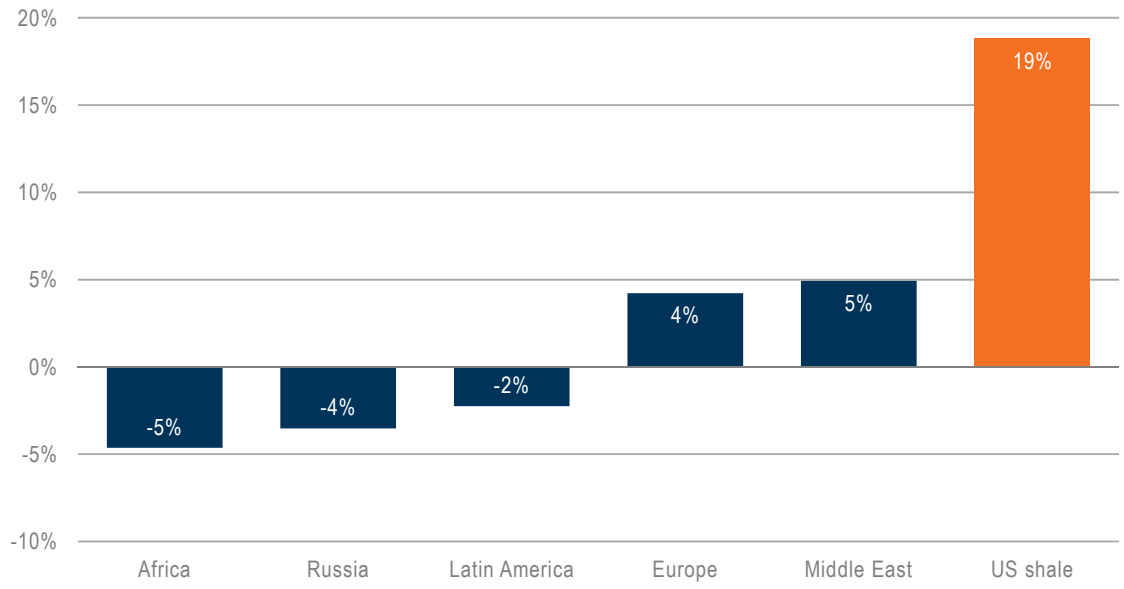
Overall, Russia's ability to navigate troubled times has been remarkable. As of mid-2018, results posted by most of largest Russian state-backed companies showed solid returns and improved financial conditions. Furthermore, the country has been extremely active with its energy diplomacy, enhancing relationships with other key actors on the global energy scene such as China and Saudi Arabia; in August 2018, it signed a first deal with four other countries aimed to resolve a 26-year-old dispute concerning the Caspian Sea.

The recovery of oil prices in 2017 and the further tightening of oil markets in the first half of 2018, coupled with a significant reduction of upstream cost, have led to a modest and uneven recovery of investment spending. Conventional onshore investment has recovered somewhat, especially brownfield investment in already producing resources in the Middle East, Russia, China and elsewhere. On the other hand, offshore investment spending is still declining, although the field development impact of this is mitigated by cost deflation, and there is renewed investor confidence in deep offshore. Deep offshore field development investment decisions in 2017 regarding reserves sanctioned returned to the level that was prevalent in the USD 100/barrel period as they benefited from ample excess capacity in rigs and service ships, declining costs, and re-engineered projects for more modular, shorter-cycle completion. Throughout the second half of 2017 and first part of 2018, the majority of new conventional projects sanctioned are in deep water. However, given project lead-times, spending in new projects is not yet sufficient to offset the decline in activity of those projects sanctioned in the pre-crisis period and which are now reaching completion. The recovery of global upstream investment is driven by a brisk acceleration of investment spending in the US shale sector. As oil prices rose, improving project economics and the financial stability of the industry, investment spending increased in 2017 by over 50%, followed by another increase in 2018 that is projected to be around 20%.

Overall, US shale remains the key growth area of global upstream investment, although the rise of investment in 2018, at about 20%, is lower than during the previous year, when spending

bounced back by over 50%. Spending in the Middle East has remained relatively resilient throughout the last few years, and it is expected to increase modestly in 2018, driven mainly by investment in brownfields and increasing focus on exploitation of domestic gas resources. Europe's growth is entirely led by expanding activities in the North Sea, while the expected modest decline in Russia is mostly due to currency depreciation.

Figure 2 • Change in upstream investment by selected region, 2017-18



Sources: Based on company reports.

Upstream investment across the value chain

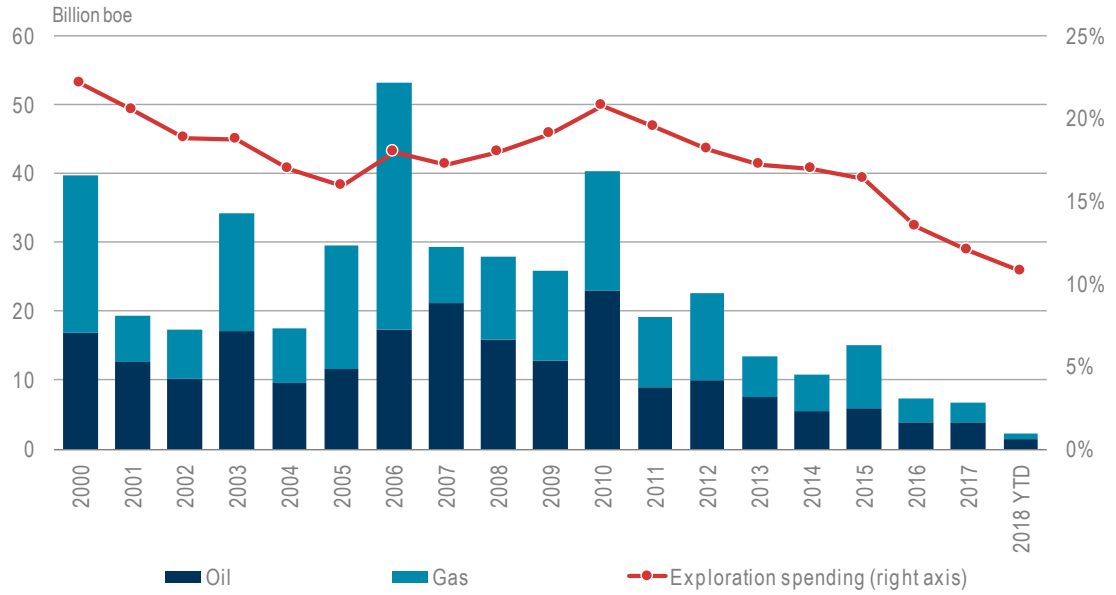
The large majority of the capex reduction seen in previous years happened in new greenfield projects and – when possible – in reducing the scope of projects that were already sanctioned, with the aim to keep spending under control as much as possible. The overall result is that while the share of investment allocated to greenfield projects was over 40% in the years immediately preceding the 2014 price collapse, we estimate that in 2018 this value will drop to around one-third of the total, enhancing concerns for the long-term adequacy of supplies.

The abrupt reaction of industry also had important spillovers across the entire value chain, initially in the oil and gas service sector, which was also coming off from a very dynamic period that led to oversized level of equipment investment in different parts of the chain.

Exploration spending was especially hit hard, more than halving since 2014. Although exploration spending affects discoveries only with a time lag, new discoveries have already fallen to a multi-decade low. Global conventional crude discoveries dropped to a record low at 2.8 billion barrels in 2016. In 2017, discoveries increased only marginally to 3.2 billion barrels, with around half of that from deep-water areas in Guyana, Mexico and the United States. There was also a large discovery in onshore Alaska at the beginning of 2017. It should be noted, however, that in recent years the substantial majority of reserve additions has come not from new discoveries but re-evaluation of existing assets, primarily in the light of better understanding of the reservoir and technological progress increasing recovery factors. Moreover, North American tight oil, which has represented the large majority of the production increase in the past decade, does not have a distinct exploration-discovery phase of development. Rather, in the case of tight oil, the theoretical shale resource base is typically known well in advance. Successive development drilling leads to a better understanding of reservoir characteristics and often adjustments of the

resource estimates. In a favourable case, gradual improvements in adjusting drilling and fracking techniques to the local characteristics lead to a positive revaluation of the resource estimates, which has been the case for most major US shale plays. Alternatively, disappointing geological results or persistent aboveground challenges can lead to large negative reassessments, as was the case in both Poland (due to geology) and California (due to lack of social acceptance).

Figure 3 • Global discovered conventional resources and the share of exploration in total upstream investment



Note: YTD = year to date.

Source: Based on Rystad Energy (2018).

While the trend in conventional oil discoveries shows clear evidence of the challenges that the sector has been facing, it does not create any immediate concern in terms of supply adequacy. This is due to the large known resource base, as well as to the contribution of US oil supply, which is expected to meet about 80% of global oil demand growth in the period up to 2025 (predominantly from shale activities, tight oil and natural gas liquids [NGLs]).

Exploration activity remained active in regions where the overall attractiveness of the geological play is already confirmed, especially if development benefits from adjacent already existing infrastructure and the energy policy stance are supportive. Despite the maturity of its resource base, Alaska experienced notable exploration success, raising the prospect of a prolonged operation of sunk cost pipeline infrastructure. Exploration activity also remained intense in the Eastern Mediterranean, where previous discoveries and close proximity to large gas markets increase both geological and commercial attractiveness. In contrast, Arctic exploration was heavily cut back and major oil companies abandoned prospects in Alaska, Canada, Greenland and Russia. The only remaining Arctic region with intense activity is Norway. The Barents Sea developments are geographically easier to manage than most other Arctic prospects and they benefit from both a measurable cost deflation, the existence of a strong service industry, as well as supportive royalty policies.

Field development represents the large majority of total upstream investment. Field development investment involves drilling the production wells as well as constructing the gathering and treatment infrastructure. During the cyclical downturn, a substantial proportion of field development investment focused on projects that were already beyond the final investment

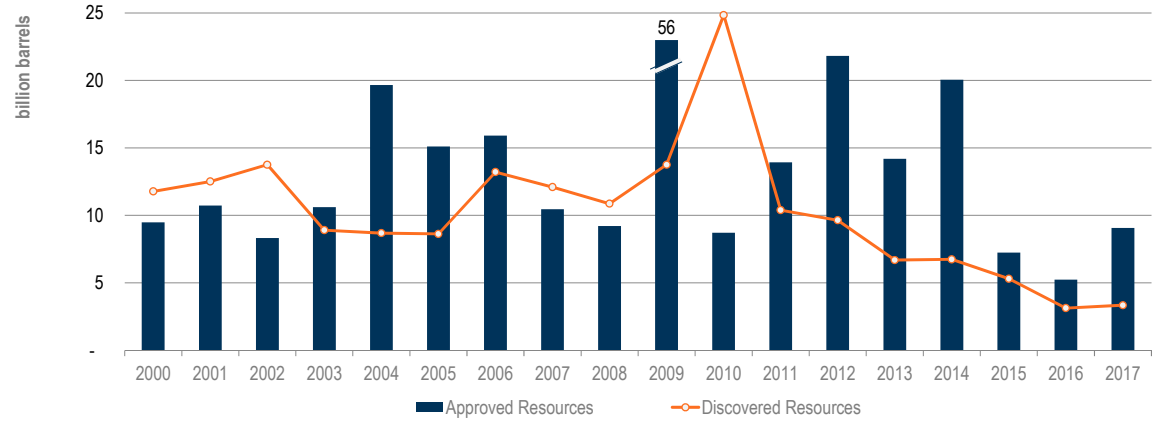
decision or already in production phase. Several of those large projects are generally regarded to have a low likelihood of recovering their full investment cost in the new market environment, so the continuing investment is aimed at minimalising stranded assets.

New field development sanctions declined to a multi-decade low by 2016. The volume of conventional resources sanctioned for development in 2016 fell to 6.1 billion barrels, just one-third the amount of resources sanctioned on average in the previous 15 years and one of the lowest levels since the 1940s. In 2017, the volume of sanctioned conventional crude oil volumes has been increased to 9.2 billion barrels although this remains a low level when compared with the historical average. Nearly half came from onshore projects in Iraq (the redevelopment of Majnoon and Halfayah), and there were also large approvals in ultra-deep-water Brazil, North Sea offshore and the United States part of Gulf of Mexico. Approvals in West Africa remained very limited, and in 2016 and 2017, were at their lowest levels since the 1950s when the area was opened up for exploration.

Given the time lag between sanctioning of new projects and start of production (on average 3-5 years according to the size and complexity of the projects), this could lead to market tightness in a few years' time. New investment decisions faced not only a cyclical downturn but had to cope with several other challenges:

- deterioration of finance conditions that forced companies to become significantly restrictive in capital allocation
- uncertainty over the strategic reaction of OPEC, which was seen as an investment risk, especially during the period before the agreement between OPEC and other key producers to rebalance markets
- an unexpected resilience of US tight oil that proved its ability to maintain high output levels, despite reduced activity
- heightened technological uncertainty, mainly on the demand side (the potential of electric vehicles (EVs) and other new technologies to cut into oil demand).

Figure 4 • Conventional oil resources discovered and sanctioned



Source: IEA analysis of Rystad Energy data.

Adaptation of the industry to a new market context

The industry reacted to these challenges by a sharp change in the structure of investment projects within a smaller investment budget. After several decades, during which the average size, lead time and technological complexity of upstream projects had been increasing, the industry refocused on

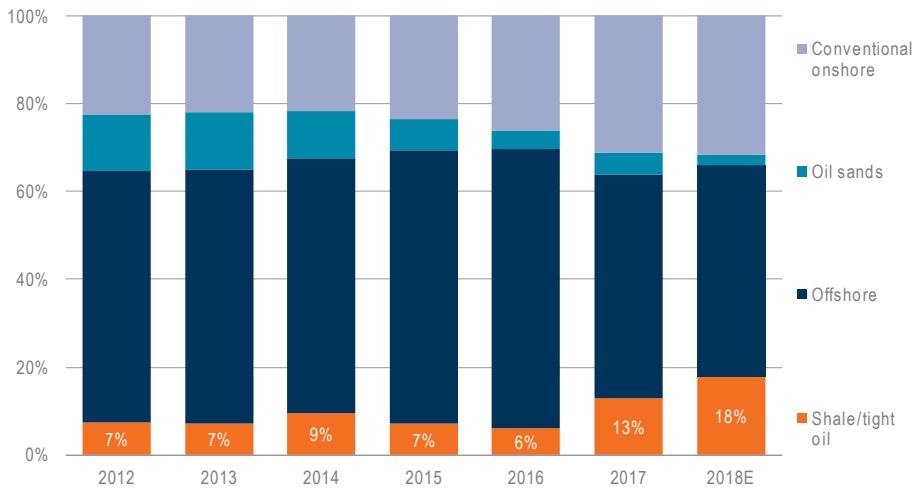
shorter lead times and medium-sized projects. This is not simply the case of focusing on the most cost-efficient opportunities. Some very large projects, such as conventional giants in the Middle East, can have very attractive long-run marginal costs due to their large future production volume. The focus on smaller, medium-sized projects is driven partly by other factors as well:

- The previous decade of megaprojects led to a series of cost overruns, project delays and production shortfalls. Because of the 2014-17 downturn, there is now a considerable degree of investor scepticism about long lead-time megaprojects. Smaller, shorter cycle projects are in general less technically complex and the prospects of a timely and within budget completion are more likely.
- Publicly listed oil and gas companies have been under intense shareholder pressure to maintain dividend payments, and bridge the cyclical downturn with increased borrowing. This created a strategic preference towards project that will generate cash flow already in the short- and medium-term time horizon.

Last, but not least, especially in the case of companies listed in Western European stock markets, a measurable strategic shift has taken place since the completion of the Paris Agreement. Several major oil companies have created strategic analysis of low-carbon pathways, on the record discussing the possibility of peak oil demand in the near future, and made investments into low-carbon technologies. While with the exception of DONG (now known as Ørsted), investment in low-carbon sources remains a small proportion of the capex budget and their strategic stance emphasised the continuing need for hydrocarbons. Notwithstanding, the prospect of a low-carbon transition increasingly affects portfolio choices. In this respect, an investment portfolio that is a combination of tight oil, medium-sized, relatively fast field development prospects including brownfield projects and gas is perceived as relatively well positioned to generate decent returns while minimising potential risks related to the adoption of ambitious climate policies.

The major oil companies — although to a different extent — all moved their portfolio in the direction to reduce the number of projects with long lead times, high technical complexity and an unattractive carbon footprint. Companies like Shell and Conoco have divested the majority of their stakes in Canadian oil sands. Others, including Chevron and Exxon, have radically shifted their portfolio towards US shale assets, while Total and Statoil have been targeting promising assets in the deep-water area, also to lock in what is currently considered an attractive cost structure.

Figure 5 • Upstream oil investment by major oil companies adjusted by cost inflation, by asset



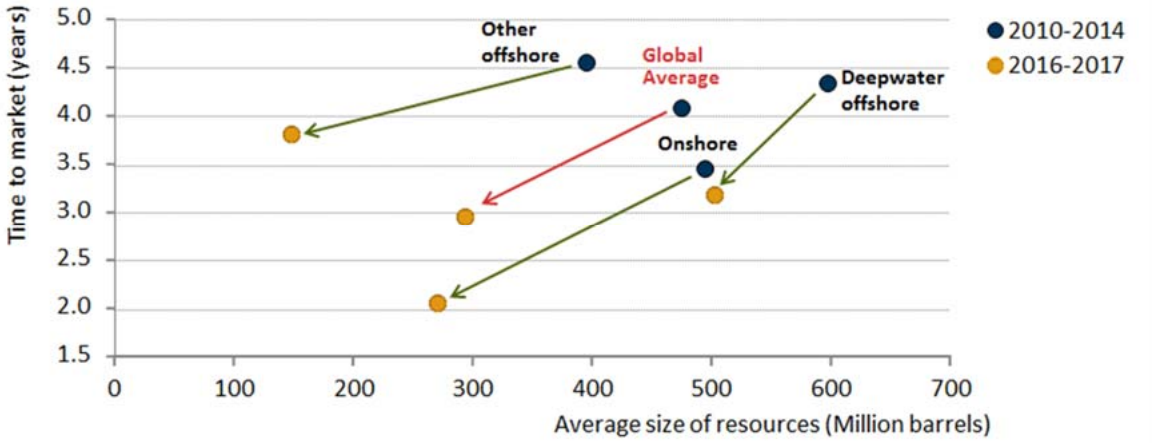
Source: IEA analysis of Rystad Energy data.

In some important cases, projects themselves moved to the "smaller, shorter cycle" category instead of this strategic imperative, leading to a different project selection. The case of majors is striking, with a rapid rebalancing of their upstream investment allocation away from oil sands projects and rapid shift towards shale activities. This has resulted in a share of upstream investment allocated to shale projects estimated to reach 18% in 2018, three times larger than just two years ago.

In the conventional sphere, oil companies have made strong efforts to reengineer their project prospects and adopt a streamlined, modular development approach that could lead to lower investment cost and easier project management. Major field developments that went ahead after a period of strategic reconsideration like Mad Dog 2 in the US Gulf of Mexico or Johan Sverdrup offshore of Norway were not sanctioned as originally planned in terms of size and scope. Shell's Vito project, sanctioned in April 2018, is another example, having reduced its costs by 70% compared with original plans and fast-tracked the start-date of operation. The marked cost deflation that played a crucial role in securing the investment decision for the projects was not only – and not even – primarily driven by the deflation of input costs, but reflected a comprehensive redesign of the projects. This often keeps the option for a further expansion, should market conditions justify it.

The overall result is that, further to enhanced focus on shale activities, conventional projects that have also been sanctioned over the last couple of years tend to be on average smaller and to deliver first production sooner than previously. This has significant implications on the dynamics of the oil markets, with more focus on short-term price dynamics likely leading to enhanced volatility.

Figure 6 • Average size of conventional resources sanctioned and time-to-market



Source: IEA analysis based on Rystad.

The rise of unconventional supply

Unconventional development is a combined term covering a wide range of technologies and project classes. The different classes of unconventional development represent the opposite ends of the lead-time and technology complexity scale compared to conventional oil and gas: Oil sands and gas or coal-to-liquids conversion projects are very large, technically complex and often have a decade or more of lead-time. In the absence of carbon capture application, their carbon footprint is unattractive. On the other hand, after completion, they produce for decades at a low short-run marginal cost. Shale gas and tight oil projects are much faster individually, offering modular development, and, in an established shale play, they have lead-times measured in

months. Due to their high decline rates, the first two years dominate the net present value of the project. Importantly, this is within the time range of liquid futures trading, so hedging, which is not usual for conventional oil, is a credible option for shale projects.

Large investments into oil sands projects and, to a lesser extent, into coal conversion in China have played a measurable role in the ramp-up of production capacity pre-2015. The medium-term growth of Canadian oil sands production has already been locked in by the financial investment decisions (FIDs) made before the oil price collapse. While these projects face significant headwinds in the current context, they did generate sizeable investment activity in the past three years as well. On the other hand, there were no FIDs in new oil sands projects, and, especially in the case of the large, multi-billion dollar *in situ* upgrade projects, there is general investor scepticism of any new project going ahead in the near future. To the extent that there are preparations for new project activity, they focus on the steam-assisted gravity drainage technology, which offers a shorter lead-time and more modular development.

Since Pearl GTL in Qatar a decade ago, there has been no FID in a major gas-to-liquids project, despite some initial interest after the emergence of US shale. Coal conversion (to liquids or gas) projects are almost exclusively concentrated in China. These projects exemplified a policy-driven investment cycle. Initial enthusiasm at the first half of the decade was disrupted by concerns about the water use and emission footprint of the projects, as well as lower international gas prices. However, in 2017, the coal-to-gas switch, driven by air pollution objectives and widespread gas shortages, led to skyrocketing Chinese LNG imports, a trend which continues in the first part of 2018, bringing a renewed strategic interest and policy support for coal conversion projects. Developments in China towards increased utilisation of coal conversion technologies will ultimately affect the country's import needs, with potential implications for international oil and gas markets.

Tight oil in North America represented 60% of the global increase in oil supply this decade. Up until 2017, tight oil had been dominated by North American independents. For both technological and financial reasons, tight oil investment proved to be the most resilient and at the same time the most volatile component of the upstream landscape. It took the vast bulk of adjustment in 2015-16 and rebounded sharply starting from 2017. The technological driver of the volatile adjustment is the combination of short project cycles and high decline rates. For a mature shale play, there is very little predetermined investment locked in by previous investment decisions. Moreover, given its short-term cycle nature, the widespread industry practice of using a cyclically adjusted trend "hurdle rate" oil price representing a long-term average for investment assessment of long lifetime projects is not appropriate. Shale production is routinely hedged on futures markets. While the term structure of the futures curve varies, time arbitrage creates a powerful link between spot and futures prices. As a result, commodity price fluctuations have an immediate impact on the investment assessment of shale projects resulting in rapid propagation on real investment activity.

The physical characteristics of shale are reinforced by its unique financing model. Whereas large oil companies finance their conventional projects primarily from internal cash flow, the rapid growth of shale production strongly relied on external sources of finance, including debt, equity raising and assets sale. Given the highly leveraged balance sheet of most shale independents, both the cost and difficulty of access to debt finance is inversely related to oil prices. In periods of low oil prices, not only the future cash flow of shale projects declines, but the cost of capital also rises as bond markets price a higher default risk. On the other hand, as markets rebalance, a broader selection of shale projects becomes economical and access to bond finance becomes easier at the same time. The corporate bond market is thus acting as a volatility amplifier and together with the technical characteristics of shale has led to an exceptionally volatile investment cycle. Overall, the shale industry has seen notable improvement in financial conditions over the

last 12 months, though the picture varies markedly by company, and the overall health of the industry remains fragile. We explore this in more detail in the section below.

North American shale gas production has powerful technological and financial linkages with tight oil. Associated gas from tight oil and natural gas liquids from shale gas play an important role in gas and oil markets, respectively, and have an important impact on project economics. Lower than expected oil prices in 2015-16 lowered the financial premium that wet shale gas projects receive from associated liquids, and lead to worsening project economics. Although shale gas benefits from the cost deflation and technological progress of the tight oil prospects, this failed to compensate for the combined impact of lower oil prices and near record low US gas prices. As a result, shale gas drilling retrenched, leading to the first annual decline of US shale gas production in 2016.

In the 2015-16 period, investment into US shale activities plunged by about 70%, but this led only to a modest decline in tight oil production (about 600 000 barrels per day between the March 2015 peak and the lowest point of the cycle in September 2016.) Activity retrenching into the most prolific sweet spots and rapid technological progress reduced costs to the extent that a moderate market rebalancing in 2017 triggered a marked expansion of activity, reaching tight oil production of 5 mb/d by the end of the year. In 2017, investment spending bounced back abruptly, by an increase of more than 50% compared to 2016. Given the rapid improvements in drilling productivity, the rig count is increasingly a misleading metric. Nevertheless, both drilling activity as well as well complexity and lateral length largely expanded, leading to a sharp recovery of tight oil production. For 2018, we estimate that US tight oil production is on track to expand by 1.3 mb/d, the largest annual growth ever achieved.

Shale development outside North America remains subdued. A combination of geological challenges (deeper, more fractured shale layers, less understood geology) as well as above ground issues (social acceptance, lack of a competitive service sector) have slowed down development. Initial expectations proved to be disappointing in continental Europe, South Africa and in most countries of developing Asia. In Mexico, development of excellent shale resources are hindered by intense competition with US exports and a strategic focus on offshore upstream. Outside the United States and Canada, meaningful shale development takes place only in countries with favourable geology and a supportive policy stance. Although an order of magnitude smaller than the US activity, notable cases include Argentina (Vaca Muerta), Saudi Arabia (shale gas for domestic consumption) and China. In the latter case, both the geological and the aboveground geographical conditions are considerably more challenging than in the United States. Russia has considerable shale resources, primarily tight oil in the Bazhenov formation under West Siberia. Some subdued activity is taking place, hindered by constraints on technology access due to sanctions, as well as lack of strategic focus by the Russian majors. Medium-sized independents that played a key role in driving shale innovation in North America have been squeezed out from the Russian oil industry.

Upstream, integrated long-distance gas infrastructure: While to a certain extent oil upstream investment is disconnected from infrastructure development due to the ease of transporting and storing oil, this is not the case for gas.[1] Large conventional upstream gas developments that are not intended for a domestic market are routinely bundled together with infrastructure investment from both a project management and a financing point of view. Investment into the Power of Siberia and the Trans Anatolian pipelines were a necessary precondition for the investment decision into the Chayandinskoe and Shah Deniz gas field developments, respectively; the investment decisions were integrated and led by the same companies (Gazprom and Socar).

[1] In areas where upstream oil activities have rapidly increased, like the US Permian basin, the rise of production required a significant wave of investment into new midstream infrastructures.

Similarly, for virtually all LNG projects outside North America, the upstream field development and liquefaction infrastructure investment are integrated, certainly in terms of strategic decisions, but often in corporate entities and contractual structures as well.

Previous investment decisions brought global LNG investment into an all-time high in the period 2014-15, mostly in Australia and the United States. Annual spending in new LNG liquefaction plants peaked at about USD 35 billion in 2014 and 2015 and since then has strongly declined. Expanding supply, as well as intense competition for gas-fired power generation, both by coal and renewable energy, led to a cyclical downturn of LNG prices. The effect of market fundamentals was reinforced by lower oil prices since oil indexation is still prevalent in international LNG markets. Given that a substantial medium-term increase of LNG supply is already locked-in by the projects under construction, new investment activity sharply decelerated and in 2017 amounted to just above USD 20 billion, largely due to spending in terminals already under construction.

In the past two years, there has been a noticeable gap in investment decisions to new LNG liquefaction projects, with one project begun every six months compared to six major projects starting construction in 2011. Importantly, none of the projects that went ahead are large-scale, land based projects of the USD 10 billion+ category that dominated the 2011-15 investment wave. The projects that did go ahead have a much smaller average size, and they either have brownfield expansions (Corpus Christi train 3 in the United States) or deploy a modular design (Cove Point also in the United States). There is increasing investor interest in floating technology, with smaller floating units that benefit from factory construction. This is completely consistent with the investment strategy focusing on shorter cycle, smaller projects observed in conventional upstream.

However, since 2017 global gas demand and international trade have strongly increased, a trend the IEA expects to continue into the future. China led the increasing demand for natural gas, underpinned by air-quality policies aimed to reduce its reliance on coal consumption.

No major interregional pipeline project has reached a final investment decision since 2013 and there are only three under construction: Power of Siberia, the expansion of the Turkmenistan-China pipeline system and the TANAP/TAP pipelines that will deliver Azeri gas to Europe on the Southern Corridor. In capacity terms, the two projects that link landlocked resources of the CIS (Commonwealth of Independent States) region with Chinese demand represent the large majority.

Developments of upstream costs

Changes in nominal investment spending can have very different implications for physical project completion and future supply capacity depending on the development of upstream costs. The decade leading to 2015 was characterised by systematic cost inflation in the oil and gas industry, which was only briefly interrupted by the cyclical downturn during the financial crisis of 2009. The most important drivers of the cost inflation appeared to be the following:

- With a substantial proportion of the low marginal cost of oil resources controlled by national oil companies (NOCs), the industry was forced to move to complex, technologically challenging projects. As the project size expanded, the various engineering and project management challenges multiplied.
- Especially for projects located in remote regions, availability of skilled labour on site became a major constraint and a source of cost inflation.

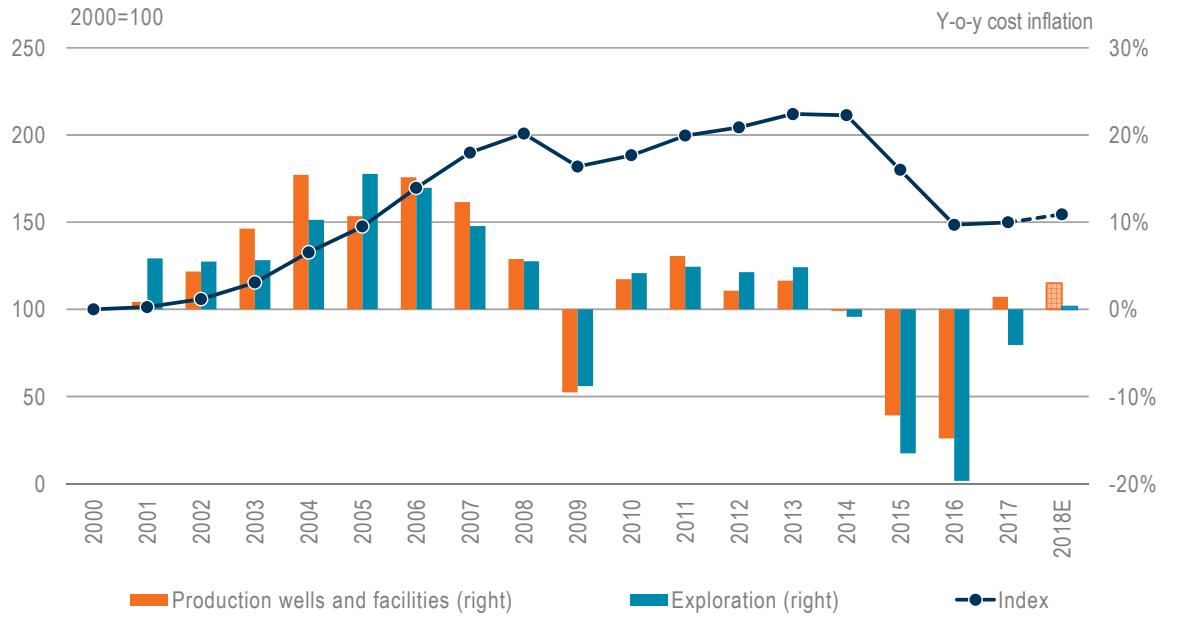
- The 2010-15 period coincided with a general infrastructure investment boom in emerging economies, leading to price increases of commodities and various technical services.
- Although it is difficult to quantify, there have been persistent concerns about a long period of high oil prices leading to management complacency and insufficient focus on cost management.

According to the IEA Upstream Investment Cost Index, in the decade preceding the 2008-09 financial crisis, upstream costs doubled and – after a temporary plunge given by the global recession – resumed their upward trend until 2014.

The price driven investment downturn starting from late 2014 marked a notable change and essentially reversed a decade of cost inflation. A key element difficult to address with precision is to what extent the decline in costs experienced mostly in the 2014-16 period can be considered cyclical or structural. According to the IEA analysis, cost deflation experience over the last three years is the combination of both factors. The oil and gas industry relies extensively on outsourcing to service companies and leasing key equipment such as rigs or pressure pumps. Some of this equipment, especially floating rigs, includes complex engineering products whose supply is rigid. The investment cuts resulted in an unplanned underutilisation of the key equipment and a collapse of the rig rates. A similar decline was observed across the board in oil field service pricing. To what extent this is sustainable remains to be seen, as a certain degree of cyclical recovery in pricing already started to materialise in the first part of 2018, thanks to a modest pick-up of investment and rebalancing service industry capabilities. However, it also seems clear that the cyclical component cannot explain alone the level of upstream cost deflation experienced over the last years, and a deeper, more structural, transformation is also unfolding. Cost control and efficient project management received the highest priority across the industry, leading to a combination of management and technological innovation.

Overall, the IEA estimates that upstream costs for exploration and development worldwide will rise modestly by about 3% in 2018, although remaining 27% lower than the peak reached in 2014.

Figure 7 • Global Upstream Investment Cost Index



On the technology side, the industry is rapidly expanding its traditional use of digital technologies that enhance productivity and reduce costs. The digitalisation can affect the likelihood of drilling success and initial well flow rates, as well as ongoing reservoir operation through better analysis of data from 3D seismic and reservoir operations. Digital technology also leads to increasing automatisation and improved operational performance. There has also been innovation in mechanical and electrical engineering affecting well completion, and better design of both onshore gathering and offshore subsea infrastructure. Although it remains difficult to assess clearly the impact of modern digital techniques in upstream cost structure, all key players, both operators and service companies, are scaling up investment and capabilities in this sphere, anticipating in their strategy plans the achievement of important savings. In addition to "hard" technological innovation, soft innovation into enhanced management and processes also play an important role. The industry is adopting streamlined field layouts that in some cases enable modular development. There is a strong focus on the standardisation of equipment and components, which has had a major impact on costs, especially onshore. Management and procurement processes have been intensely assessed for cost-saving opportunities. A combination of relentless pressure from financial markets and enhanced uncertainty on future levels of demand, suggest that the efficiency drive is likely to remain a feature of major oil and gas companies.

Upstream costs in US shale activities

The cyclical, technological and management drivers of costs were all in play for North American shale as well, but with a somewhat different dynamism. Even in the period before the oil price collapse, North American shale was an exception to the general cost inflation. Upstream costs remained almost flat in the first part of the decade, thanks to a well-developed domestic service industry and a much more competitive environment.

While the key technology components, horizontal drilling and hydraulic fracking had been known for decades, their unique combination for shale development is relatively recent. As a result, there was a large scope for improving technology and management know how. Both the technological nature of shale projects and the industrial organisation have been conducive for rapid improvements. Shale development involves a large number of similar, individually small projects repeated after the other.

The development of US shale industry has been typically led by small and medium-size independent companies. Those companies typically have leaner organisations, a stronger appetite for flexible experimentation and higher profile risks. During the period of intense ramp-up, well completion intensity routinely exceeded the 100 wells/day level in various North American shale plays. This created scope for learning by doing, especially in longer lateral sections, multistage fracking, as well as the development of multi-pad drilling, which reduces the investment need into surface infrastructure, while increasing productivity.

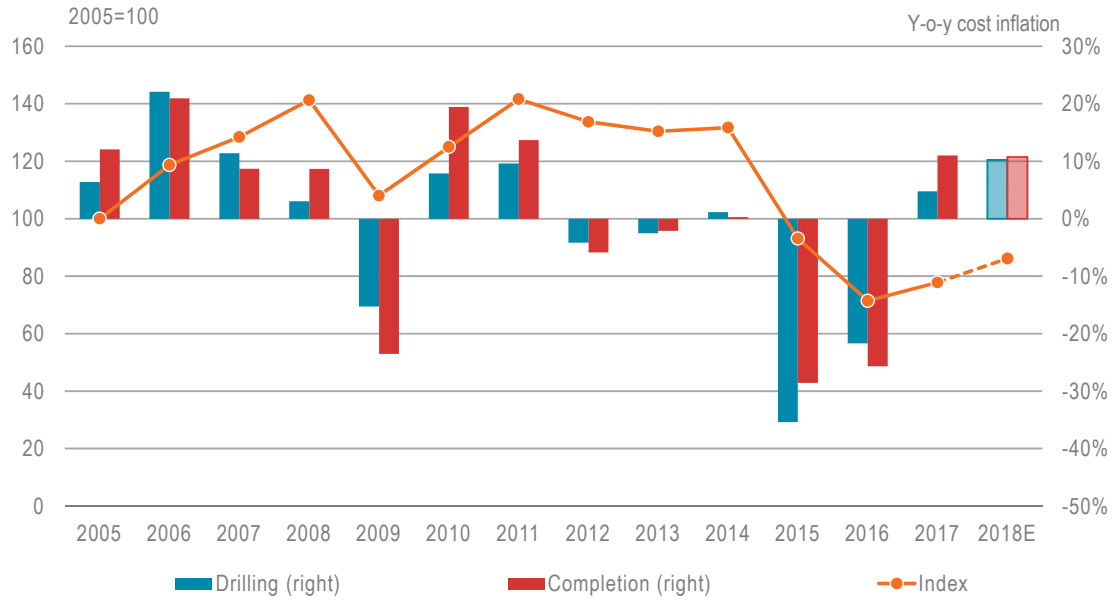
Nevertheless, during the rapid ramp-up phase there were clear signs of bottlenecks, especially in skilled labour and high capacity pressure pumping. In remote regions such as North Dakota, the supporting infrastructure struggled to keep up, a trend nowadays experienced even at larger scale projects in the Permian Basin. However, the impact of these bottlenecks was largely offset by learning by doing and technology improvements, even during the high oil price period.

The 2015-16 down cycle led to a very rapid decline in upstream shale costs. Throughout this period, overall costs declined by 46%, according to the IEA's Shale Upstream Investment Cost Index. A substantial proportion of this is perceived as structural and associated with the acceleration of the technological progress and learning by doing, especially regarding longer

horizontal sections and frack spacing. There is also a clear management priority to project streamlining and cost efficiency. Shale is also extensively digitalising, which is seen in the better targeting of shale sweet spots due to big data analytics, more precise fine-tuning of fracking as well as the application of robotics in drilling operations. However, as for conventional operations, it remains premature to assess to what extent the development and deployment at large scale of innovative digital technologies will affect shale cost structure.

Still, there are also clear indications of a cyclical component for two reasons: activity retrenched into sweet spots and lower development costs. In addition, as drilling activity declined and employment in the sector fell, labour shortages eased and suppliers lost their pricing power. As activity picked up strongly in 2017, these cyclical components reasserted themselves, leading to a re-emergence of cost inflation in the North American shale industry. We expect 11% of cost inflation in 2018 following a 9% increase in 2017.

Figure 8 • Upstream Shale Investment Cost Index



Financing oil and gas investment

Oil and gas are highly capital-intensive industries. At its historical peak in 2014, investment in the oil and gas industry reached 1% of global GDP. This share has declined somewhat since then, but oil and gas remained one of the largest absorbers of capital investment in the global economy. The oil and gas sector represents a substantial proportion of the stock market capitalisation in Europe and the United States and plays a major role in the lending portfolio of major international banks. The rollercoaster journey of oil prices over the last years has not fundamentally changed the way the oil and gas sector finances its activities, but there have been some notable adjustments.

In the context of the decarbonisation commitments of the Paris Agreement, an intense debate emerged on the need to redirect investment into the clean energy transition and avoid unnecessary stranded assets in fossil fuels. Campaigns and initiatives emerged to steer private investment away from fossil fuels through the divestment of shares and the influencing investment strategy decisions of major banks. These initiatives appear to be gathering momentum, and, increasingly, they are reflected especially in strategies of development banks. It has to be noted that most initiatives aim to discourage further expansion of coal consumption, but others explicitly target upstream investment, in particular related to shale and oil sands production.

While avoiding stranded assets and steering investment into clean energy are entirely legitimate considerations, this needs to be balanced with the continuous need to maintain the oil and gas supply that the world economy would still rely on also in a transition trajectory. A constraint on oil and gas investment can certainly limit CO_2 emissions: the world economy cannot burn fossil fuels that are not produced. However, if the supply investment trajectory is disconnected from the macroeconomic, technological, and energy policy drivers of demand, then the rebalancing of the markets to a low-consumption, low-emissions trajectory will take place through very high prices and possible shortages. Given the social and macroeconomic implications of very high energy prices, this is not likely to be a politically feasible energy transition trajectory. Given the abundance of high carbon intensity resources such as coal and heavy oil, the economic incentive to develop those might prove to be irresistible. While the record high LNG prices observed in the 2011-15 period did contribute to improving efficiency and the competitiveness of renewables, they also led to an upswing of coal use.

In addition to maintaining investment into upstream supply and infrastructure, the industry also needs to retain financial leeway to ramp-up investment, should an unexpected change in the supply-demand balance necessitate it. With the exception of US shale, investment normally cannot respond to short-term disruptions. Due to project lead times, those are managed through other energy security measures, including strategic stockpiles and fuel switching. On the medium term, however, the expansion of upstream investment to bring new supply to the market is a very important adjustment channel to market tightness. The availability of finance for timely investment is thus a key precondition for maintaining oil and gas supply security and executing a smooth, non-disruptive energy transition.

For conventional oil and gas, the large majority upstream investment has traditionally been financed on balance sheet from the cash flow generated by already producing assets. The combination of geological and geopolitical risks makes equity financing and intra-company portfolio diversification the preferred financial model for conventional oil. The industrial structure of the oil and gas industry is remarkably stable; the group of the largest oil companies has hardly changed since the merger wave at the turn of the century. A “typical” large oil company is a decades-old entity with a large portfolio of already depreciating assets providing a powerful internal cash flow. Outside North America, royalty regimes and production sharing agreements very often take most of the upside and downside of oil prices, so the investor’s exposure to oil prices is muted somewhat. There is also a high level of vertical integration into refining and retail, which provides smoothing to the company’s cash flow during oil price fluctuations. Because of their large legacy cash flows, oil majors almost never issue new equity. In fact, they on average return capital to equity markets. This makes them relatively immune to any divestment campaign, as a divested investor is likely to sell to another without such commitment, affecting only the secondary distribution of shares. While asset valuation is likely to be affected, the company’s investment budget is not.

Given the longevity of large oil companies and the stability of their cash flow, the primary expectation that capital markets have towards them is the dividend yield. All major oil companies maintain a sizeable dividend outflow (which is remarkably stable across cyclical fluctuations) to equity investors, with the company’s balance sheet used for smoothing. In fact, the supermajor independent oil companies (IOCs) have not cut their dividend since the Second World War. These dividend flows became exceptionally important for financial markets in the last few years, as level of yields provided by oil companies largely exceeded global average returns depressed by quantitative easing policies. Several major institutional investors, such as pension funds with ageing clients, have large cash outflows as well and want to maintain a share of their portfolio, which generates a steady income. Bonds have traditionally played this role, but in the last decade, bond yield incomes have collapsed due to unconventional monetary policy, raising the

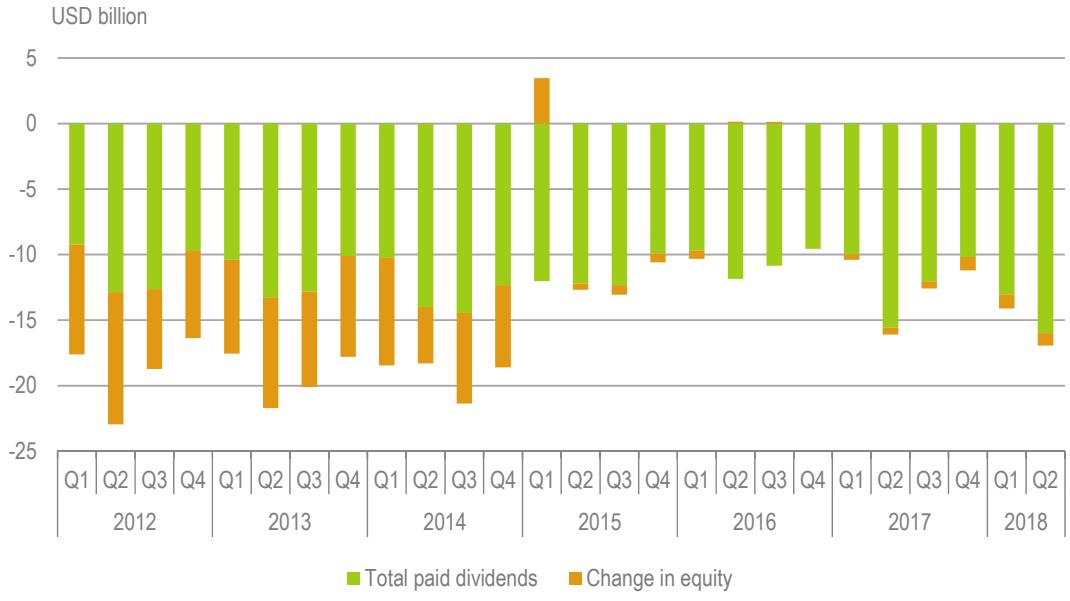
reliance on dividends from the financial sector. Theoretically, reducing dividends unlocks a large financial leeway for the oil industry to increase investment or maintain it during the downturn. In practice, there is a very strong management preference to maintain dividends reflecting shareholder expectations, so the realistic investment headroom has to consider dividend outflows.

The cyclical investment behaviour of the oil majors

Total dividend payments from majors remained practically unchanged at USD 10 billion to USD 12 billion per quarter during 2012-17, for a total of about USD 370 billion in the period 2012-17. However, the revenue plunge driven by depressed energy prices made companies reduce the amount of money returned to financial markets by reducing share buybacks.

As a combination of dividend payments and investment spending greatly exceeded operating cash flow, the companies took advantage of their favourable credit rating to ramp up debt in order to smooth out investment. During the harshest part of the oil price cycle (2015 and 2016) the oil majors borrowed over USD 100 billion. A significant proportion of the borrowing was associated with the Shell-BG transaction, and thus it was not used for new physical investment but, nevertheless, it ramped up debt played a major role in maintaining an acceptable dividend yield and mitigating investment cuts. Of course, this strategy is sustainable only if the downturn is temporary and cyclical. If for any reason, including policies or technology, developments significantly alter the long-term demand trajectory, the price downturn would be assumed structural in nature, and companies would eventually implement further measures in order to reduce their financial leverage.

Figure 9 • Redistribution of the capital market of majors



Note: The majors are BP, Chevron, ConcocoPhillips, Eni, ExxonMobil, Shell and Total.
Sources: Based on company disclosures and Bloomberg LP (2018, Bloomberg Terminal).

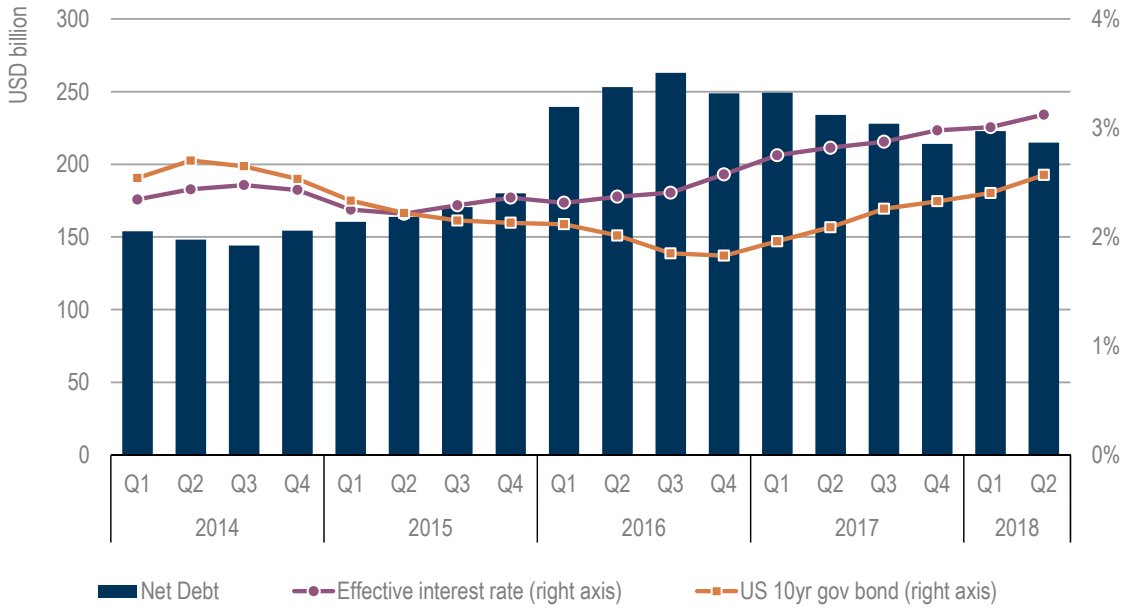
The emerging concerns about potential exposure to stranded assets due mainly to climate policies did not affect the oil industry's ability to maintain easy access to debt finance, either through corporate bonds or bank lending. There is no evidence of any major oil company having

experienced serious constraints to ramp up its debt. Further to generous dividends, companies benefited from the favourable leverage situation and portfolios characterised by the combination of already depreciated oil and gas assets and in several cases, by LNG operations that were better positioned also in an energy transition context.

The key concern from the financial sector appears to be the ability of the industry to reduce investment costs to the level, which enables them to maintain a positive free cash flow at moderate oil prices and without undermining their future production. These concerns were reflected in the cost of debt for oil majors nevertheless they did not lead to credit rationing. The average margin of major oil companies over long-term US government debt increased by around 120 basis points, although it remained at a favourable level.

The recovery of the oil price, coupled with a conscious management discipline on cost and investment spending, supported rapid improvement of industry's financial position from mid-2016. Operating cash flow increased by over 50% in 2017 and the increase of oil prices in the first part of 2018 led to a further improvement in the health of companies' balance sheets: first-quarter financial results showed the highest level of free cash flow since the first quarter of 2012.

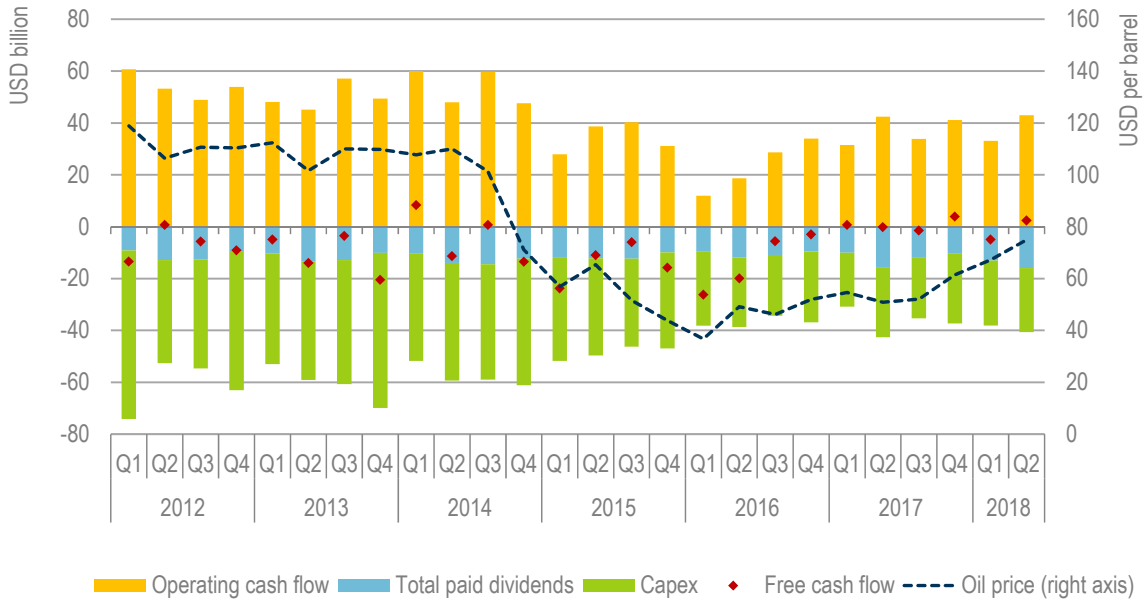
Figure 10 • Debt of majors and average effective interest rate



Sources: Based on company disclosures and Bloomberg LP (2018, Bloomberg Terminal).

However, the better financial conditions have not so far translated significantly into measurable investment increases. The industry continues to target two main priorities: 1) increasing the amount of money returned to investors through increasing share buybacks or rising dividends (Shell, Total and Chevron are just some of companies that recently announced such measures), and 2) reducing debt.

Figure 11 • Quarterly cash flow of majors and oil price



Sources: Based on company disclosures and Bloomberg LP (2018, Bloomberg Terminal).

Access to finance does not appear to be a serious constraint on a ramp-up of investment by the oil majors if tightening markets or geopolitical supply disruptions should necessitate it. Arguably, from a pure finance point of view, large oil and gas companies could have maintained a higher investment level in the first half of 2018, although this would have further stretched their financial conditions. It was the management determination to maintain cost discipline, lack of access to low-cost reserves and divestment – all energy transition-related stranded asset pressures that contributed to the continuation of subdued investment activity.

A scenario of higher investment needs is almost certain to be associated with higher oil prices. This would increase the cash flow generation of the existing production, although not proportionally, due to royalties. The stronger cash flow would directly increase the financial leeway for investment and it would have an indirect impact as well through the reduction of leverage and additional debt headroom for any given credit rating target. It is quite difficult to envisage a scenario where the IOCs would have to resort to issuing new equity. Nevertheless, tightening markets or supply disruptions would have an impact through equity markets and mitigating concerns about potential stranded assets. While the financial and social pressure to align oil and gas investment to the decarbonisation pathway is intensifying, it is important to highlight that this would not mean eliminating investment in oil and gas. On the other hand, reduced prospects for long-term demand would incentivise a shift in companies' portfolios aimed to minimise as much as possible long-lead projects and those with higher carbon content. Nevertheless, the compatibility of any IOC investment strategy to the low-carbon transition is not a question in isolation but it is relevant in the context of the overall supply side investment. If there are substantial and persistent supply reductions due to geopolitical reasons without a clear roadmap for resolution, such as in Venezuela and Libya today, this not only tightens markets, but makes any IOC investment strategy more likely to be needed to satisfy the residual demand of the low-carbon trajectory and thus not at risk of being stranded.

Most NOCs do not publish quarterly financial results, so it is difficult to track their financial reaction to the oil cycle. Nevertheless, some broad observations can be made:

- NOCs typically control low-cost reserves and have long lifetime assets with low decline rates, so their investment need is proportionally lower than their share of production. The main exception is Russia, due to the maturity of its asset base, which determines a higher capital intensity.
- Due to the low marginal cost production, NOCs tend to generate substantial rents, even at moderate oil prices. The standard practice is that governments earn this rent, but the accounting treatment of it can vary depending on whether the country's fiscal policy relies on taxes and royalties or dividends from the state-owned company. The taxes and royalties channel is more important for most oil producers.
- Some NOCs are listed in stock markets, with the government retaining a controlling state (i.e. Gazprom), while others are 100% state-owned (i.e. Saudi Aramco). The listed NOCs usually have corporate finance strategies comparable to IOCs and they rely on debt finance to a considerable degree. In fact, some of the oil companies with the highest corporate debt, such as Rosneft and Petrobras, belong to the state-controlled/stock market listed category. Due to past investment decisions mainly associated with strategic objectives to develop a major resource base, the state-controlled listed NOCs are in aggregate close to their leverage limit; access to debt in periods of lower oil prices is an issue for them. Other NOCs – primarily the 100% state-owned ones in the Middle East like Saudi Aramco – consciously avoided relying on debt and have a very substantial financial leeway to do so, should such a strategic decision be taken.

Overall, for most major oil producers, the key question for assessing the extent to which financing might be a constraint on investment is the reliance of the government budget on oil revenues. Practically all major oil producers levy substantial royalties on their NOC. The existing production could produce cash flow to support nearly any conceivable investment plan if the company could channel it to investment, but, more often than not, the government has a critical reliance on oil revenues and has to balance between leaving financial leeway to the company and other usually expensive social policy objectives. The trade-off between the investment ability of the oil industry and the financing needs of the state budget is publicly discussed in Russia, for example. While most oil-producing countries have started to implement structural reforms to reduce their economy's reliance on oil, these structural reforms tend to be gradual and politically challenging. Most major producers are likely to continue to face the trade-off between budgetary needs and oil investment for decades.

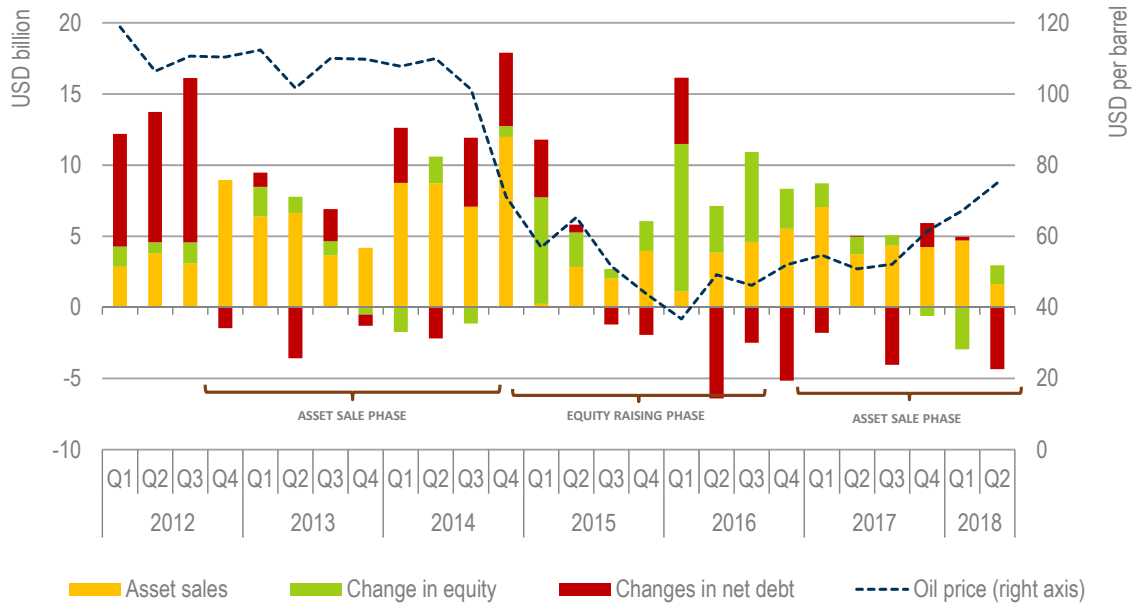
American shale is a disruptive new industry, not only from a technological point of view, but also from a corporate finance perspective. The industry was pioneered by medium-sized independent companies that typically do not have the balance sheet strength or the legacy assets of the supermajors. Consequently, the retained earnings-based financing model was insufficient for the massive investment needs of the shale ramp-up. Even for larger companies, the technological characteristics of shale constrain the use of retained earnings: due to the large decline rates, a shale well produces a meaningful cash flow to finance further operations only for a short time. On the other hand, the short project cycle enabled companies to rely on hedging on futures markets, an unusual practice in the conventional part of the industry. Hedging oil price exposures enables a higher reliance on debt. Growth prospects, rapid technological progress and modular project design facilitating learning by doing made the industry attractive for equity investors. As a result, the shale industry has had a much higher reliance on both new equity and debt issues.

The ramp-up of US shale from 2010 onwards coincided with the era of unconventional monetary policy and quantitative easing. There is no doubt that the industry strongly benefited from the unusual macroeconomic environment. Record-low interest rates triggered a "hunger for yield" and both pushed the cost of corporate debt to a record low and eased financing conditions as

well. Despite persistent negative free cash flow in the 2010-14 period, the industry had little difficulty attracting debt finance, mainly in the form of bond issues. Due to the higher leverage and more fragile financing position of shale independents, the cost of this was significantly higher than the IOCs, but still lower than the long-term average.

The 2015-16 downturn triggered considerable financing stress in the US shale industry. The industry's hedging activity was only partial, so cash flow generation was seriously hit with the downturn of oil prices. In some of the hotspots, large regional discounts emerged due to infrastructure bottlenecks. This discount compared to the widely traded benchmarks can have a major impact and be difficult to hedge. The downturn witnessed several major bankruptcies in the shale industry and especially in the first half of 2016 corporate bond markets essentially closed access for shale independents. However, the downturn was also associated with continuous productivity improvement and cost deflation and the future viability of the industry was not in serious doubt. Although at the cost of diluting existing shareholders, the industry was able to rely on equity markets through a series of IPOs to attract capital and reduce its leverage.

Figure 12 • Indicative sources of finance for US independents



Sources: Based on company disclosures and Bloomberg LP (2018, Bloomberg Terminal).

The reduction of reliance on debt during the downturn was not entirely voluntary. Due to their weak cash flow and systematic dependence on bond finance, the US shale independents were already highly leveraged before the downturn. Their high level of debt did not make it possible to smooth out the cycle by relying on bank finance of bond markets. The difficult access to credit made it imperative to rely on other financing channels, primarily equity. Finally, investment cuts and a relentless focus on cost management, efficiency and enhanced productivity improved the operating cash flow position of the industry to the extent that it regained access to credit markets, although the strategic drive to reduce leverage remained unchanged.

During the entire history of the US shale industry asset sales have played a major role in financing shale independents. At an aggregate level, asset sales are of course not a net-financing source; for someone to sell an asset someone else will have to deploy capital to buy it. However, given that US shale independents have played a unique role in pioneering and advancing shale technology, their use of asset sales is of a special interest. US shale independents would routinely

take a lease, access the geology, fine tune drilling and fracking techniques for the given shale play and act as anchor consumers to develop new pipeline infrastructure. Once technological fine-tuning and project management experience reduces the geological risks of the play, the leases became much more valuable, but also attractive for investors with less appetite for technological and geological risk. Selling assets to these players have become a major financing source for the independents who typically plough back the proceeds to finance the development of the shale acreage that they retained. The most important groups of buyers were the following:

- The first group of outside buyers were large importers, primarily from Asia, aiming to integrate vertically into US shale production. They bought often at inflated valuations and since then suffered a series of asset write-downs. After a period of initial enthusiasm, the group's approach has become much more conservative.
- In contrast, investments of the IOCs in US shale have gathered momentum in the past two years, especially the US supermajors, but also European companies have made major investments into shale, including the recent USD 10 billion acquisition of BHP assets from BP. With this model, they essentially plough back their legacy conventional cash flow into shale development. While, from a corporate governance point of view, they usually operate their shale activities on a stand-alone basis, reflecting its project management characteristics. From a financing point of view, they very much benefit from the large balance sheet and access to credit provided by an integrated conventional operation. The IOCs also have traditional advantages in developing upstream and midstream infrastructure in an integrated fashion.
- The past couple of years also witnessed a considerable degree of private equity interest in US shale and major assets were acquired by private equity players. Private equity is normally a high-cost funding source, but this is less of a disadvantage for short time horizon shale projects. Private equity investors are generally prepared to take complex geological and infrastructure risks and comfortable with high levels of leverage.

Given the developments of the past three years, access to investment finance does not appear to be a constraint for the ramp-up of the US shale industry. Although there is noticeable investment pressure to improve the cash flow position of the industry, companies have responded to this. The credit worthiness of the industry has improved; tightening monetary conditions have not yet translated into a structurally higher cost of debt for the industry. Both publicly traded and private equity markets have demonstrated their willingness to underwrite high quality shale assets. The often painful period of 2015-17 certainly shaped investor expectations, and there is now a much higher priority on discipline and a reluctance to undertake projects that are marginal. Moreover, with improving cost efficiency an increasingly larger proportion of US shale resources are considered intra-marginal in the context of global oil markets. There are serious and legitimate concerns about infrastructure bottlenecks and shortages of skilled labour slowing the industry's growth, but access to finance is unlikely to act as a break.

Upstream investment needs under various policy assumptions

Based on the IEA *World Energy Outlook 2017*, upstream oil and gas investment needs will be assessed under two sets of policy assumptions corresponding to the main *WEO* scenarios:

- The SDS describes the energy system's transition towards the decarbonisation objectives of the Paris Agreement. It also integrates the sustainable development objectives of providing energy access and tackling air pollution.
- The New Policies Scenario (NPS) serves as a policy baseline; it assumes only the policy measures that are already announced.

Upstream oil and gas investment in the SDS

In SDS, all policy levers are used to bring CO_2 emissions down. Given that carbon capture is not an option for very large hydrocarbon demand areas, such as transport for oil or building heating for gas, reducing emissions is equivalent to reducing demand by improving efficiency and shifting to lower carbon alternatives such as EVs running on low-carbon electricity. In the first stage of the transition, gas itself is a lower carbon alternative to coal and (to a lesser extent) oil. This provides support for gas demand, especially in currently coal-dominated systems. The non-climate objectives of SDS provide a slight compensation for oil and gas demand: liquefied petroleum gas (LPG) is a clean cooking fuel and gas plays a role in expanding electricity supply, especially in West Africa. As a result, SDS has a somewhat higher demand for these fuels than a pure decarbonisation pathway would, compensated elsewhere in the carbon budget. However, the impact of this on upstream investment needs is minor.

Global oil demand peaks around 2020 in the SDS, followed by an accelerating decline reaching 1.4 mb/d annually in the 2030. By 2040, oil demand is over 25 mb/d lower than 2017 levels, roughly the combined production of Saudi Arabia and Russia today. Global gas demand continues to grow until the mid-2020s and then reaches a plateau as efficiency and renewable electricity gather momentum. In the 2030s, global gas demand is around 500 bcm higher than today, a slightly less incremental demand than current Russian production. In the currently coal-dominated Asia Oceania region, gas demand remains robust in the SDS, in both China and India gas demand in 2040 is even higher than under the NPS, as gas contributes to reduce the environmental and climate impact of coal. This is relevant for the total investment need as the Asia Oceania region relies on long-distance gas imports, which have a substantial investment need.

The mixture of oil and gas changes from the current 60/40 in energy terms as the average product slate of the industry to gas representing the majority. This shift is well incorporated into the strategy of the industry and is unlikely to pose specific investment challenges. In fact, the IOCs have already made multibillion USD portfolio reshufflings towards gas and they play a major role in LNG that is critical to the contribution of gas in Asia. Nevertheless, the shift towards gas will pose a financing challenge: gas usually does not generate as strong intra-marginal rents as oil. A substantial proportion of global gas production is either sold in the North American wholesale market or sold to producing country offtakers at a regulated price. In both cases, its valuation is likely to be significantly below the oil parity in energy terms. Oil price indexation is still prevalent in Asian LNG markets, but very capital-intensive investments have to be made in order to reach that market. As a result, the average profitability of production declines and the amount of investment needed to support the cash flow of the industry increases, so the industry's ability to rely on internal cash flow deteriorates. However, this impact is mitigated by the shift of strategy in investing for declining oil demand.

Given the decline in oil demand and plateau in gas demand, investment is dominated by the need for replacing production declines in the SDS. Declines in post peak fields are determined by the combination of the underlying geology and the often-substantial investment committed to ongoing operations. As a result, identifying the underlying "natural" decline rate that would take place if the industry stopped investing is not trivial. The IEA estimates that in the absence of any capital investment, global oil production would decline by 45 mb/d by 2025 and nearly 80 mb/d by 2040 (from 93 mb/d in 2017). Note that, without additional investment, the fields that are still increasing their production would also be affected; together with the decline of light tight oil, this would create the fastest "no-investment" decline in the short to medium term.

In reality, the observed decline of post peak fields is substantially lower due to ongoing field management operations. Some of these are classified as operating expenses from an accounting point of view, but already-operating fields absorb substantial capital investment as well. Reservoir management is also affected by considerable technological progress, primarily through extensive digitalisation. Recent IEA analysis (*Oil 2018*) suggests that the average decline rate has diminished, despite the radical investment and operating expense cuts unfolding in the industry. This indicates impressive progress in the cost efficiency and productivity of reservoir management operations. Overall, in 2040, around 40 mb/d of new production capacity would be needed from conventional and unconventional sources to satisfy the demand of SDS. This is the combination of a 22 mb/d decline in demand from 2017 levels and a 62 mb/d decline in existing production between 2017 and 2040.

Decline and demand in SDS

New conventional field development investment needs are greatly influenced by prospects for unconventional oil and the prospects for enhanced recovery investment mitigating the decline of existing production. The investment structure and project choice is greatly affected by the oil market impact of climate policy: the relentless decline of global oil creates a structurally lower oil price trajectory. Thus, high-cost, capital-intensive prospects are likely to stay underground. Moreover, most jurisdictions, including the United States and Canada, have a high explicit carbon price in the SDS, which not only drives energy transitions, but also has a direct impact on high carbon intensity oil and gas operations.

The prospects for unconventional oil are mixed in the SDS. Tight oil greatly benefits from its short cycle production and hedged production both of which are well suited for an era of declining demand and technological uncertainty. Despite the current bottlenecks, the bulk of the pipeline infrastructure already exists in North America, mitigating stranded infrastructure asset concerns. Of course, the traditional advantages of tight oil, namely an innovative, competitive industry structure, prospects for intensive digitalisation and learning by doing remain in play in the SDS. Nevertheless, current tight oil investment targets the most cost effective and best-located areas in the huge (but diverse) North American resource base. These areas are increasingly depleted from the mid-2020s and the remaining US tight oil resource base can only be produced at higher costs. This impact of depletion occurs around the time when the policy-induced demand destruction has an increasing impact on pulling oil prices down globally. As a result, after a sharp ramp-up to 2025, driven by the current investment momentum and increases in oil prices, tight oil production peaks and declines to 6.4 mb/d by 2040. This is still higher than today, but far below the dominant expectations of the industry, indeed 2.8 mb/d lower than what the industry achieves in the higher carbon trajectory of the NPS.

Despite the limelight received in the stranded assets debate, oil sands remain relevant in the SDS. In fact, based on projects that are already under construction, oil sands production increases until the mid-2020s. Further, while no new large open-pit oil sand mines are constructed in the SDS, existing projects maintain a baseload level of production for decades to come. *In situ* upgrading using the steam-assisted gravity drainage technology is better suited to the energy transition, as these are smaller and more modular, and have shorter time-horizon projects. Depending on the cost efficiency, the projects might attract investment, even in SDS. Overall, oil sands production peaks early in SDS as the ongoing construction projects then gently decline due to the long lifetime of upgraders. Nevertheless, with its managed decline, it remains an important component of global supply security.

While it is the carbon intensity of the oil sands production that puts them in the limelight of the stranded asset discussion, the main investment driver in SDS is their overall cost

competitiveness in the context of abundantly-supplied oil markets. In SDS, oil sands production is subject to a high explicit carbon price at 140 USD/tCO_2 in 2040. This would have an impact on production costs, and, unless there is a rapid and wholesale reduction in the emissions intensity of production, project economics are adversely affected. In the case of an upgrader, a substantial proportion of the carbon footprint is associated with H_2 production and thus it is relatively well suited for the application of low-carbon technologies. Carbon capture is already applied in the natural gas based H_2 production in oil sands upgrading although today only around 7% of the total upgrading activity is affected. Several companies are investigating the use of increasingly cost-efficient renewable electricity, especially wind, to power oil sands operations. Nevertheless, applying these CO_2 abatement measures would increase the investment needs and production costs of oil sands and make them less attractive compared to low-cost and relatively lower-carbon-intensity resources. Investor expectations are also shaped by the fact that decarbonisation does not stop in 2040; SDS is followed by subsequent decades of further decline in oil demand. This will affect the willingness to invest in high carbon, long lifetime assets.

Investment into enhanced recovery potentially has a major impact in the decline of conventional production and thus into conventional field development needs. Most enhanced recovery technologies are relatively high cost and often have substantial lead times. As a result, the lower demand-lower oil price trajectory of SDS negatively affects most enhanced recovery technologies. Moreover, concerns over the depletion of resources often provide motivation for policy support for enhanced recovery. This will became much less relevant in case of declining oil demand and substantial resources staying underground. The major exception is enhanced recovery based on CO_2 injection. This is generally recognised to have strong positive synergies with the application of carbon capture. Appropriate monitoring and reservoir management can guarantee the environmental integrity of CO_2 reinjection, and with normal operations, even accounting for the carbon content of the incremental oil, there is a substantial climate benefit. Declining conventional fields that are suitable for CO_2 reinjection are often located in regions that contain clusters of refineries and petrochemical facilities that provide low-cost CO_2 capture opportunities. The widespread application of CO_2 pricing greatly helps CO_2-based enhanced recovery, as it lowers the cost of CO_2 for the upstream operation, potentially turning it to negative where operators pay for the injection/storage services in order to avoid carbon liabilities. As a result, SDS has a substantial expansion of CO_2-enhanced oil recovery, especially in the United States and China, mitigating the need for conventional field development investment.

Conventional oil withstands the worst of the adjustment to the energy transition trajectory. This is especially true for the high-cost, capital-intensive components of conventional oil, such as offshore developments. Projects at both ends of the maturity scale are affected: with declining oil demand there is much less need for further exploration, which affects recently opened upstream provinces like deep offshore in Latin America. Further capital-intensive investments into mature production became economically questionable, which has an impact in both Europe and Asia. On the other hand, the low-cost resource base of the Middle East and Eurasia performs reasonably well. The SDS does not assume a major change in the strategic objectives of the OPEC producers.

Despite the role of gas as a bridge fuel, the SDS trajectory has a major impact on upstream gas investment compared to the NPS, which is closer to the current strategic expectations of the industry. A substantial proportion of the US shale resource base stays underground in the SDS. The reason for this is that with very robust deployment of renewables and efficiency, US domestic gas demand declines over 15% in SDS by 2040 after a brief surge associated with replacing coal. As a result, the US gas system relies on growing exports as the dominant demand driver supporting upstream investment. While US LNG is a cost-efficient supply source in most

importing regions, the SDS demand trajectory, coupled with the resource base unlocked by unconventional and recent exploration success, leads to a very competitive international gas market scene. For example, in the SDS, EU gas import needs do not register a structural increase, despite the decline in domestic production, as renewables ramp up. As a result, any increase in US exports to Europe will take place in direct price competition with very low marginal cost Russian pipeline exports or would need to receive policy support motivated by energy security and diversification. Relentless price competition in international markets put a lid on US LNG exports, although it does remain a growth industry.

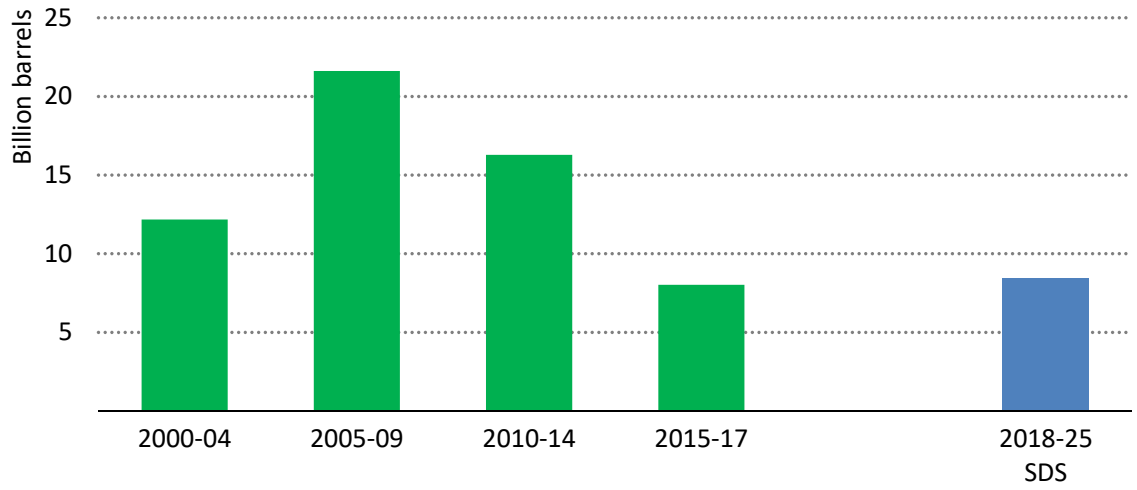
Likewise, the subdued demand trajectory of SDS has an impact on the growth of gas production from the recently unlocked resource bases in Africa and Latin America. Especially in the case of Africa, long-distance exports are instrumental in providing sound financial support for upstream investment. Both regions experience some growth, but markedly lower than what the geological resource base could, in theory, support.

Despite its large resource base, gas production in the Middle East also experiences a slowdown in growth in the SDS. Outside Qatar, the Middle East increasingly has to rely on reasonably high-cost gas resources. Iraq and Iran still have some very low-cost opportunities associated gas in the case of Iraq, and conventional supergiant development for Iran. However, in both countries, there are serious aboveground obstacles, and field development has been slow.

Russia remains a very large producer and exporter in the SDS. Despite the maturity of its resource base, Russia benefits from the fact that its new export projects are primarily oriented towards China, a market that sees substantial coal-to-gas switching. European exports are supported by declining EU production and the competitiveness of Russian gas benefiting from sunk cost pipeline infrastructure. The economic case for any new long-distance infrastructure supplying the European market is questionable in the SDS.

Overall, while the need for field development is substantially lower than in a high carbon trajectory, given the production profile of the already existing production and the likely field development composition, the oil and gas industry still needs to sanction new field development in the SDS.

Figure 13 • Annual new reserves sanctioned for field development in the SDS



Source: IEA Analysis based on *World Energy Outlook 2017*.

The annual average field development need is comparable to the industry's current field development activity. Note that this field development activity is the result of a historically

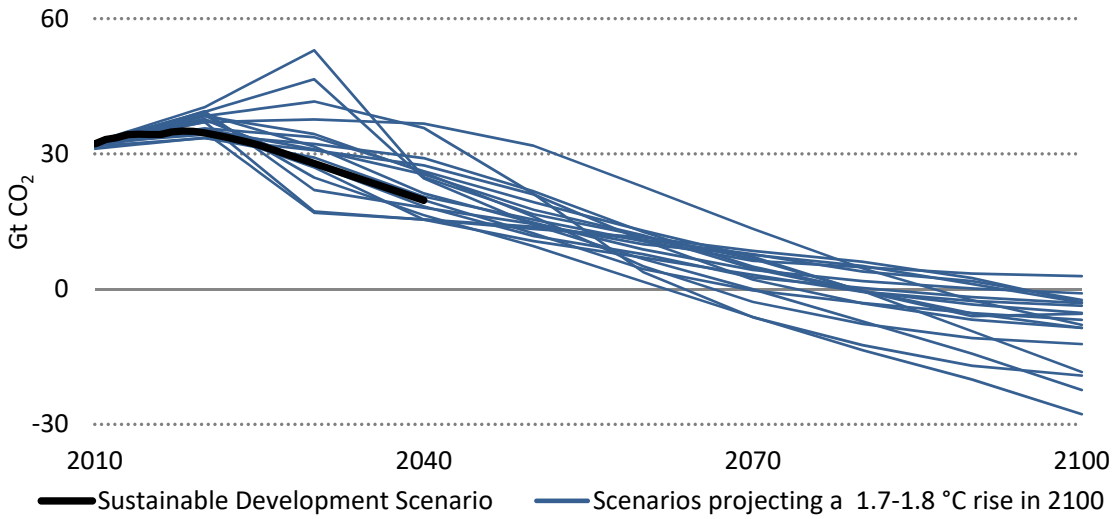
unprecedented investment cut and is structurally lower than the industry's performance in the past decade. There is little doubt that the industry has both the technical capability and the financial leeway to maintain this level of field development.

The SDS expects only a slight increase in upstream investment costs. The most complex, most difficult resources tend to stay underground, mitigating the technical drivers of cost inflation. Service sector costs recover somewhat from the cyclical depths of 2016/17, but subdued investment activity puts a pressure on service sector pricing. However, there is continued technological progress and increased digitalization of oil and gas operations. As the industry's strategy is reshaped by declining demand, a continuous priority on maintaining cost discipline is likely. As a result, the current investment in oil and gas upstream is in line with the SDS, not only in geological resources but also in financial expenditure terms as well. With the continuation of the observed investment activity, the transition to the SDS pathway could be executed without a major financial dislocation or stranded asset problem.

Oil and gas upstream in a Faster Transition pathway

The Paris Agreement did not specify a single energy-emissions pathway. While it is clear that any energy-emission pathway consistent with the Paris Agreement needs to achieve a global emissions peak in the near future and consequently fall to net zero emissions in the second half of the century, within these constraints there is a degree of flexibility for the energy system. Compared with the other assessed "well-below 2 degrees pathways" included in the Shared Socio-economic Pathways (SSP) database, the *WEO* SDS is among the most ambitious in terms of its emission reductions over the period to 2040.

Figure 14 • The *WEO* SDS compared to assessed "well-below 2 degrees" pathways



Note: Scenarios projecting a median temperature rise in 2100 of around 1.7°C to 1.8°C are those following Representative Concentration Pathway (RCP) 2.6 in the Shared Socioeconomic Pathways (SSP) database.

Source: https://tntcat.iiasa.ac.at/SspDb/. Figure shows energy-related CO_2 emissions, including industrial processes.

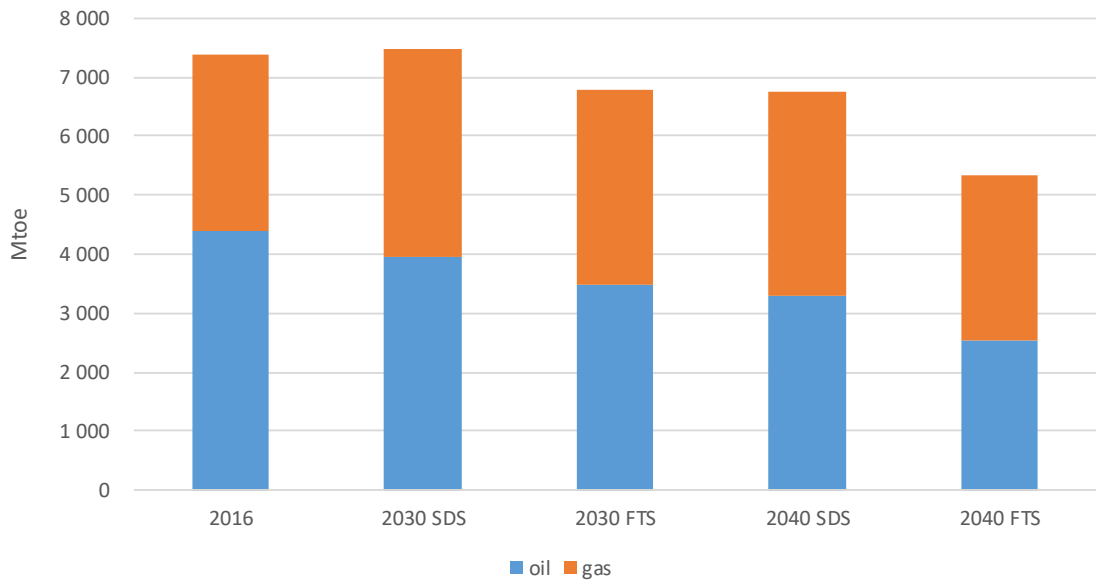
While the SDS is the IEA's benchmark "well-below 2 degrees" pathway, due to an interest in sensitivity cases, an FTS[2] was also created in the context of the German G20 presidency in 2016 and delivered to the Berlin Energy Transition Dialogue. The FTS entails an even more rapid, deep and comprehensive transformation of the global energy system primarily by large-scale

[2] This has also been referred to as the 66% 2°C Scenario.

systematic investments into renewables and rapid improvements of energy efficiency. It entails significantly more rapid decarbonisation and consequently a more rapid decline of fossil fuel use than the SDS through 2040. The SDS already extensively harnesses the "low-hanging fruit" decarbonisation options, so the additional acceleration of decarbonisation relies on the following main measures:

- The electrification of the transport sector is even faster and broader than in SDS. In FTS, more than a quarter of the global car stock would be electric by 2030. Electric car sales would need to scale up significantly beyond the current investment plans of the car industry into manufacturing capacity. Moreover, whereas in SDS the diesel engine remains dominant for trucks in the medium term, FTS would have a sizeable electric truck fleet by 2030.
- Wind and solar deployment would be accelerated above even that in the SDS. The global wind and solar fleet would expand by more than a factor of four by 2030, significantly reducing the need for conventional power generation. Such a rapid expansion of variable renewable production would require a wholesale transformation of the electricity system to unlock flexibility sources including transmission upgrades, storage deployment and demand response.
- FTS incorporates an ambitious nuclear uptake. World nuclear production would expand to two and a half times the current level by 2040, equivalent to adding more than four times the current European nuclear fleet. While several major energy systems, including China, India and the United States, have a pro-nuclear policy stance, the large-scale expansion of nuclear capacity would necessitate very strong financing measures as well as capability building in engineering and project management.
- FTS would require even more rapid progress than SDS in reducing fossil fuel use in difficult to decarbonise sectors like industry and buildings. By 2030, fossil fuels (primarily natural gas) would represent only a minority of building heat needs compared to their current dominance. Renewables also would make inroads in industrial energy use, by 2030 representing around 30% of industrial energy demand.

Figure 15 • Global oil and gas demand in SDS and the FTS



Despite the more radical technological transformation assumptions of FTS, the oil and gas industry still would have new investment needs into field development. Beyond 2030, when the

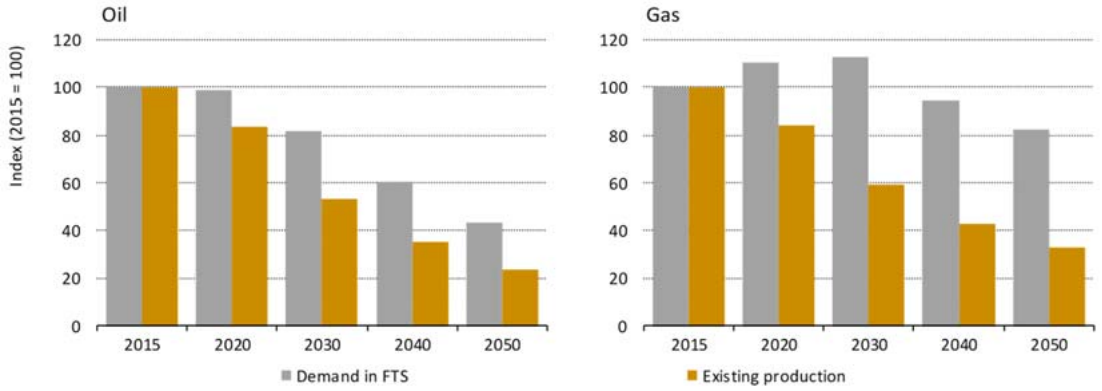
energy transition of FTS gathers momentum, global oil demand would decline by 3.5% annually and global gas demand by 2.5% annually. Undoubtedly, this would have a major impact on energy markets, especially compared to the growing oil and gas demand trajectory of the NPS. Due to demand destruction, FTS has structurally lower oil and gas prices; the difference is especially stark for oil, where the additional supply for the NPS would need to come from geologically and technically challenging and expensive fields. Global gas supply has a higher elasticity due to the scalability of especially non-conventional resources and the importance of fixed cost infrastructure investment to bring gas to import markets. As a result, the price impact of FTS is smaller for gas, nevertheless significant. Similarly, the impact of FTS on coal prices would be minor compared to SDS, as SDS already compresses coal demand to a level where global coal supply is very elastic.

Lower oil and gas prices, of course, affect the valuation of already producing oil and gas assets. Nevertheless, the same observations as made for the SDS also apply. Due to high marginal tax rate royalties and production share agreements, the financial impact is blurred. Moreover, the price trajectory of the three pathways is quite similar in the short to medium term, dominated by the current market dynamism. With the discount rate that private financial markets apply on oil assets, the longer-term divergence of the price trajectories has a minor valuation impact. The overwhelming majority of long lifetime production assets where a distant price trajectory makes a difference are financed from equity. High leveraging by companies in a fragile financial position is significant only for tight oil, where long-term price trajectories are not relevant. As a result, the likelihood of a spillover generating systemic financial instability is low. Moreover, given the cyclical fluctuations of oil markets, it is doubtful that the current valuation of oil assets reflects the high price trajectory of NPS, so a price trajectory in SDS or even FTS would materialise as a non-realised windfall gain rather than an actual valuation loss.

New exploration is less necessary and even economically challenged in FTS, unless it opens up cost-efficient new resources or benefits from proximity to major consumption centres and existing infrastructure. The amount of proven, but still undeveloped, resources that stay underground in FTS is around 300 billion barrels of oil and 30 trillion cubic metres of gas. The exploration costs already spent on discovering these resources would be stranded in FTS. This amounts to around USD 520 billion, the large majority of which is oil. This amount of stranded assets would need to be written off as the credibility of the FTS demand pathway gets stronger over the coming decades compared to around 40 billion asset impairments just by the supermajors in 2015- 2016. Note that from the point of view of an individual investor, the financial valuation of the reserve is not necessarily identical to the historical exploration cost due to market fluctuations.

Field development investment remains relevant in FTS, as even in that scenario the decline of global demand is lower than the decline of existing production. This field development investment need is optimised for a declining oil demand path, taking into consideration the production profiles of the respective upstream assets.

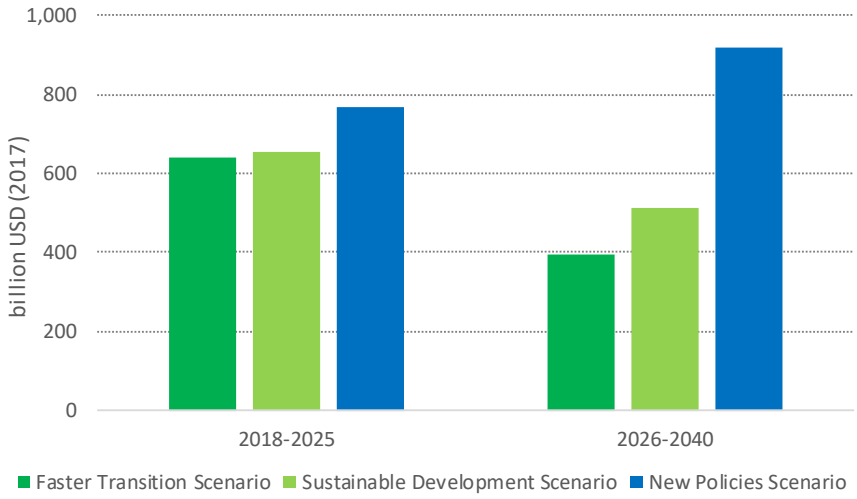
Figure 16 • Oil and gas demand, and decline of existing production in FTS



Source: Perspectives on the Energy Transition IEA 2017.

The overall oil and gas supply investment need in FTS would be around USD 450 billion annually until 2050, which is substantially below the current investment activity. This is over USD 100 billion less than the annual investment need of the SDS. The majority of the reduction would not come from the reduction of physical drilling and field development activity, as the need to replace declining production does not decrease proportionally to the changing demand pathway. Rather, due to lower oil prices and a less intense need for field development, upstream field development costs are projected to be lower in FTS than in the NPS, which would lead to substantially lower spending to support a somewhat lower physical activity.

Figure 17 • Investment needs till 2025 by scenario, compared to the long-term average



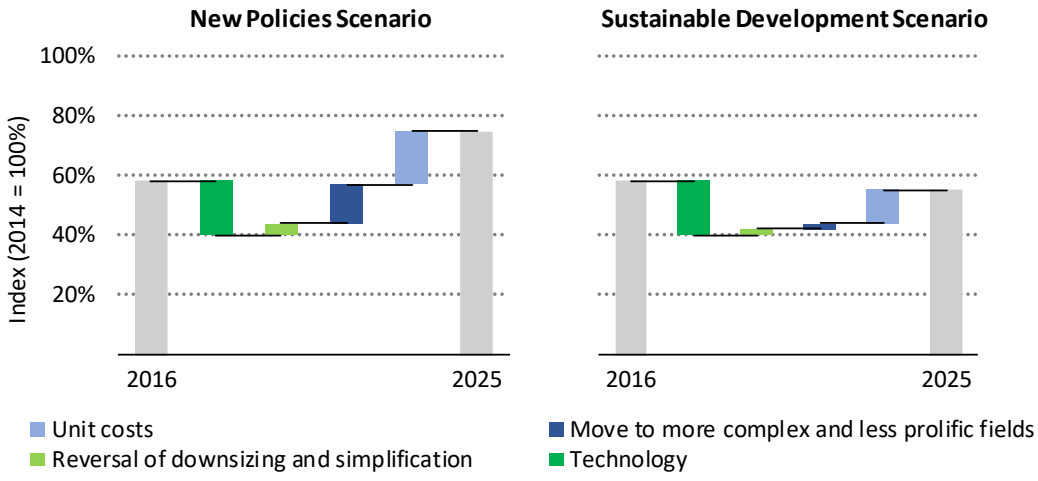
While the average annual investment need of FTS is substantially lower than the currently observed investment activity, this is due to averaging over the 2016-50 period. In the second half of the projection horizon, global oil demand would not simply be considerably smaller than today, it would also be declining rapidly. This of course has implications for both the field development need as well as the targeted reserve replacement ratio of the industry. In the medium term, the oil demand pathways are quite similar, so the investment needs differ only to the extent to which tail end production of new assets are affected by the longer-term outlook of a given scenario. Fields that are currently being developed will on aggregate be declining by the second half of the 2020s and so the longer-term oil demand pathway in FTS has a relatively small impact on the medium-term investment needs. Of course, a gradual transition based on credible

policy signals would eventually orient investment into the FTS trajectory, whereas in NPS, tightening oil markets would eventually draw market-based investment into the oil and gas upstream.

Sowing the seeds of the next boom-and-bust cycle?

While investment activity is broadly consistent with the SDS, this is not the case for policies affecting oil demand. In fact, at the recent demand increase of around 1.5 mb/d annually, the current oil demand dynamism is even above the NPS. Without policy measures going beyond those already announced, the *WEO* NPS would only see a slowdown in oil demand growth rather than a structural decline. By 2030, which is well within the time horizon of the upstream investment cycle, the NPS has oil demand at around 15 mb/d higher than SDS. This widens to around 30 mb/d by 2040. Even with a sustained ramp-up of tight oil, this demand trajectory means that around 16 billion barrels of conventional crude resources would need to be sanctioned for development every year over the next decade. There is no doubt that the current investment activity is insufficient for the NPS demand trajectory. If the current level of investment persists with the NPS policy mix and demand trend, the recent market tightening will continue. Tighter markets and higher prices lead to higher investment spending through spontaneous market adjustment. However, as described in the delayed investment case of the *WEO 2016*, due to the time lags inherent in conventional field development, the market would experience a painful boom-and-bust cycle if that should happen. Moreover, a rapid investment burst after a sustained period of underinvestment is typically associated with cost inflation as both human capital and service sector capability become scarce. In the NPS, the higher investment level and stronger reliance on complex, difficult projects to supply growing demand leads to a higher cost level.

Figure 18 • Drivers of upstream costs in the NPS and SDS



Source: IEA *World Energy Outlook 2017*.

Last but not least, if the NPS demand/SDS upstream investment discrepancy should persist for several years, it would make the SDS low-carbon transition financially far more disruptive. The coming boom-and-bust cycle would not be a "normal" cycle – the boom part of the cycle would generate massive investments into new and potentially long, lifetime production capacities just as an abrupt tightening of policy would offer the only opportunity to keep the option for climate stabilisation open. If the remaining carbon budgets implied by the temperature thresholds in the Paris Agreement are to be respected, the ramp-up of new production capacity would need to be

quickly followed by a demand decline even more rapid than the smooth SDS. This would lead to a considerable degree of financial stress. This risk was discussed in detail in the disjointed transition cases in the *WEO 2016* (for oil) and the *WEO 2017* (for gas), and it represents an order of magnitude higher potential stranded asset problem than the one associated with the SDS itself. In order to minimise the economic dislocation, it is essential than the industry's investment trajectory and the policy drivers of demand be consistent with each other.

Given the global nature of oil markets and the increasing globalisation of gas, it is not possible to attribute a direct link between any specific policy measure to a specific upstream investment project that would become unnecessary if an individual demand-side measure is implemented. Nevertheless, there is no doubt that demand-side measures in major consuming countries have a very large impact on the upstream investment need. For example, in the United States, the improving efficiency of the vehicle stock has had a similar order of magnitude impact on US oil imports as tight oil development, which has absorbed a capital investment of close to USD one trillion in the past decade. Similarly, while strong, SDS style climate policies necessitate less investment in the European gas system (as certain infrastructure projects became unnecessary). This pales in comparison to the lower upstream investment needs outside Europe that would be the indirect impact of lower European gas imports. The most important policy-induced demand-side investments that change the oil and gas market outlook in SDS are the following:

- For oil, the most important measure by far is vehicle efficiency. The reason for this is that under realistic assumptions, hundreds of millions of internal combustion engine vehicles will continue to operate for decades. The majority of transport sector related oil demand is in difficult to electrify sectors such as heavy-duty transport or aviation. Energy efficiency investment is primarily policy-driven. Efficiency standards or average emission performance standards drive investment into innovation and manufacturing capacity by the manufacturers, and this investment is eventually paid for by the consumers given that efficiency investments are priced into the sales price of the vehicle. A major challenge to be overcome is consumer preferences for performance and acceleration. Within the same vehicle category, efficiency investment is identifiable in the case of a hybrid drive train model of the same model. On the other hand, within the internal combustion engine models, usually the more expensive versions have a higher, rather than lower, consumption, due to their premium characteristics in terms of acceleration, driving performance and air conditioning. As a result, buying the more efficient car is often not a direct financial investment but rather downscaling consumer expectations, which faces behavioural barriers. Overall, transport sector efficiency investment between 2018 and 2040 averages just over USD 400 billion per year.
- Significant growth of electric cars is already locked in, even under the policies already in implementation (NPS). *WEO 2017* NPS projects 280 million electric cars in 2040 displacing 2.5 mb/d of oil. Unsurprisingly, the strong climate and environmental policy assumptions built into SDS lead to a greatly accelerated penetration of electric cars, and in the light duty segment, even trucks as well. Currently electric cars are around USD 6 000 more expensive than the comparable internal combustion model (for example, the electric VW Golf versus the conventional VW Golf). With this metric investment into electrification of transport was around USD 11 billion in 2017 and this investment reduced oil demand growth by around 30 thousand barrels/day. Investment into EV recharging infrastructure has also reached USD 5.3 billion in 2017 and should be seen as a key enabling factor for the spread of EVs. Today the bulk of the investment is financed from public budgets in the form of tax incentives and subsidies. Looking forward, the average subsidy level will decline and eventually drop to zero as technological progress improves the competitiveness of the electric drive train. In contrast, investment into the recharging infrastructure will need to

expand to nearly USD 300 billion in 2040 to enable the mass integration of EVs into the power infrastructure in the SDS. Overall, by 2040 EVs displace 9.2 mb/d oil in the SDS. This is considerably less than the displacement that the same number of EVs would imply today, since SDS also applies ambitious energy efficiency assumptions on internal combustion engine vehicles. As EVs replace more and more efficient conventional vehicles, the amount of oil displaced by an EV declines.

- In the building sector, Europe, and to a lesser extent North America, still consumes meaningful quantities of oil, around 1 mb/d in both regions, primarily in the form of low sulphur heating oil. In the SDS this is almost entirely eliminated. Given that remaining heating oil use concentrates in regions affected by lack of gas pipeline infrastructure, the replacement is primarily better for building efficiency, electric heat pumps and renewable heat. Due to the current dominance of gas in building heating, the policies of the SDS have a much bigger impact on gas demand and consequently, the global investment need of gas upstream. In the two temperate climate regions (North America and Europe) which dominate global buildings sector gas use, demand in buildings declines by around 25% in the SDS. The average annual investment needed in building efficiency and renewable heat between 2018 and 2040 in the SDS is just over USD 500 billion.
- Similar to building heating, the very large renewable electricity investments of the SDS primarily affect the oil and gas investment need through gas, rather than oil. Outside the Middle East and some remote regions, oil's use in power generation is already marginal. In the case of oil, the primary driver will be the expansion of solar in the Middle East–North Africa region. The region's natural abundance is obvious, and as air conditioning is the key electricity demand driver, there is a reasonably good correlation between solar production and power demand. Moreover, the climate of the region is also suitable for concentrated solar technology utilising direct irradiation. Concentrated solar power (CSP) plants can have built-in storage capability so they can complement solar photovoltaics (PV) supplying evening demand but also provide process heat for industry and desalination facilities. In the SDS combined solar (PV and CSP) production in the Middle East expands by more than a factor of 1 000 to reach 27% of generation in system that is much bigger than today. Around half of the growth contributes to supplying growing demand and the other half enables a radical reduction in the use of oil for power generation (-82% by 2040). Even with this growth, the average annual solar investment in the Middle East remains below the current investment spending on oil and gas in the region. Some countries in the region have successfully established solar policies and achieved some of the most cost-efficient solar contracts based on the combination of improving technology, better policy design and excellent solar resources. Nevertheless, the very rapid growth of Middle Eastern solar in SDS remains off track and will require additional policy measures. High-level policy targets need to be translated into effective auctioning mechanisms that mobilise investment. Grid infrastructure needs to be expanded, especially in remote desert regions where the most cost-efficient opportunities are located. At high penetrations of solar, the hourly discrepancy of air-conditioning load, which often peaks at around 5-6 pm when PV production declines, needs to be managed. Potential responses include flexible demand response from air conditioning, battery storage and an increasing use of CSP with heat storage. This is all technically and economically feasible but will require a consistent policy drive.

As the solar ramp-up reduces domestic oil demand, the market impact will primarily come through increased exports. There is no country in the MENA region that invests in solar in order to keep fossil fuels underground. In some cases, such as Oman, the resource base is mature and solar reduces or even eliminates the need for some high-cost marginal upstream investments. In most cases, however, the primary policy benefit from the point of view of the country is

increased export revenues from the oil that is displaced by solar domestically. As a result, the primary impact of Middle Eastern solar on oil upstream investment is outside the Middle East, as the very cost-efficient oil exports unlocked by solar drive some high-cost upstream prospects from the market.

Abbreviations and acronyms

BHP	BHP Billiton Ltd.
CIS	Commonwealth of Independent States
CNPC	China National Petroleum Corporation
CSP	concentrated solar power
EV	electric vehicle
FTS	Faster Transition Scenario
FID	financial investment decision
GDP	gross domestic product
GTL	gas to liquids
IEA	International Energy Agency
IOC	independent oil companies
LNG	liquefied natural gas
LPG	liquefied natural petroleum
MENA	Middle East and North Africa
NOC	national oil companies
NPS	New Policies Scenario
OPEC	Organization of Petroleum Exporting Countries
PV	photovoltaic
SDS	Sustainable Development Scenario
SSP	Shared Socio-economic Pathways
TANAP	Trans–Anatolian Natural Gas Pipeline
TAP	Trans Adriatic Pipeline
WEO	*World Energy Outlook*


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