Research Paper

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Oil and Gas Mismatches: Finance, Investment and Climate Policy

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Summary

This research paper analyses three developments that are combining to transform the outlook for investment in the oil and gas sector: price volatility, the changing financial environment and the impending strengthening of policy to mitigate climate change. It explores the connections and mismatches between the three developments and assesses their implications, especially those affecting the strategies of the 100+ diverse private-sector oil and gas companies, most of which are listed on stock exchanges and include the leading international oil companies (IOCs) or 'supermajors' responsible for about 10 per cent of global oil supply. These 'mismatches' also affect the expectations of those who invest in such companies through either loans or equity. In addition, there are implications for state-owned national oil companies (NOCs) and state-controlled listed companies – which together account for about 60 per cent of global oil production – as well as for the governments and people who depend on their revenues.

Oil prices

The international price of oil dropped dramatically in the second half of 2014. There is no consensus about whether the prices of near US$64/barrel (bbl) for West Texas Intermediate (WTI) and $65 for Brent will persist, and what the future trend will be. Without Saudi Arabia's balancing role (abandoned in 2014), prices are likely to be volatile over the medium term, requiring oil companies to become more resilient financially. The potential of US shale may cap any major price rebound that could normally be expected after a period of significant capital expenditure cuts by the industry. Meanwhile, lower prices reduce both the internal finance available from company cash flows and the revenues of governments dependent on NOC earnings. The capability for financial survival differs from company to company (and from government to government) over the short to medium term.

As regards the longer term, there is a mismatch between the development plans put in place before prices fell and the current, more uncertain outlook. Readjustment is taking place across the industry, whereby managements are focusing on low-cost production and reducing investment overall. That approach may limit the risk to investors of some oil and gas assets being 'stranded' if governments generally adopt stronger policies to reduce carbon emissions and hence the demand for oil, gas and coal.

The changing financial environment

New regulations impose limits on bank lending, including for oil and gas projects, through higher capital adequacy requirements. 'Shadow banking' and other forms of finance are developing (with less rigorous regulation), but there are mismatches between the level of sophistication of some borrowers and that of some financial innovators.

Policies and regulations on transparency, and voluntary commitments to the Extractive Industries Transparency Initiative (EITI) and to the Publish-What-You-Pay project, have increased. There are mismatches between these commitments and conditions for certain types of investment in some oil- and gas-producing countries.

Despite a period of extraordinary global liquidity, parts of the oil and gas industry were finding it difficult to obtain finance even before the oil price fell. This was particularly true of early-stage exploration and appraisal companies. The 'supermajors' among the IOCs have been able to borrow very cheaply but have suffered low equity valuations as investors were already disenchanted by returns from high-cost projects and acquisitions, which had to be written down with disappointing regularity. Some areas that have experienced growth – such as US shale – have benefited from the search by investors for yield in the low-yield environment created by quantitative easing (QE). The longer the effects of QE or similar programmes generate liquidity across developed countries, the longer will yields in those economies remain low. Meanwhile, riskier investments elsewhere, with higher yields, can be relatively attractive.

There is a mismatch between the current yield environment and what is to be expected when monetary expansion ends: yields in oil- and gas-exporting countries will need to rise to compete with those that will become available in developed countries with less political and jurisdictional risk, particularly the US and Canada. Private-sector finance for projects in some oil- and gas-exporting countries will be held back unless those countries improve the terms that they offered during the period of loose money and high oil prices. Investors will need to reappraise the risk/yield balance of most investment opportunities.

Stronger climate change policies

There will be a profound mismatch between the investment opportunities available for oil (and to some extent for gas) if enough governments adopt 'strong' policies – designed to limit to less than 50 per cent the probability of global warming exceeding 2°C – and the investment opportunities available if those policies are not adopted.

Uncertainty about the strength and speed of the development of climate change policy creates the 'Janus risk'. If 'strong' policies are widely adopted soon, a significant portion of the proven and probable reserves of oil and gas (and coal) will be left in the ground and the expenditure on finding and developing them will have been wasted. Conversely, if climate change policies continue to be too weak to limit the probability of global warming exceeding 2°C to below 50 per cent, growth in an 'old-style' carbon-dependent world economy would require continued investment in oil and gas supply. The mismatch between climate risk and supply risk results from the consequences – possibly unintended – of interactions between government policies, industry investment plans and how the financial community views the credibility of those plans.

In the longer term, the development of stronger and more global climate change policies will have an impact on demand trends and put at risk not only some investments in oil and other fossil-fuel supplies, but also investments in power stations, factories that make 'gas-guzzling' vehicles, buildings that do not conserve energy and so forth. The economics of such investments will remain uncertain until the scope and content of climate change policies are clarified.

Conclusions

Financial strategies will have a critical part to play in dealing with the above-mentioned mismatches in the short and medium term. In the longer term, the forthcoming climate negotiations in December 2015 may not themselves generate strong policies but are likely to boost the momentum for policies that will depress global demand for fossil fuels. The political commitments of the US and China will be key factors in this process. Strong climate change policies would drive a wedge between the costs incurred by consumers to use energy (or to avoid using it) and the prices that fuel producers can charge, thereby increasing the differential. Although the age of cheap oil production may not yet be over, the age of oil being cheap to use is coming to an end.

Introduction

These are difficult times for investment in oil and gas. This paper analyses three developments that are combining to create what we term 'mismatches' between the channels for finance and the opportunities available for investment in oil and gas:

- The fall in oil prices since mid-2014;
- The changing financial environment, in which bank lending is becoming more restricted and the period of easy monetary policy is expected to come to an end, affecting the yields sought by investors; and
- The development of policies to mitigate climate change, which pose a longer-term challenge to the oil and gas sector.

The mismatches cannot be dealt with solely by either the providers of funds or the investors in projects, nor can any one set of problems be solved without taking into account the solutions for others. Companies that invest in projects and try to adapt their operations to the new price environment and longer-term outlook cannot ignore the financial community's expectations for the industry as a whole, as well as for individual companies. The providers of finance will need to reappraise the risks resulting from choices made by companies in the light of the alternatives for deploying finance elsewhere in the energy sector and/or in the national and international economies.

Oil Prices: Another New Era

The collapse

Recent developments have changed the outlook: uncertainty has replaced 'business as usual' as the new benchmark.

Between June 2014 and January 2015 the average price of Brent crude for front-month delivery plunged from US$115.7/bbl to US$45.19/bbl – a fall of some 60 per cent. By 10 June 2015 it was hovering between US$64/bbl and US$65/bbl. The obvious explanation is that in the absence of any intervention by Saudi Arabia or OPEC to restrain production, a surplus of supply over demand had rapidly developed.

In 2013–14 US production grew by 1.6 million bbl/d (the equivalent of nearly 2 per cent of 2013 world consumption). A further 1 million bbl/d increase is forecast by the US Energy Information Administration (EIA) for 2016, to be sustained until 2020.[1] Throughout 2014 consumption in the OECD fell, offsetting nearly half the growth outside it; OECD inventories rose, and by April 2015 industry stocks were more than a third above the average of the range of previous inventories.[2] Saudi Arabia tried, but failed, to persuade other OPEC exporters, as well as non-OPEC exporting countries, to cooperate in restricting production. Oil Minister Ali al-Naimi then made it clear that Saudi Arabia intended to defend its market share, and on 23 November OPEC formally decided not to change its production quotas – a decision repeated at its meeting in June 2015.

The precedents

There have been precipitous price collapses in the past. Demand fell following the second oil shock (1979–80, when prices more than doubled in real terms) and during the subsequent recession, leaving producers with a structural capacity overhang. There were steep but short-lived falls in 2008 following the world economic crisis and in 1998 after the collapse of Asian demand (caused by the 'Asian flu' recession). In 1986 there was a price collapse similar to that of 2014: at that time, Saudi Arabia stopped absorbing the main impact of lower demand and prices halved, thereby changing the rules of the game for nearly 20 years. Until 2003 prices remained in the range of US$25–30/bbl (in 2013 US$) – interrupted only by the 1998 dip – as Saudi Arabia and OPEC tried to regulate the supply from the excess production capacity that had resulted from the earlier fall in consumption. Over time, the excess capacity was eroded as demand grew, and the oil price jumped to more than US$100/bbl in 2008. That price level was sustained until 2014 by a combination of strong Chinese demand and supply disruption in countries affected by the 'Arab spring', events in Gaza and the Ukraine crisis.

[1] EIA, *Short-term Energy Outlook*, June 2015.
[2] IEA, *Oil Market Report,* June 2015.

The new rules of the game

Before the oil price fall of 2014, the International Energy Agency (IEA), the EIA and the OPEC Secretariat all forecast rising spare capacity in reference cases for the medium term and flat or slightly declining real prices.[3] Those forecasts implicitly assumed that Saudi Arabia and other major exporters would continue to cooperate to stabilize oil prices to the extent that they were able. The situation has now changed. Today the oil market faces a commodity cycle in which there are not enough exporting countries willing to cut production to support prices. Saudi Arabia will not act alone, while agreement with the other OPEC exporters is unlikely as long as Iraqi production falls massively short of its potential. Meanwhile, Iran expects sanctions to be eased; and Venezuela increased oil production in 2014, despite the disarray of its national economy.

Since May Brent crude has traded in the range of US$60–65/bbl, but the uncertain conditions have not changed significantly. On the downside, production in Venezuela, Libya and Iraq, as well as Saudi Arabia, continues to edge upwards. The EIA predicts that US production will continue to grow throughout 2016,[4] but for how long and at what rate depends on how diverse shale producers respond to lower prices; currently, some are deferring well completion, others are cancelling new drilling in less productive areas, and others still are driving down the costs of their suppliers. Many have hedged forward and secured financing for the immediate short term. In Asia, demand remains sluggish. On the upside, there is a possibility that global demand will respond to the lower prices. Whether that happens will be determined by a combination of broader economic developments, macroeconomic policy and consumer behaviour in the main markets, particularly China. Meanwhile, on 10 March 2015 traded options for 12-month delivery Brent indicated only an 18 per cent probability that its price 12 months ahead would be less than US$50/bbl and a 30 per cent probability that it would exceed US$70/bbl.[5]

Five years ahead

In the medium term, the uncertainty is set to increase. The IEA has estimated that surplus oil production capacity was 3.5 million bbl/d in 2014 and will increase to 4.6 million bbl/d by 2019.[6] Those estimates point to continued downward pressure on prices; however, they do not take into account the possible effect on demand of the lower prices since mid-2014. In late 2014, Citigroup published an analysis that repeated the conclusion of its 2012 analysis: namely, that the five-year-ahead fair market value of Brent crude (absent disruptions and one-off events) remains in the range of US$70–90/bbl.[7] That estimate is based on conclusions, all similar, from three different models and cost curves of private-sector oil development projects. The next projections from the main agencies (due in autumn 2015) will be up against this continued uncertainty and will have to try to predict a somewhat different commodity cycle from its predecessor. The IEA's *Medium-Term Oil Market Report 2015* represents the first attempt to assess the new outlook.[8]

[3] IEA, *World Energy Outlook 2014*, November 2014; EIA, *International Energy Outlook 2014*, September 2014; and OPEC Secretariat, *World Oil Outlook 2014*, November 2014.
[4] EIA, *Short-term Energy Outlook*, March 2015.
[5] IMF, *Commodity Price Outlook & Risks*, 10 June 2015.
[6] Munro, D., '"Effective" OPEC spare capacity', *IEA Energy: The Journal of the International Energy Agency*, 2014.
[7] Morse, E. L. et al., 'Goodbye Triple-Digit Oil', Citi Research, 21 November 2014.
[8] IEA, *Medium-Term Oil Market Report*, January 2015.

The state of the world economy will be the main determining factor for oil demand (at a time when China is no longer in its infrastructure build-up phase and is experiencing slowing growth). Other factors will be lower energy and oil intensities as a result of investments made to reduce consumption during the period of high prices (2008–14); reactions to the low prices of the current period; and expectations about future climate change policies. With respect to supply, projections will have to incorporate the impact of US shale (with its variable production potential and sub-US$60 position on the cost curve), the high levels of oil in storage, the possible return of low-cost Iranian production and the continued development of Iraq's potential.

Climate change: the new long-term reference

Beyond five years, projections will increasingly need to look at the impact of climate change policies that develop from the December 2015 Paris negotiations. Those policies will be designed to restrict demand for fossil fuels in proportion to their carbon content; thus they will lean most heavily on coal and least heavily on gas. At the same time, market intervention will support renewables and low-carbon fuels, particularly in electricity generation and (through the promotion of electric vehicles) transportation. Models of the effect of those policies are discussed below, in the section on climate change policies.

Gas

The gas-pricing systems of the principal consuming countries are changing too, although transport costs are responsible for strong differentials between gas prices in the main importing regions. In the US, natural gas prices are low because the rapid growth of shale gas production has reduced imports. In Asia, historically high prices are weakening. Links to oil prices are looser because of uncertainty about demand (especially in China) and long-term competition from Russia, which is pushing ahead with several international pipeline projects. In Europe, imports arbitraged through the UK and the other open markets of northwestern Europe are weakening traditional contractual links to oil prices. Local pricing continues to play an important role (60–70 per cent of global gas consumption is supplied from local production, whereas some 70 per cent of global oil consumption is supplied by imports) because the cost of international pipelines and liquefied natural gas (LNG) infrastructure hinders trade expansion.

Indeed, investment in expanding gas trade is risky. Government interventions in the power sectors of importing countries define the size of the market for gas in power generation after policies on coal, and nuclear and renewable energy have been applied. In the EU and the US, regulations requiring infrastructure owners to give open access to shippers may inhibit the sharing of risks between importers and exporters through long-term bilateral relations – and the same could apply in Japan as that country introduces similar regulations. Investment in gas infrastructure will become more risky over the 30–40-year lives of such projects, and traditional infrastructure financing based on long-term contracts with stable tariffs and volumes will not be not sufficient to deal with those risks.

Implications for investors in oil and gas

In the short term, a scarcity of cash may persist for some time. In the longer term, there may be another investment cycle. A shock disruption cannot be ruled out, although many indicators point to prices closer to today's levels than to US$100/bbl; and low prices may persist when so-called decarbonization policies take effect on consumption. All this uncertainty suggests that investors will demand high returns, so companies will require financial strategies at least as powerful as their operational ones; indeed, there may be adjustments between those companies that can combine resilient finance with good projects and those that have mismatches of one kind or another. Investors will look for company strategies that are attuned to the new game rather than the rhetoric of the old. In the US shale sector especially, there may be consolidation to bring good assets to financially strong companies as weaker ones face refinancing – a move that investors would welcome. As the US shale sector matures and its prospects stabilize, there is likely to be a shift away from high-yield bond financing to a more balanced funding structure.

The Changing Financial Environment

Mismatches between finance and investment opportunities

Financing for investment in oil and gas is affected by changes in policy and practice, which inevitably create mismatches between the mechanisms for linking funding sources and opportunities for investment. The collapse in oil prices since mid-2014 has reduced the industry's capacity to self-fund its expenditure. Companies have responded mainly by cutting expenditure (to varying degrees) rather than dividends. For some companies, new borrowing becomes costlier and more difficult when they are de-rated by the credit rating agencies. Over the longer term, the risk–reward balance changes.

The progressive tightening of banking regulation (Basel III and related agreements) in the G20 member countries since the financial crisis of 2008–09 has reduced the leverage potential of banks. As a result they have less capacity to lend in general – not just to the oil and gas sector. Restrictions include higher capital adequacy requirements (i.e. a larger amount of capital must be held against loans made), tighter lending rules, limits on proprietary trading (i.e. trading on the banks' own accounts as principals – the 'Volcker rule') and increased transparency. Some banks may still be carrying bad debt, with the value of their loans marked down in response to lower expectations of prices and revenue. Other providers of loan and even equity finance have emerged, including private equity, sovereign wealth funds, large pension funds and insurance companies. Those institutions are less regulated and their activities less transparent, which presents both an opportunity and a risk. Small and medium-sized companies will need to become more sophisticated financially to survive and thrive in this environment, but non-bank finance is likely to expand and facilitate the restructuring of the oil and gas industry.

As in other industries, the oil and gas sector is affected by policies that increase transparency in financial activities such as hedging, making payments to governments or contractors and awarding contracts. Measures to this end include the Dodd–Frank reforms and the Foreign Corrupt Practices Act in the US, the Directive on Extractive Industries in the EU, and the Unfair Competition Prevention Act and EITI in Japan. As a result of such measures, it has become very difficult – or even impossible – for OECD-based foreign companies or lenders to operate in some countries.

Meanwhile, the persistent extraordinarily high levels of liquidity supplied by central banks in the US, Europe and Japan have depressed interest rates and yields generally, sending investors elsewhere in search of higher yields. Only some sections of the oil and gas sector have been able to benefit from the shift in investor focus. Thanks to its strong growth characteristics, US shale has been a beneficiary, while traditional exploration and appraisal companies have suffered from the lack of investor interest. When the loose-money programmes are wound down, interest rates will rise across the board. In response, oil and gas investments will need to offer higher returns. Many oil and gas exporters in developing countries will have to improve fiscal terms and reduce 'above ground' risks to balance the attraction of improved yields in countries with stable physical and contractual jurisdictions like the US. In effect, this will be a reversal of the trend prevailing during the era of high oil prices.

Equity investors tended to be unenthusiastic about the oil sector even before the oil price fell. Since 2011 a five-point gap has emerged between market valuations for energy companies and the S&P 500, as returns on capital have fallen in the sector. The combination of worsening terms, costs going out of control, projects falling being behind schedule and acquisitions not creating value for shareholders led to the sector being de-rated and companies having to seek alternative means of finance. (Royal Dutch Shell, for example, used a master limited partnership (MLP) to fund a pipeline at 23 times earnings, in contrast to nine times earnings for the company as a whole.) While larger companies are able to find alternative funding, early-stage exploration and appraisal companies, for which equity is the appropriate funding route, are left without access to finance.

As a result, there is increasing differentiation between oil and gas companies and between oil- and gas-exporting countries. Some companies and countries are much better placed than others to deal with the mismatches. A period of adjustment can be expected in which financially strong companies will acquire strong assets currently belonging to weak companies that are financially unable to exploit them. High-cost and high-risk projects will be abandoned or deferred. Companies whose existence relies on such projects will be taken over or broken up, and countries that depend on them for future development will have to revise their strategies.

Self-financing problems

Cash from operations provided 75–80 per cent of the cash used by 120 non-state oil and gas companies worldwide during the period 2009–11.[9] The 2014–15 oil price collapse reduced companies' cash flow and their ability to finance investments. Private-sector companies were already being criticized in the financial markets for undertaking high-cost projects and failing to execute them either on time or within budget. Meanwhile, rates of return were falling. Today many of those companies are scrambling to conserve cash by cutting current costs and capital expenditure programmes. A large number of projects are being deferred because of the effects on their economics of uncertainties about oil prices. Listed companies are having to find a balance between keeping their commitments to the dividend, executing their spending programmes and securing access to new external finance.

According to an estimate by industry consultants Wood Mackenzie,[10] a price of US$60/bbl for Brent in 2015 would require a 35–40 per cent cut in capital spending by 42 listed companies (excluding small-cap companies), while US$80/bbl would require a cut of some 20 per cent, to prevent the debt leverage of those companies from increasing. Many companies claim that they based project economics on US$80/bbl before the price collapse; if that is the case, financial constraints rather than project economics alone account for the estimated 20 per cent cut. The difference between those constraints and the proportion of capex that is notionally flexible varies widely from company to company. For some, Brent at US$60/bbl would require cancelling or deferring committed projects and/or accelerating disposals. It should be noted that the above estimates are fluid, as all companies are pressuring both the service industries and suppliers to reduce prices and costs; as a result, suppliers are laying off staff and dismantling some of their support investment.

NOCs are undergoing the same process as the private sector but face additional challenges. They cannot expect governments that are highly dependent on oil revenues to ease their fiscal and profit 'take' (as the UK has done for North Sea operators), although in some cases the burden of subsidizing

[9] EIA, *Financial Review: Third-Quarter 2014*, December 2014.
[10] Wood Mackenzie, *Oil Prices: Company Spend Cuts Needed in 2015*, December 2014.

local consumption has been reduced. Few governments are in the same situation as Saudi Arabia, the net foreign assets of which would cover 24 months of imports.[11] Furthermore, the NOCs' bargaining position *vis-à-vis* private-sector investors is worsening for the reasons, discussed above, related to the loose monetary policy pursued by the major developed economies and the tighter credit conditions under today's more rigorous financial regulations.

Table 1 below shows cuts in investment plans announced by companies and reported in the press as at the end of March 2015. Reports are general; time periods and baselines are not necessarily specified and exact comparisons are not possible.

Table 1: Cuts in company investment plans

Company	Capex cuts reported as of end-March 2015
BG	-30%
BP	-13% to US$20bn in 2015 from US$22.9bn in 2014 (guidance had been US$24–25bn in 2015)
Chevron	-13% to US$35bn in 2015
CNOOC*	-35% in 2015: exploration -21%, development -67% and production -10%
ConocoPhillips	-20% to US$13.5bn in 2015
Continental Resources	From US$4.6bn in 2014 to US$2.7bn in 2015
ENI*	-17% to 48bn in 2015 (plus dividend cut)
ExxonMobil	-11.6% to US$34bn in 2015; 'a little less' in 2016–17
Gazprom*	-40% in 2015
NNPC*	-40% in joint ventures in 2015
Pemex*	-15%
Pertamina*	-50% in 2015
Petrobras*	-25% in 2015
Petronas*	-15–20% in 2015
Rosneft*	-30% to US$23.3bn in 2015
Royal Dutch Shell	-US$15bn 'over the next 3 years': phasing not specified but 'steady in 2015' (new figures expected when the BG deal is finalized)
Saudi Aramco*	-20% in 2015: delaying Khurais development and Red Sea exploration
Statoil*	-10% in 2015

* Denotes state-owned or state-controlled company.
Sources: Company announcements reported in press January–March 2015.

[11] IMF, *Saudi Arabia: Article IV Consultation – Staff Report*, Press Release, September 2014.

Structural problems of the NOCs

The NOCs' approach to financial markets is determined by the extent of their financial independence from their national governments (in turn dependent on oil revenues for budget funding, foreign-exchange reserves etc.); and the degree to which their national economies are diversified. Higher prices in recent years enabled many governments to build up substantial fiscal and foreign-exchange reserves, even as domestic spending and imports increased. Those reserves enable some countries to allow NOCs to continue to invest; but for many such companies, that activity is rapidly becoming a challenge, as Table 1 shows.

Some state-controlled companies such as Statoil, Petrobras and Rosneft are incorporated like private companies and are listed on stock exchanges outside their home country. They have private-sector shareholders, but controlling shares remain in the hands of the government or government agencies. Such companies have direct access to financial markets, but must preserve the share of the state when raising new equity. A controlling state shareholder can none the less influence spending and financial plans that affect the country's credit. Even a listed NOC can never be as financially independent as a private-sector company, because its financing influences the country's creditworthiness, while its dividend policy affects the government's budget planning and vice versa. A company whose stock is listed but is majority-owned by government agencies may require explicit government and parliamentary approval for its budget, treasury approval for borrowings[12] and parliamentary approval for any borrowings in excess of its budget.

However, listed government-controlled companies are subject to the reporting requirements and regulations of the countries in which they are listed; these limit the scope for their controlling government shareholders to interfere in their commercial and operational activities. The transparency required for listing should support management, efficiency, accountability, cost control and more effective policies on content and procurement, as well as lowering the risk of corruption.

In international financial markets, NOCs compete against private oil companies without the national advantage that they enjoy at home. They must reassure investors about risk and reward – a task that is more difficult today than it was during the period 2010–14. Investors prefer proven geological prospects with low-cost implementation, as well as companies with sound financial credentials which are mainly operating in countries with low levels of political risk.

NOCs in countries in the early developmental stage and with little or no production struggle to self-finance through earnings retained from upstream operator payments (including data sales and signature bonuses) and downstream levies and commissions – the former account for approximately two-thirds of their revenues and the latter one-third.[13] In a low-price environment, those upstream payments will decrease as exploration activities slow. NOCs in countries with no production will need to scale back their spending.

[12] Securities and Exchange Commission, *Petrobras Annual Report – Form 20-F*, 15 May 2015, pp. 26–27.
[13] Kenya's NOC has extensive retail and downstream operations which account for the bulk of its revenues. The research on which these conclusions are based was carried out by Valérie Marcel for Chatham House's New Petroleum Producers Discussion Group. See also Marcel, V., 'Unlocking the Potential of Africa's NOCs', *KPMG Global Energy Institute*, 11 April 2014.

Box 1: Finance channels for NOCs

In the cases of Saudi Aramco, Abu Dhabi National Oil Company (ADNOC), the Kuwait Petroleum Company (KPC), Sonangol, SOCAR, Kazmunigaz and Pemex – all of which are 100 per cent government-owned – the government approves the budget, leaves the necessary cash flow with the company and takes the rest through taxes, royalties and dividends. Commercial and operational independence varies from company to company.

NOC borrowing from the financial markets (if necessary) takes place at the government level or sometimes through tanker or marketing subsidiaries (PDVSA-CITCO), domestic upstream integrated or international upstream subsidiaries (CNPC-Petrochina-CNOOC; Kazmunigas-KMGEP), or incorporated joint ventures (Sonangol-CNOOC; China Sonangol).

Risks may be reduced for lenders if the NOC pays oil export revenues into an escrow account held abroad (PDVSA-CITCO).

Foreign joint-venture partners, where these are allowed, can be required to fund the NOC share of exploration and initial development, the cost of which is reimbursed out of eventual production (as in Angola and Azerbaijan). Where the terms do not provide for early finance by foreign partners, projects may be held up by a failure to find the NOC's share of finance (as in Nigeria). In addition, foreign partners may suffer in cases where the NOC is the operator in the joint venture and fails to control the project, manage cash flows and communicate with lenders.

Most governments of emerging African producers with no cash flow at present (such as Mozambique or Kenya) can raise funds from the sale of exploration and development rights to foreign companies – provided the geology and economics are attractive. Beyond that, funding depends on government budget allocations. Since most of those countries are currently net oil importers, low prices have no direct impact on the government's ability to support the establishment of the industry.

Equity

Even before the 2014 oil price collapse, equity investors were concerned that, with few exceptions, many companies in the oil sector were heavily committed to high-cost projects for which they had a poor record of execution. Among other concerns were declining rates of return (both on capital and on equity), large write-downs that all too often followed acquisitions, and the lack of a growth narrative or even a story focused on value.[14] Notwithstanding high oil prices, returns were poor,[15] which raised the question of how companies would manage if prices fell. There were, of course, exceptions – for example, BG could offer the prospect of growth as long as the news flow from the Santos Basin was improving, as could Tullow during the period in which its exploration had a successful run. However, the sector as a whole failed to perform well for equity investors.

Companies linked to the US shale developments were other exceptions to the rule. In the case of those companies, a strong growth narrative attracted bond and equity financing. Since the price collapse, the rig count has fallen, particularly in less productive areas, and completions have been delayed; as a result, production has slowed and a backlog of wells drilled but not completed has built up. Those wells have a potential short-term capacity of 300,000–500,000 bbl/d production and may be brought

[14] Mitchell, J. with V. Marcel and B. Mitchell, *What Next for the Oil and Gas Industry?*, Chatham House, October 2012.
[15] Miller, S., 'Perspective: The Clashing of Big Oil Versus Big Finance', *Energy Intelligence Finance*, 8 April 2015.

on stream relatively quickly.[16] Productivity continues to increase as technology and production practices improve, reducing the cost of production. Even at the current lower oil prices, the bulk of US shale is economic. Although a handful of companies have signalled distress (Sabine-Forrest, Samson), some finance remains available: small and mid-cap exploration and production (E&P) companies in the US raised US$8.42 billion in the first quarter of 2015,[17] and some have issued convertible notes as well.[18]

As the sector matures, there is likely to be some consolidation – that is, poorly funded good assets will be taken over by companies that are better financed. The dependence on high-yield bond financing is likely to reduce as companies mature: some companies will shift to more equity funding. But the existence of a large, specialist high-yield investor community in the US underpins the provision of funding to US shale. Owing to access to finance, straightforward ownership and infrastructure, as well as a position around or below US$60 on the cost curve (and falling), US shale production will remain significant.

Credit ratings

Credit rating agencies have reviewed their ratings of oil and gas companies in view of the lower oil prices since mid-2014 and the reduced expectations for long-term prices. In Europe, ratings were confirmed in January 2015 but the outlook has since changed to negative for many companies. In the US, Standard & Poor's downgraded eight companies in December 2014 and revised the outlook for 12 companies to negative. Lower ratings mean increased costs of debt; for oil and gas companies, this factor partly offsets the effect of the general supply of liquidity on interest rates. Agencies are closely watching managements' ability to reduce operating and project costs, and whether they are prioritizing stability of dividends and scaling back or deferring projects.

Bank lending

Many banks were restructured after the financial crisis of 2008–09. Some have wound down their expertise in the oil and gas sector and, as a result, are reluctant to fund projects that are complex and/or carry technical and political risk. Banks' balance sheets are now more robust as regulators require them to hold more capital against their loan books, to tighten lending requirements, to limit proprietary trading and to be more transparent. But this means that they have less capital to lend and are withdrawing from sectors that they regard as risky and from project finance where risks are ring-fenced to the lender. The number of banks prepared to lead project finance has declined as lending has shifted to the corporate level. Export credit agencies and international financial institutions are stepping in to fill the breach for larger projects that have broad development significance.

There are various mismatches between the banks' new requirements and those of the companies. Lower hydrocarbon prices increase the risks of lending to companies in early-stage development – especially those that do not have strong internal cash flows. These companies need to retain banks' confidence by demonstrating robust controls, tight cash management and good communication with lenders (which look for practical solutions and want to avoid becoming involuntary owners of any assets to which they have recourse). Many small and new NOCs do not understand what is required of them in terms of accounting, disclosure and corporate governance to meet the

[16] Doan, L. and D. Murtaugh, 'US Shale Fracklog Triples as Drillers Keep Oil From Market', *Bloomberg Business*, 23 April 2015.
[17] Crooks, E., 'Low returns drag down US shale oil industry', *Financial Times*, 24 March 2015.
[18] Crooks, E., 'US oil groups forced to focus on profitability', *Financial Times*, 25 March 2015.

expectations of financial markets. As those requirements become more complex, NOCs, especially in emerging countries, will depend increasingly on help from various technical advisory groups, such as the Commonwealth Secretariat, the Norwegian Oil for Development Programme, the Canadian International Resources and Development Institute, the Asian Development Bank and the World Bank. Such institutions, in turn, will need to keep pace with the growing financial sophistication required.

Bonds

As bank lending has become more difficult to obtain, oil and gas companies have made increasing use of bond funding, encouraged by the low interest rates that have resulted from the liquidity injected into the financial markets through QE in the US, Japan and the eurozone. While low-risk borrowers offer low or even negative interest rates, investors looking for higher yields have accepted the risks associated with the oil and gas sector, as illustrated by the success of the recent Rosneft bond issue. CNOOC financed its 2013 acquisition of Canada's Nexen through a combination of bank lending and notes. In the first quarter of 2015, US E&P companies raised US$7.9 billion from bonds and US$11.7 billion from syndicated loans. The Iraqi government has approved US$12 billion of treasury bonds to pay foreign oil companies.

The large bond markets in the US and UK are both liquid and deep; they supply institutional and retail investors, while agencies provide credit ratings for public bonds. The Nordic bond market, in which issues are smaller and structures more flexible, brings international retail investment to small and mid-cap companies in the US and UK.

Yields in the oil and gas sector are sensitive to oil and gas prices. To some extent, government owners of companies can protect bondholders in their companies against risks by guaranteeing their companies' bonds. Frequently, however, investors will have looked beyond the state company to the credit of the government. In rare cases, by using escrow accounts and asset pledges, a state company can secure a higher credit rating than its government owner. Sometimes one of the NOC's subsidiaries can even secure a better rating than either of these: for example, CITGO (the US marketing subsidiary of the Venezuelan NOC PDVSA) retained a B3 rating when Moody's downgraded both the NOC and the government to Caa3 in early 2015.[19]

A broader risk for bond investors is unrelated to oil and gas. When the liquidity supply slows, yields will rise in other sectors and in economies that are not dependent on hydrocarbons. Oil and gas companies will need to increase yields to continue to attract capital, especially if they are planning high-cost and technically risky projects or are focused on countries with high 'above ground' risks of political interference, poor management, corruption, heavy taxation and onerous obligations as regards local procurement and content. Unless they can offer higher yields, companies – whether private or state-owned – will find it difficult to secure refinancing or new financing in the face of competition from high-yield businesses in other sectors and countries where such risks are less serious.

Reserve-based lending

Reserve-based Lending (RBL) provides companies with a facility, drawn down as necessary, to fund development capital expenditure. RBL financing is an important source for oil E&P companies, as it

[19] Moody's, 'Moody's Downgrades Ratings of PDVSA and CITGO Petroleum', *Moody's Investors Service*, 15 January 2015.

is flexible, straightforward to arrange and ideal for development capex. It is shorter-term than other funding options and subject to revision twice yearly (March/April and September/October). It does, however, carry refinancing risk and companies must provide security. This structure has worked well for companies, but banks now need to decide how to manage during the current period of extreme oil price volatility. Historically, banks have used a price deck (oil price assumptions) discounted (typically by 30 per cent) against prices that are not as volatile upwards or downwards as the oil price itself. The semi-annual redeterminations are for the future period, based on past prices, although there is scope for discretion. The March/April 2015 redetermination appears to have passed without major casualties, perhaps because the oil price appeared to have recovered from its lows and because previous borrowing capacity had not been fully used: in November 2014 only 25 per cent of US shale companies had used as much as 50 per cent of their RBL facility. Returns are not high enough for RBL to be syndicated out. In general, RBL is not an option for NOCs as they cannot offer recourse to ownership of their reserves.

Advance sales of oil or gas

'Take or pay' contracts for the sale of gas have long been common in the gas industry, for both domestic and export sales. Failure to 'take' the contracted gas leaves the reserve stranded, but the owner of the reserve is remunerated. Royalty trusts are a variation. For many years the Prudhoe Bay Royalty Trust provided the only major example of an advance sale in which part of the price risk was passed to the investment market: BP, the producer, undertook to sell a guaranteed volume of Prudhoe Bay crude oil production to the trust at a fixed price (set to ensure all costs were covered); BP then raised funds through a public offering of the trust on the New York Stock Exchange. Under such an arrangement, investors have an asset whose value is determined entirely by the market price of oil. The royalty trust mechanism has tax advantages in the US. The early Forties Field financing in the North Sea worked in a somewhat similar way for the repayment of bank loans to develop the field.

Advance sales are a relatively simple fundraising avenue: they do not involve any surrender of reserves as security. In 2014, a consortium of banks bought US$1.56 billion of Nigerian oil in advance, enabling NNPC to repay various loans – essentially, the company's loan service obligation has been replaced by an obligation to supply oil. In 2009 the Chinese Development Bank lent US$10 billion to Petrobras for supplies of 200,000 bbl/d to Sinopec; it advanced another US$2.5 billion in March 2015, despite the downgrading of Petrobras to junk status by Moody's. Loans to Venezuela for oil supply are reported to total US$56 billion (some of which has been redeemed), plus another US$30 billion recently announced.[20] Details and timing are obscure. Meanwhile, Chinese deals to buy Russian oil contain a clause on advance payment for a portion of what are otherwise standard and very long-term supply contracts. Oil is priced at market, and a discount reflects the advance component.

Traders such as Glencore have invested in both oil production (to secure physical barrels and thus reduce exposure to market volatility) and advance purchases in the past few years. Clearly, this strategy remains attractive; however, the extent of Marubeni's recent impairment charge on earlier investments raises the question of just how willing traders will be to increase their oil and gas assets until some stability emerges or asset prices fall.[21]

[20] Energy Intelligence, 'China-Latin America: Re-Evaluating the Relationship', *Energy Compass*, 27 March 2015.
[21] Inagaki, K., 'Marubeni halves profit forecast on $1bn writedown', *Financial Times*, 26 January 2015.

Asset disposals

The financial squeeze on large companies has reduced the number of potential buyers of assets from small E&P companies: many large companies will be sellers rather than buyers of assets. A buyer in the past, private equity has raised enormous funds for energy investment (US$50 billion by 2013, while Carlyle Group recently raised US$900 million specifically to take advantage of lower asset prices) but has made large write-downs on pre-2014 purchases and is now less likely to buy unless prices are heavily discounted. Traditionally, private equity has preferred assets with cash flow from production that can support borrowing and a future leveraged sale. Thus the space for small-scale, early-stage E&P companies may become almost uninhabitable: quality assets will find their way into companies with strong balance sheets and the rest will be left to go fallow.

The prospect of 'going fallow' also applies to NOCs in countries without production or in early-stage development. Besides government budget allocations, which tend to be unreliable, the nascent African NOCs (such as NOCAL and NAMCOR) depend on foreign upstream operator payments. In a low-price environment, such payments will decrease as exploration activities by foreign companies slow or are abandoned. NOCs (and their governments) in countries without production or in early-stage development will need to consider revising tax and often costly local-content obligations, to compete with opportunities for international companies in other countries – even if the prospects are technically and potentially economic in today's price environment. Total's renegotiation of terms for the ultra-deepwater Kaombo project in Angola is a case in point.

Project financing

Project financing (high gearing, off the corporate balance sheet, with no recourse outside the project) is not typical of risky exploration and production, but has been widely used downstream – for pipelines, chemical plants and liquefied natural gas (LNG) terminals, among other things – especially if long-term off-take or throughput contracts have been signed with a major producer or off-taker that has stable tariff or toll revenues. These types of project have attracted investors such as pension and infrastructure funds, which have similarly long time horizons and are thus well matched. Although many banks have shifted from project to corporate finance (the new limitations and risks notwithstanding – see above), export credit agencies and development finance institutions are working with the World Bank to enable the implementation of larger infrastructure projects. This would involve offering partial risk guarantees (from the International Development Association), long-term financing (from the International Finance Corporation) and political risk insurance (from the Multilateral Investment Guarantee Agency). However, it remains unclear how such an approach could build momentum or to what extent it might be affected by the lower oil prices and uncertainty about longer-term oil and gas demand.

Spin-offs

Besides disposing of assets, private-sector domestic and international companies are reconsidering their internal capital allocation processes and seeking ways to decapitalize parts of their businesses. Both private and state-owned companies will review the scope for the disposal of non-core assets, such as shipping and service companies. NOCs may follow suit. In the case of NOCs, this may conflict with obligations to develop local content.

Asset disposals may involve the use of structured products, such as royalty structures if the tax regime permits (there are royalty investors in the US, the North Sea and Israel) or master limited partnerships (MLPs), which apply only to certain assets and low tax regimes but are quite widely used (e.g. Shell for pipelines and Petronas for ports). Such products match a specific portion of a company's business with a specific set of investors rather than offering simply a conglomerate investment to the financing community. There is potential for more such financial 'de-glomeration' as oil companies have an enormous amount of capital tied up in assets to which little value is being added and that could be packaged to appeal to various classes of investor. Whether more widespread business 'de-glomeration' follows would depend on how long the price instability lasted and near what level the oil price ultimately stabilized.

Readjustment

The combination of lower short-term cash flow, the long-term prospect of subdued oil prices, the expected tightening of monetary policy and the new limits on the lending capacity of banks creates a new paradigm in which oil and gas companies' management of financing is almost as important as their operations.

The three categories of company that will be most adversely affected – and their high-risk, high-cost projects deferred or mothballed – are:

- Small and mid-cap private-sector E&P companies, particularly those that have high-cost assets and little flexibility to change their portfolios;
- NOCs in emerging producer countries whose governments cannot provide additional support or where either the geology or the governance frameworks are not attractive enough to appeal to IOCs; and
- Mid-cap and smaller international companies as well as listed NOCs whose financial structure and capacity are out of step with their business opportunities (such companies will seek to restructure or engage in M&A, spin-offs and new forms of financing).

The two US (Chevron and ExxonMobil), two Chinese (CNPC and CNOOC) and three European IOCs (BP, Royal Dutch Shell and Total), all of which have low gearing, investment-grade ratings and substantial cash reserves, could emerge stronger: they will have the opportunity to strengthen their portfolios by buying high-quality assets during the readjustments awaiting other companies. Four of the 'supermajor' IOCs were buying back shares in 2014. Such practice may ease, though it can make sense to borrow more cheaply than the cost of equity and retire shares.[22]

Three 'super NOCs' – Saudi Aramco, the Kuwait Petroleum Company and the Abu Dhabi National Oil Company – have a similar financial and national operating capacity to that of the 'supermajor' IOCs. They are likely to look to extend their portfolios downstream, especially in Asia.

Another four listed companies – Apache, BHP-Billiton, ConocoPhillips and ENI – are financially resilient and have the potential to strengthen their upstream business and financial position, possibly including through M&A. Some will need to cut capex significantly in order to acquire good new projects or businesses.

[22] 'If someone wants to let me use their money at Treasury +58 basis points or something under 3% for 10 years or something around 3% for 30 years, and I can generate a return on capital employed last year north of 16%, that is probably a smart thing to do.' Statement by Rex Tillerson, chairman and CEO of ExxonMobil Corporation, at Analysts' Meeting and Discussion, 4 March 2015, Presentation and Q&A Session, Q 13.

Overall, companies with sufficient cash or access to funding can take advantage of much lower project costs (including rig and service company costs) as well as potentially better terms, and may be able to extract good projects from badly funded companies. They can seize opportunities to shift the balance of their portfolios lower down the cost curve, thereby making themselves more robust in the face of continuing uncertainty and providing some defence against the risk of new, strong climate change mitigation policies. If oil prices remain subdued for a long period, the sector will not expand; but investors may be rewarded by more focused managements undertaking more realistic projects.

The large mergers that followed the price fall in 1986 are unlikely to be repeated given the size of today's top-tier companies and competition issues, particularly in the downstream sector. A creative rearrangement below that level would be welcomed by the markets. The recently announced acquisition of BG Group by Royal Dutch Shell is a good example (see Box 2, below).

In this environment, companies with strong balance sheets can acquire assets and companies at attractive valuations to a greater extent than before the fall in prices, and can reshape their portfolios for the new era. Rex Tillerson, the chairman and CEO of ExxonMobil, summed up the situation as follows: 'There is really no limitation on what we might be interested in and considering.'[23]

Box 2: Royal Dutch Shell-BG acquisition

In April 2015 Royal Dutch Shell announced a deal to acquire the BG Group, supported by the BG board. Market capitalizations at the time were US$421 billion for Royal Dutch Shell and US$70 billion for BG. When complete, the acquisition will give Royal Dutch Shell a more diversified geographical portfolio and strengthen its already strong position in the global LNG market. There should be cost savings. As BG has no downstream oil investment, Royal Dutch Shell's exposure to OECD overcapacity will be reduced proportionally. Upstream it will secure BG assets in emerging markets, including Egypt and the important Santos Basin, which is one of the few very large-scale, structurally low-cost assets available to private-sector companies. For many years Royal Dutch Shell has had a high weighting in projects in the fourth quartile on the cost curve (LNG and heavy oil) and, in recent years, relatively low reserve replacement ratios. Its overall portfolio will be improved. The management of the combined group will have opportunities unavailable to Royal Dutch Shell on its own – regardless of whether its apparently more optimistic view of the prospects for the oil price is justified. Whether the 50 per cent premium to be paid is good value for Shell shareholders may depend on whether the write-downs of BG's LNG assets have been conservative enough. For BG shareholders, it is a way out of a company that appeared to have lost momentum.

[23] Crooks, 'Exxon CEO says oil prices will stay low'.

Climate Change Policies

There are profound mismatches between the investment opportunities that will be available for oil (and to some extent for gas) if enough governments adopt the so-called 2° policies (referred to in this paper as 'strong' policies),[24] and the opportunities available if such policies are not adopted.

The policy drivers

The Intergovernmental Panel on Climate Change (IPCC), established in 1988, concluded in 2014 that it is 'extremely likely' that recent trends in global warming are caused by an increase, resulting from human activity, in the concentration in the atmosphere of emissions of greenhouse gases (GHGs).[25]

In the Cancún climate agreements of 2010, the governments of UN member states committed to establishing clear objectives for limiting emissions of GHGs. Increases in the global mean temperature of more than 2°C above 'pre-industrial' (1860–70) levels would bring unacceptable risks of severe, widespread and irreversible impacts globally and, in particular, in various locations and ecosystems.[26] (Increases up to now are estimated at 0.65–1.06°C.[27]) Between 2020 and 2040 irreversible concentrations of carbon dioxide (CO_2) are likely to cross the line at which the 2°C increase becomes more likely than not. The expected long-term change in temperature will result from concentrations of GHGs that will remain in the atmosphere for many decades (methane) or hundreds of years (CO_2). There is no 'wait and see' option for introducing stricter policies to control emissions.

For this reason, several initiatives and intergovernmental agreements have sought further limits on GHG emissions. In October 2014 the EU agreed on a climate change pact that should cut its GHGs by 40 per cent from 1990 levels.[28] In November 2014 President Barack Obama and President Xi Jinping issued a joint announcement in which China for the first time volunteered to commit to a peak in its GHG emissions around 2030 (the US and China together accounted for 44 per cent of fuel-related CO_2 emissions in 2013). The next critical step in the process is a Conference of the Parties to the 1992 UN Framework Convention on Climate Change (UNFCCC) in Paris in December 2015, which is likely to focus on a legal framework for voluntary commitments (so-called 'intended nationally determined contributions', or INDCs). Individual countries are to submit those commitments for a review (the nature of which is still to be determined) by 2020. Policies will continue to tighten in order to achieve the objective of limiting the probability of warming exceeding 2°C. (If these 'strong' policies are misguided or unachievable, the result will be higher global warming and its associated risks.)

[24] These policies (referred to in this paper as 'strong') would limit to 50 per cent the probability of global warming exceeding 2°C. They do not necessarily entail complete 'decarbonization' of the world economy.
[25] IPCC, *Fifth Assessment Report (AR5)*, September 2013–November 2014.
[26] IPCC, *Climate Change 2014: Synthesis Report (SYR AF5)* and 'Summary for Policy Makers (SPM), section 1.3', in *Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change,* 2014; and MIT, *2014 Energy and Climate Outlook*, 2014.
[27] Section 1.3, 'Attribution of Climate Changes and Impacts', in IPCC, *Climate Change 2014: Synthesis Report* (SYR AF5), part of *Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, 2014; and MIT, *2014 Energy and Climate Outlook*, 2014.
[28] According to the IEA's *World Energy Outlook 2014,* Chinese emissions of CO_2 would peak between 2030 and 2040 under the so-called New Policies scenario; EU emissions have already peaked and would fall to around 60 per cent during the period 2035–40; and Japanese emissions have peaked too, and would fall 30 per cent below 1990 levels by 2035.

'Strong' policies

Governments are not planning to restrict fossil-fuel supplies. The policies under consideration aim to lower demand – through a combination of tax measures and, above all, tighter regulation, sometimes called the 'proxy carbon tax'.[29] The cost to consumers of carbon taxes, regulations on emissions and switching to low-carbon technologies will drive a wedge between the cost to consumers of using fossil fuels and the price of fuel that the producers receive (thereby increasing the differential). In this paradigm, consumer demand will be restrained by such measures, while supply will be restricted owing to the reduction in demand with lower prices for producers of fossil fuels. Lower demand will therefore lead to less investment in supply than would have been the case without strong climate change policies. The IEA estimates that during the period 2012–35, levels of investment in fossil-fuel supply will fall by 15 per cent for gas, 20 per cent for oil and 33 per cent for coal. But over the same period there will be higher investment in energy efficiency, renewables and biofuels.[30]

Investment in 'efficiency' is difficult to estimate. Technologies developed outside the energy system – for example, in electronic, communication and control technology; materials; building design; vehicle design; and control of production processes – will combine with regulations on emissions to change the way in which energy is consumed. The climate change objectives will be unachievable if such change does not take place.

'Oil in limbo'

Even without strong policies on carbon emissions, the Massachusetts Institute of Technology (in its *2014 Energy and Climate Outlook* – henceforth *MIT 14*) and Rystad Energy (in its report *Petroleum Production Under the Two Degree Scenario* – henceforth *Rystad Budget 2013*) estimate that, respectively, 185 billion bbl or 570 billion bbl of proven oil reserves will not be burned by 2050. An excess of reserves over forecast consumption has persisted throughout the industry's history, but the difference today is the impact of climate change policies on the scale of the excess. As of the end of 2013, the world's proven reserves could support current levels of consumption for 53 years.[31] McGlade and Ekins, using a University College London (UCL) model, estimate that with strong climate policies, 430 billion bbl (or 33 per cent) of currently recognized reserves would remain unburned in 2050, but 340 billion bbl of resources would be developed (i.e. produced and added to reserves).[32] The Rystad study suggests 50 per cent of reserves could be left unburned in 2050. Neither oil and gas investors nor the financial sector as a whole will know for some years whether strong policies will be adopted. The difference between the oil (or gas) that would remain in the ground in any case (that is, without strong policies) and what would remain if strong policies were adopted is, in effect, the volume 'in limbo' – in other words, the reserves whose future is uncertain.

Investment to develop this 'oil in limbo' will be wasted if strong climate change policies are adopted; but will be necessary to maintain supplies if such policies do not emerge or are not supported by investment in renewables and energy efficiency. This is what has been termed the 'Janus risk': looking ahead to the future means that under the 'strong' 2°C policies, a significant part of the

[29] ExxonMobil's 2014 report, *Energy and Carbon – Managing the Risks,* estimates likely proxy carbon taxes of US$80/tonne of CO_2 (US$3.6/bbl) in the OECD by 2040.
[30] IEA, *World Energy Investment Outlook Special Report,* 2014.
[31] BP, *BP Statistical Review of World Energy 2014*, June 2014.
[32] McGlade, C. and P. Ekins, 'The geographical distribution of fossil fuels unused when limiting global warming to 2°C', *Nature*, Vol. 517 (January 2015), pp. 187–90.

proven and probable reserves of oil and gas would be left in the ground, and expenditure to find and develop them would be wasted. On the other hand, investment in this oil and gas will be needed if weak climate change policies look to the past and perpetuate the historical patterns of oil and gas dependence. Failure to invest early in either 'oil in limbo' (which may be needed if low-carbon policies fail) or low-carbon alternatives would limit possible future options.

As regards natural gas, up to 10 per cent of proven reserves would be unburned in 2050 if there were no strong measures on carbon emissions. With strong policies the figure would be more or less the same: lower demand in some sectors would be offset by increased demand in others, such as power generation. In the power sector, gas would gain market share but would face reduced demand because of renewables and efficient use. The discovery and development of resources to convert to reserves would be justified in either case.

Uncertainty

Section 1.1 of the IPCC's 2014 *Synthesis Report Summary for Policymakers* summarizes 'unequivocal' evidence of global warming. Section 1.2 argues that it is 'extremely likely' that the dominant cause of observed warming since the mid-20th century has been human activity, which has increased atmospheric concentrations of CO_2, methane, nitrous oxide and various industrial gases. Indeed, there appears to be an almost linear relationship between the cumulative emissions of CO_2 and other GHGs, on the one hand, and the global mean temperature, on the other.[33]

However, the complexity of climate systems and the limitations of existing models mean that considerable uncertainty remains about the rate at which future global warming will occur as a result of emissions; and about how such warming will translate into global and regional manifestations of climate change, such as frequent and/or severe extreme weather events, changes in precipitation, desertification and the rising level of the sea. At the same time, there is uncertainty about the impacts of those developments on human and natural systems. But that does not provide a rationale for delaying emission reduction efforts – unchecked, global warming poses a significant risk of disastrous outcomes. Rather, it makes the case for acting now to reduce emissions and mitigate that risk.

What matters most for the climate is the combined accumulation of all GHG emissions. CO_2 from the burning of fossil fuels accounts for about two-thirds of total GHGs, but its share is rising.[34] Methane leaks from the energy system account for most of the remainder. Non-energy emissions are largely CO_2, industrial gases, and methane and nitrous oxide emissions from agriculture, forestry and other land use (AFOLU). Methane and nitrous oxide are difficult to measure and generally are not directly affected by policies to restrict the burning of fossil fuels (though restrictions on methane consumption will reduce leaks). However, what happens to the non-burning sources of emission (and how they are counted) clearly affects the quantity of fossil-fuel combustion that would be consistent with any limit on total GHG emissions.

These key climate uncertainties combine with 'normal' uncertainties about economic growth, technical development, and resource costs and availability.

[33] IPCC, 'Summary for Policy Makers (SPM 1.3)', in *Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change,* 2014.
[34] MIT projects that the share of non-fossil fuel emissions of CO_2 will rise from 35 per cent in 2010 to 43 per cent in 2050, before falling to close to 33 per cent by 2100 (see MIT, *2014 Energy and Climate Outlook*, p. 2).

Analysis

It is important for the discussion about 'unburnable' oil, gas and coal to take into account that the policies under consideration by the UN and the major GHG-emitting countries are designed to reduce the *consumption* of fossil fuels. In other words, there are currently no explicit caps on fossil-fuel *supply* – only the constraints resulting from policies to reduce consumption or from suppliers' own emissions-reducing activities. The latter will affect the competitiveness of fuels for which production involves high CO_2 or methane emissions (such as production from tar sands).

In integrated energy-climate models such as those of MIT and UCL, these 'compliance' or 'proxy' costs appear as shadow prices for CO_2. As noted above, they drive a wedge between the cost that the consumer incurs to use energy (or to avoid its use) and the price the primary fuel producer receives. Thus there is a pricing paradox whereby low demand is generated by the cost to consumers but producers receive low prices. Those prices may be even lower – and investment in high-cost projects at risk – if producers overinvest relative to the reduced demand.

In almost all the studies reviewed in this paper, the markets for oil, gas and coal are seen as being determined by the competition between those fuels and the competition between them and non-fossil fuels.[35] Demand for fossil fuels is influenced by the substitution of non-fossil or 'carbon neutral' technology (nuclear, renewables and hydro) in the electricity-generation sector. To the extent that electricity generation requires less fossil fuel, there may be some room to use more fossil fuel for other purposes (subject to restrictions on emissions from final energy consumption in other sectors).

In addition, energy efficiency – that is, reducing the energy intensity of the economy – affects emissions from final consumption of energy in most countries and sectors. Energy efficiency replaces some energy inputs with the use of equipment, materials or techniques that use less energy to deliver transport,[36] heat, materials, or mechanical or chemical processes. The share of other industries (vehicle manufacturers, builders and industrial processors) in the value chain increases and that of the suppliers of energy decreases. Strong policies will reinforce the long-term trend[37] towards greater efficiency but will ultimately fail if the industries directly concerned with consumption (e.g. vehicle manufacture) fail to invest in more efficient technology for consumers. If 'strong' policies are forced on sectors that are unprepared for them, assets in those industries will be stranded.

Differences in methodologies and assumptions, not least in setting confidence intervals and including non-CO_2 GHGs, mean that no definitive number exists for the quantity of emissions it would be 'safe' to tolerate; rather, there are various estimates. That said, all those estimates clearly indicate that there is a significant deviation from current emission trajectories – global emissions need to peak within the next decade or so and decline rapidly thereafter. Policies must be made and strategies adopted on the basis of the information available. The challenge is how to put in place a global process that moves investment in a sustainable direction but can be adjusted as uncertainties are reduced by new knowledge, decisions and events.[38]

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[35] The original Carbon Tracker study is the exception since it assumes quotas for production based on estimates of reserves.
[36] The average efficiency of the total US vehicle fleet improved 29 per cent from 2001 to 2014 (see Liebrich, M., 'Big oil is about to lose control of the auto industry', *Bloomberg New Energy Finance*, 16 April 2015).
[37] See IEA, *World Energy Outlook 2014*, Chapter 8.
[38] 'Our *Outlook for Energy* does not envision the "low carbon scenario" advocated by some because the costs and the damaging impact to accessible, reliable and affordable energy resulting from the policy changes such a scenario would produce are beyond those that societies, especially the world's poorest and most vulnerable, would be willing to bear, in our estimation' – from ExxonMobil, *Energy and Carbon – Managing the Risks*, March 2014; also 'The most likely path for carbon emissions, despite current government policies and intentions, does not appear sustainable' – statement by CEO Bob Dudley, introducing BP's *Energy Outlook 2035*, February 2015.

Recent analyses

The IPCC reports of 2013–14 constitute an encyclopaedia of scientific and economic studies which bring together and summarize the results of hundreds of models that integrate climate change and the use of carbon fuels, with numerous qualifications and ranges of probabilities. This paper has derived 'IPCC budgets' from those sources[39] for the upper and lower ranges of cumulative CO_2 emissions from fossil-fuel combustion (not including methane emissions, industrial gases and land use-related emissions) between 2011 and 2050 that would keep the increase in the global mean temperature below 2°C. This is shown by the horizontal red and yellow lines in Figure 1 below.

Figure 1 also shows estimates of cumulative emissions from fossil-fuel combustion to 2050 under various recently published modelling estimates. In this paper we have adjusted results for compatibility of dates and made CO_2 /fuel conversions where these are not reported.

The key assumptions and methods of the estimates used in the figures can be summarized as follows (full references are given in the Appendix).

Assumptions

- The *MIT 14 Outlook* and the *WEO 14 Current Policies* estimates are similar and assume, to a greater or lesser extent, the continuation of climate change policies agreed at Copenhagen but with no additions to them.
- *WEO 14 New Policies* assumes the implementation of additional policies either adopted or under consideration by governments since Copenhagen but insufficient to meet the 2° benchmark for 'strong policies'.
- *WEO '450', UCL 2014, Carbon Tracker 2013* and *Rystad Budget 2013* estimates are designed to comply with a 450 ppm (parts per million) constraint on all GHGs: 'strong policies'. The UCL model provides for competition between and within fossil fuels as well as cost-based competition between reserves and resources (see below).
- A further case, *MIT Expected* (not shown in Figure 1), estimates emissions and production under a cautious set of assumptions about what may be agreed in the Paris 2015 climate negotiations.[40]

Methodology

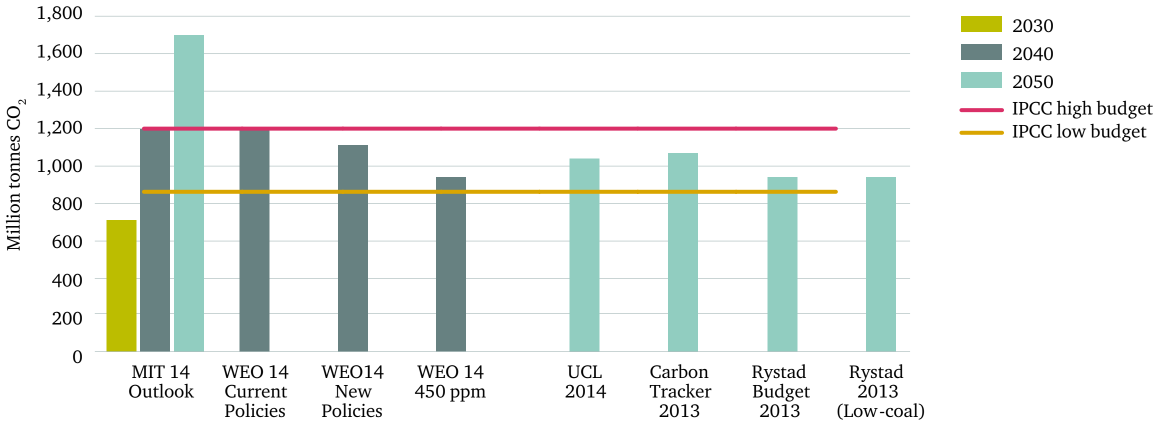
- The *MIT 14 Outlook* is derived from the MIT Integrated Global System Model (IGSM) developed by the Joint Program on the Science and Policy of Global Change.
- *UCL estimates* are from the UCL Institute for Sustainable Resources model TIAM-UCL. Both the MIT and UCL models are climate-energy-fuel integrated models that provide for competition between the fossil fuels in disaggregated markets and from disaggregated areas of supply and include or take into account feedbacks to the economy and climate.
- The WEO estimates are from the IEA *World Energy Outlook 2014*, and derived from an IEA World Energy Model (WEM), in which emissions are estimated on the basis of various economic and energy price scenarios.

[39] IPCC, 'Summary for Policy Makers (SPM 1.3)', in *Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, 2014*.
[40] Jacoby, H. and H. Chen, 'Expectations for a New Climate Agreement', *MIT Joint Program on the Science and Policy of Global Change*, August 2014.

- The *Rystad estimates* are based on fuel shares from the *WEO 450* estimates with a variant with lower coal use (*Rystad 2013* 'low coal' shows how switching from coal to gas can increase the total fossil-fuel demand within the same CO_2 emission constraints). The Rystad estimates allocate demand to producing areas according to their costs.
- *Carbon Tracker 2013* allocates the carbon budgets between fuels, according to their share of oil and gas reserves and coal resources. *Carbon Tracker 2014* (a follow-up study, not shown in the figure) estimates the impact on the break-even prices for new oil and gas supply projects.

Broadly speaking, these models differ in how the constraints on carbon emissions are specified and how consumption of the various fuels changes in response to those constraints. The point is critical for determining the impact on oil as opposed to coal, for example. Carbon capture and storage plays only a small part in all of the scenarios. WEO and MIT results are published to 2040 or 2050 (UCL, Carbon Tracker, Rystad and MIT 14), although model calculations extend to 2100 for the purpose of recognizing emission constraints as well as taking into account the need for some fossil reserves to remain in place in 2050 to support (much reduced) consumption after that date.

Figure 1: Estimates of cumulative CO_2 emissions



Sources: See Appendix.

The main conclusion from Figure 1 is that additional climate change policies cannot safely be deferred. Without such policies, accumulated emissions are likely to clear the lower hurdle for risking 2°C warming sometime between 2030 and 2040 and the higher hurdle shortly thereafter. It is unlikely that the recent fall in the oil price would significantly change that dynamic even if it were to result in a permanently lower oil price. The important judgment is political: when additional policies are adopted and how strong they are. (Some companies have taken the view that strong additional policies are unlikely at the present time.)

The above estimates were made before the collapse of oil prices from around US$100/bbl for WTI in mid-2014 to around US$60/bbl in June 2015. The low-emission estimates (with 'strong policies') generate significantly lower prices than under 'current policies'. In the WEO '450' case the oil price remains roughly flat at around US$100/bbl instead of rising to US$150/bbl (2013 US$). The UCL and Rystad models produce similar results. Carbon Tracker's 2014 cost-curve study (CT 2014) identifies tranches of potential production for which the economics would be at risk if the oil price fell below US$95/bbl, and below US$75/bbl.

This shows how the difference between the cost charged to consumers and the price obtained by producers (the 'wedge' described above) results in lower demand and lower prices. The lower producer prices (not budget mechanisms) limit production to meet demand constrained by climate change mitigation policies. The collapse in oil prices in 2014–15 is in some ways an illustration of the mechanism that might be at work if the '2° policies' were applied today, but only to oil. Policies to restrict consumption of other fuels will be necessary, too, in order to bring CO_2 emissions below the risk threshold whereby the level of global warming is not likely to exceed 2°C.

Fossil fuels under strong climate change policies

The integrated climate-energy models (subject to all the other constraints on supply and demand, including 'proxy' carbon costs) balance supply and demand for energy use in each main sector as well as in each main group of countries and allow for international trade in fuels. The market allocation between fossil fuels is likely to reflect both the value of energy released when the fuel is burned and the 'proxy' cost of CO_2 emissions. The ratio of energy to carbon varies from one fuel type to another (the range of ratios of CO_2 to energy for various crude oils, refined products and grades of coal in all their various uses is large). Key ratios are set out in Table 2 below, based on broad indications (from IPCC guidelines) in round numbers (to the extent that the specifics of the sector allow).

Table 2: Ratio of potential energy (gigajoules) to 1 tonne of carbon in primary fuel

Fuel type	Energy: Gigajoules per tonne of carbon emitted
Gas	18
Oil	14
Coal	11

Source: Draft IPCC Guidelines, https://www.ipcc.ch/meetings/session25/doc4a4b/vol2.pdf.

There will be a long-term shift in demand towards fuels with a higher energy potential (and therefore economic value) per tonne of carbon emitted. The extent and speed of that shift will depend on fuel prices and the 'proxy' carbon cost as well as on the demand technology bias (e.g. liquid fuels for vehicles). For any given level of economic activity and demand for related energy, fossil-fuel consumption will be lower.

Table 3 below gives a rough indication of the impact of that shift on total fossil-fuel demand in the estimates presented above.

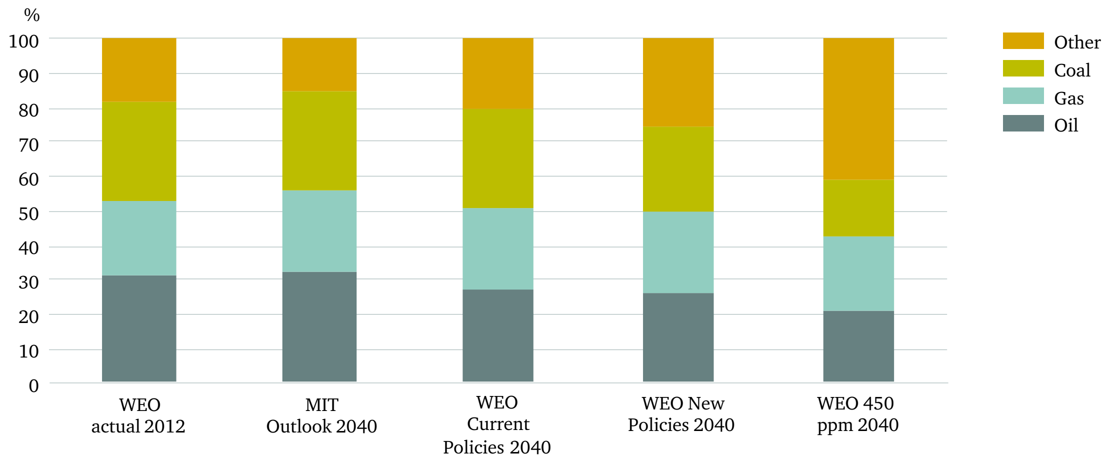
Table 3: Estimates of accumulated fossil-fuel production from 2012 onwards (billion tonnes oil equivalent)

	to 2040	to 2050
MIT 14 Outlook	275	390
WEO Current Policies	390	
WEO 14 New Policies	360	
WEO 450	310	
Rystad Budget		310
Rystad Low-coal		320
UCL		470

Sources: See Appendix.

Different estimates show different shares of the various fuels in the primary energy market compared with 2012, as reported with the same definitions by the IEA (see Figure 2 below). Policy assumptions in the *MIT 14 Outlook* and the *WEO 14 Current Policies* are similar but the former provides for a larger share for nuclear power. For the period 2012–40 both these estimates show declines in the energy consumption shares of oil and coal, and increases in those of gas and non-fossil fuel. All the WEO estimates show a larger absolute increase in non-fossil fuel consumption; *WEO 450,* which represents 'strong policies', shows the fossil-fuel share of primary energy demand declining from 80 per cent to 60 per cent by 2040, while total energy demand would be lower because of increased efficiency in consumption.

Figure 2: Estimates of shares of primary energy consumption in 2012 and 2040

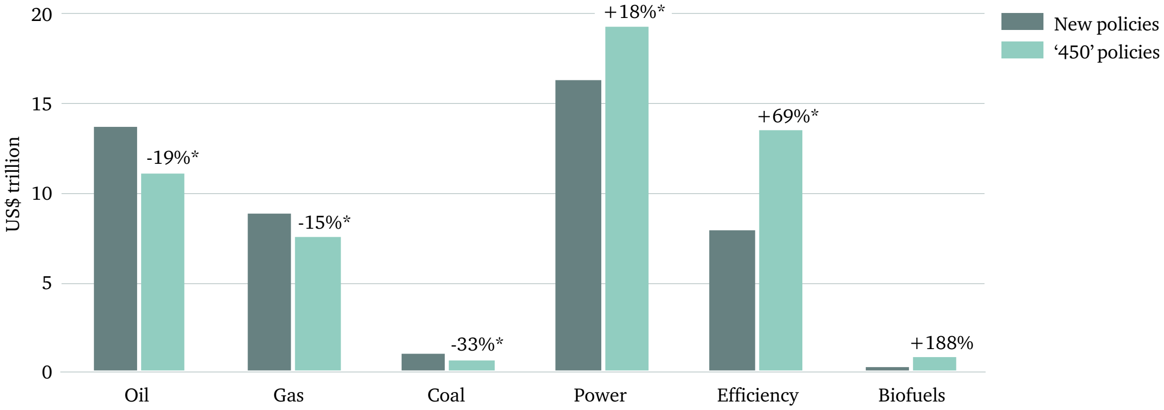


Comparable data not available for other models.
Sources: See Appendix.

Investment

The IEA's 2014 *World Energy Investment Outlook* (WEIO) shows the differences in the levels of investment required under the WEO estimates of the results of 'new policies' (described above), i.e. policies that it considers likely to be adopted at the 2015 UN climate change talks; and of its '450 ppm' policies, which assume the objective of no more than a 50 per cent probability of a 2°C increase in global warming – described as 'strong policies' in this paper. The quantum of investment in energy supply is not very different, but its composition changes, as Figure 3 below shows.

Figure 3: Global energy accumulated capex in the energy industry from 2012 to 2035



* Percentage difference between new policies and '450' policies.
Source: IEA, *World Energy Investment Outlook*, 2014.

As Figure 3 shows, in the '450' estimate an additional US$8 trillion would be spent on energy efficiency.[41] Furthermore, there would be a large swing away from fossil fuels to renewables (classified under 'power'), biofuels and demand technology (i.e. 'energy efficiency'), but little change in overall energy investment.

Therefore the financial challenges arise at the sector level: in the '450' estimate, oil investment would be one-fifth and coal investment one-third below what they would be under the 'new policies' likely to be adopted in December 2015; while investment in power, biofuels and energy efficiency would increase in both absolute and relative terms, requiring shifts in investment flows through the financial markets.

Also required will be clarity of policy and a measure of government support for new instruments to finance new technologies and infrastructure, especially in low-income countries.[42] Few enterprises span more than one sector – the exceptions being some international oil companies, which straddle oil and gas, both of which would require less finance in the '450' scenario of 'strong' climate change policies.

Reserves

The alternative to producing from reserves within the '450' climate change policies is to produce them without any restrictions in order to meet expected demand over a comparable period. Our analysis below shows that without such restrictions on demand, accumulated oil production equivalent to 70–90 per cent of the current commonly estimated 1,700 billion bbl of oil reserves would be used by 2050.

In reality, reserves are dynamic. Some future production will be met by exploration and development, which will convert current 'resources' to 'reserves', while higher-cost reserves in current estimates would be left in the ground. The UCL model estimate[43] shows that 430 billion bbl (33 per cent of UCL's lower estimate of 1,300 billion bbl of oil reserves) would not be developed, while 340 billion bbl of the remaining resource base, not classified at present as reserves, would be developed. The comparable Rystad estimate suggests that production under the '450' policies would be 280 billion bbl lower than without such restrictions.

[41] This is higher than the US$4.1 trillion increase to 2030 estimated by the Global Commission on the Economy and Climate in *The New Climate Economy*, 2014.
[42] Global Commission on the Economy and Climate, *The New Climate Economy*, 2014.
[43] McGlade and Ekins, 'The geographical distribution of fossil fuels unused when limiting global warming to 2°C'.

Resources

In addition to the reserves, there are an estimated 3,000–4,000 billion bbl of resources, many of which consist of unconventional oil and natural gas liquids. Normally some of those resources will be added to reserves (as in the UCL estimates) because they are cheaper to develop than reserves already in the portfolio, which may remain unburned in the long term; some will stay in the ground forever. What matters both for the climate and for the oil producers is the effect of policies on oil demand, not the ratio of uncertain production to an even more uncertain denominator.

There is, however, no escaping the uncertainty over future technology and economic conditions, which play a major role in determining the level of reserves and resources. The volume of oil reserves will remain uncertain and that of resources even more so, regardless of which definitions of reserves and resources are used.

Fossil-fuel resources have no economic or environmental future without the prospect of investment to prove reserves and create production capacity. Because of decreasing reservoir pressure, oil production capacity declines as reservoirs are depleted. The IEA's *WEO 2014* projections estimate that without investment in enhanced recovery, and in the absence of any new developments and/or discoveries, production of crude oil will fall by three-quarters by 2040 – from about 87 million bbl/d to about 22 million bbl/d. That would be only half the amount needed to meet demand in the 450 ppm estimate[44] ('strong policy') and would require continuing investment in oil exploration (to find lower-cost sources) and development.

Different agencies use different definitions and reporting systems.[45] For the purpose of this paper, we have used 1,700 billion bbl as a reference point for reserves and 6,000 billion bbl as a reference point for resources. The UCL estimate uses lower numbers on the grounds that countries with very high ratios of reserves to production – such as Canada and Venezuela, both of which have large reserves of heavy oil and oil sands – have no prospect of investment to develop a significant part of these usually quoted reserves before 2050.[46] The OPEC Secretariat, in its *World Oil Outlook 2014,* cites higher figures on the basis of members' statements.

Figure 4 below shows various estimates of cumulative oil production – excluding production from resources that may be converted to reserves (see above). These figures are compared with current estimates of reserves to show the percentage of unburned reserves. The top half of Figure 4 shows production to 2050 and reserves unburned at that date; the bottom half provides the same information for the period to 2040.[47] For each estimate, the comparison is with the commonly used figure of 1,700 billion bbl of proven and probable reserves, except for the UCL and OPEC models, which are based on lower and higher numbers, respectively, for reasons explained immediately above. In all these cases oil and gas will continue to be used after 2050.

For the period up to 2050, the *MIT 14 Outlook* and *Rystad Unrestricted* estimates assume no significant new policies to restrict oil consumption.[48] They are outside the IPCC 'budgets' for CO_2 emissions that would limit to 50 per cent or less the probability of global warming exceeding 2°C (see Figure 1). The comparison between the *MIT 14* and *Rystad Unrestricted* estimates, which involve no new restrictions

[44] See IEA, *World Energy Outlook 2014*, Table 3.6.
[45] These are reviewed in IEA, *World Energy Outlook 2013*, November 2013, and *World Energy Outlook 2014*.
[46] See McGlade, C., 'A review of the uncertainties in estimates of global oil resources', *Elsevier Energy* 47 (2012), pp. 262–70.
[47] There are no published IEA WEO numbers for 2050, and no Rystad or Carbon Tracker numbers for 2040.
[48] MIT, 2014 *Energy and Climate Outlook*, *2014*. Rystad Energy, *Petroleum Production Under the Two Degree Scenario*, 2013.

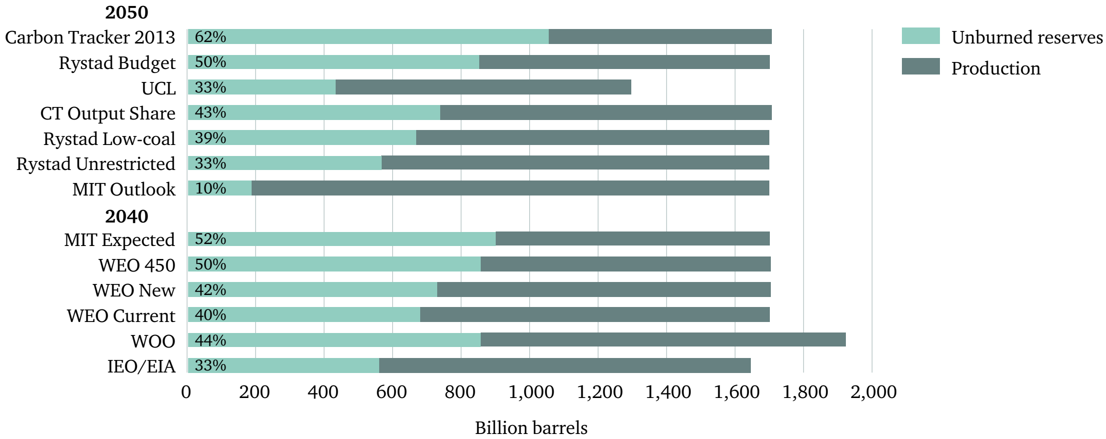
on carbon emissions, and those which involve various degrees of restriction is therefore a measure of the potential effect of stronger policies on the use of reserves, oil production and the associated capital investment to meet restricted consumption.

Figure 4 shows that:

- In the Rystad 2050 estimates, the unburned reserves increase from 33 per cent in the unrestricted estimate to 50 per cent in the 'budget' estimate (which follows the IEA '450' scenario for 2040, assuming that the IPCC maximum CO_2 emissions are extended to 2050). Rystad also offers a 'low coal' estimate in which gas production is maximized at the expense of coal. The resulting reduction in CO_2 emissions allows more oil to be produced in line with the IPCC 'budget' and reduces the unburned oil to 39 per cent of the assumed reserves.
- The UCL estimate, which is based on a lower reserve figure, leaves 430 billion bbl (33 per cent) of present reserves of oil in the ground in 2050, but at the producer prices generated substitutes these with 340 billion bbl from lower-cost resources which are not included in the UCL present reserve figures.
- The 2040 comparison is between the *WEO 14 Current Policies* estimate, which would leave 40 per cent unburned by 2040, and the *WEO 450* estimate, which would leave 50 per cent unburned by 2040.
- In the *Carbon Tracker 2013* model, restricted demand is divided among fossil fuels in accordance with their share of oil and gas reserves and coal resources, leaving the equivalent of just over 60 per cent of oil reserves in the ground in 2050. If demand were divided on the basis of production in the *WEO 450* estimate, the unburned share of currently estimated reserves would be just over 40 per cent (within the range of the Rystad estimates).
- The share of total *resources* unburned in these scenarios is inevitably smaller, as the denominator – the volume of resources – is about four times greater than the volume of currently estimated reserves.

The key point of this comparison is that it is the effect of climate change policies on the consumption of oil, gas and coal, rather than the absolute size of reserves, that is likely to have an impact on company and government planning.

Figure 4: Use of oil reserves



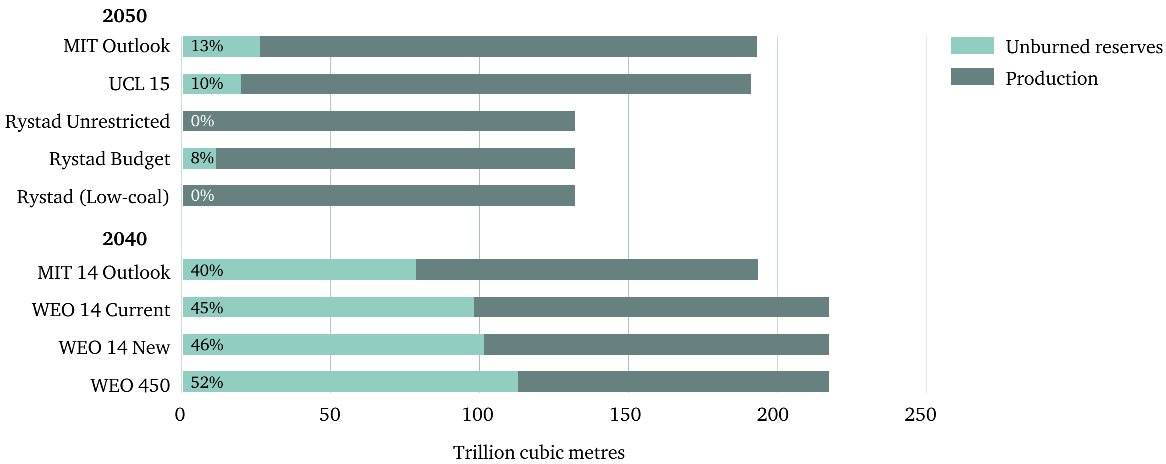
Sources: See Appendix.

Natural gas

Estimates from the main agencies for gas reserves vary quite widely. Figure 5 below is based on the reserve figures of each estimate (except that of MIT, which publishes no reserve figure and for which the UCL figure is used). Typically, the volume of resources is around four times that of reserves. The development of both hydraulic fracturing and horizontal drilling has transformed the potential for resources to be converted to reserves, and the outlook is changing rapidly. Unlike oil, however, gas is expensive to transport long distances; and liquefaction plants are massive projects, which, like long-distance pipelines, may be difficult to finance. The result is that markets are separated by transport costs, and that balances have to be struck within each geographical region. 'Stranded gas', as in Prudhoe Bay, Alaska, is a familiar problem. Between 70 per cent and 80 per cent of gas is consumed in the country in which it is produced. Principal models (MIT, WEO and UCL) reflect these conditions. Figure 5 compares projected accumulated production with current projections of gas reserves in the main available estimates reviewed above for oil.

As in the case of oil, gas reserves are dynamic. Resources will be brought into production if they are cheaper than the most expensive projects in the existing reserve base. The UCL model estimates that approximately half of the forecast accumulated production will be supplied from the existing reserve base, and the rest from the addition of reserves from currently identified resources. By 2050 there would be pressure on gas reserves and a need for resources to be converted to reserves. This is reflected in the estimates to 2050, which show rapid growth in the use of gas. In the estimates, the use of gas is not constrained as a result, since gas resources are available to supplement present reserves. The challenge is not to reduce but to maintain the momentum of exploration and development, particularly of large gas infrastructure projects.

Figure 5: Use of gas reserves



Sources: See Appendix.

Where is the 'limbo oil'?

In 2013 wholly state-owned and/or state-controlled listed companies supplied nearly 60 per cent of consumption from more than 70 per cent of global reserves. If the top 20 privately owned listed companies were to cease production (19 per cent of supply from 5 per cent of reserves), the reserves of the state-owned companies could, over time and with the necessary investment, maintain global production at current levels for nearly 50 years – and even longer if demand were reduced by climate change policies.

Oil reserves are concentrated in a small number of countries and regions. About half the reserves left unburned as a result of 'strong' climate policies would be in Saudi Arabia.[49] The Middle East holds roughly half of the proven and probable reserves, while together Venezuela and Canada hold one-quarter. 'Ultimately recoverable' oil resources are spread over a wider geographical area – this applies, above all, to so-called unconventional oil. As regards estimated proven gas reserves, just over 40 per cent were in the Middle East as of end-2013, but that share falls below 20 per cent for the total resource base.

Table 4 shows a breakdown by region of reserves unburned at the end of 2014 (i.e. the remaining reserves), compared with the UCL estimate for 2050, which is designed to fall within the range of the IPCC 'budget' for emissions intended to hold below 50 per cent the probability that global warming will exceed 2°C ('strong policies'). The UCL estimate is used here because of its geographical disaggregation and because it leaves more expensive reserves in the ground, after allowing for additions to reserves from the resource base as described above. Not surprisingly, the Middle East, which starts with the largest share of remaining oil and gas reserves, still has the largest share of such reserves in 2050. North America, which is dominated by the private sector and has aggressive depletion policies, runs down its remaining reserves by 2050 and faces less risk of having stranded reserves.

Table 4: Percentage share of unburned oil and gas reserves

	Oil		Gas	
	End-2014	**2050**	**End-2014**	**2050**
Middle East	48	61	43	48
South and Central America	19	13	4	5
North America	14	10	6	1
Africa	8	5	8	5
Russia and CIS	7	6	29	33
Other	4	4	10	8

Totals may not add owing to rounding.
Sources: 2014 figures, *BP Statistical Review of World Energy 2015*; 2050 figures, UCL – McGlade and Ekins (see Appendix).

Who owns the oil and gas in limbo?

Most of the oil and gas reserves and resources outside North America are state-owned. In some countries, reserves are exclusively owned and operated by state-owned oil and gas companies; in others, the state or state company contracts with foreign private-sector (mainly listed) companies to carry out development projects and exploration. In a small number of countries, foreign companies can acquire longer-term rights to explore and develop. And in Russia, Norway and Brazil, there are

[49] McGlade and Ekins, 'The geographical distribution of fossil fuels unused when limiting global warming to 2°C'.

listed 'mixed' companies whose majority or controlling shareholders are the resource-owning state governments or companies.

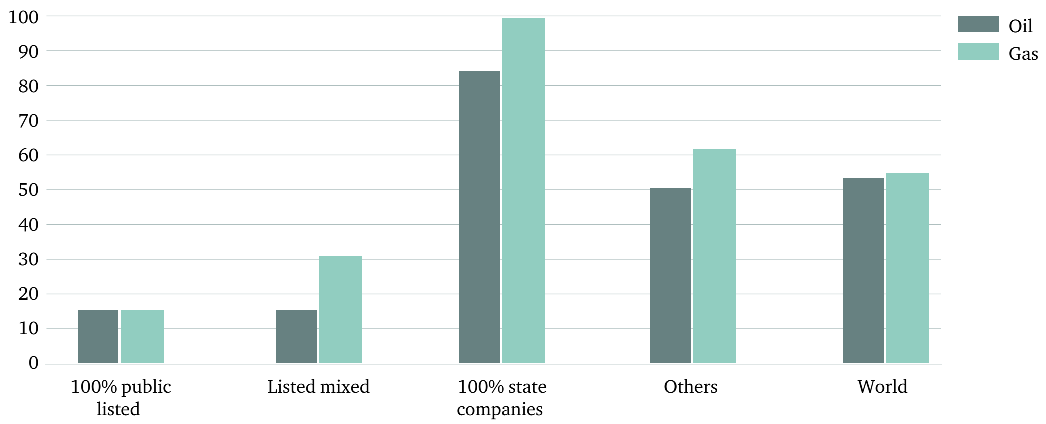
State companies' exclusive rights limit the role of private-sector companies in the development of oil and gas reserves in major producing countries other than the US, Canada and Europe. Many have focused on the development of technology either in the deep seas or in the Arctic Circle.[50] These are high-cost projects at the upper end of the industry cost curve. Some smaller companies look for opportunities in emerging producer countries, where the technical challenges are simpler but beyond the capacity of the local state companies. Business opportunities for such foreign investments will be restricted if climate change policies result in lower demand, and if that lower demand is associated with lower prices (for the reasons given above); in such cases, high-cost projects are left either as unburned reserves or as resources unlikely to be developed within a commercially viable timeframe (as emphasized in the Rystad scenarios).

At the same time, private-sector companies typically have reserves that cover only 10–15 years of their production. Their exploration and development programmes are driven by the search for lower-cost resources and the maintenance of a portfolio of projects that can be developed on normal financial planning horizons. This means such companies have time to adjust. Also, unlike the national companies, they are free to reallocate investments between regions, market sectors and developments or even outside the traditional oil and gas sector (although this is risky, as the diversification experiences of the 1980s showed).

The companies and countries that face the most difficult decisions will be those with the largest volumes of potential oil in limbo – at least some of which may be burned if climate change policy targets are not met, but will be unburnable if they are. Clarity from governments about the structure and timing of climate change policies is hence vital for the adjustment process.

Figure 6, below, compares the number of years for which production at the present rate can be sustained from end-2013 reserves for 50 companies. The list covers 20 listed companies that are 100 per cent privately owned, 11 mixed (public-private) companies and 19 companies that are 100 per cent state-owned.

Figure 6: Years of production at 2013 rate from 2013 reserves



Sources: Private, mixed and state-owned companies: Energy Intelligence Group (EIG), *2014 Petroleum Intelligence Weekly Top 50* (ranking of major oil companies); others and world (not included in the EIG data): *BP Statistical Review of World Energy 2014.*

[50] Carbon Tracker estimates US$1.1 trillion worth of projects in deep waters, the Arctic and oil sands, which require a market price of US$95/bbl to be commercially viable.

Projections for 2050 depend on changes in the expected pattern of ownership of reserves and resources, and the position on the cost curve of each company's assets. Carbon Tracker, in its cost curve study,[51] estimates that 84 per cent of projects identified at wholly or partly state-owned companies would be economic at prices in the US$60–80/bbl range (which would be consistent with the assumed lower demand). Only 40 per cent of projects available to the private sector (under present patterns of ownership) would be invulnerable to 'strong' climate change mitigation policies of the kind described in the scenarios above, and which may be driven forward by the UN negotiations in Paris in December 2015.

Implications for investment in oil and gas

There is a profound mismatch between, on the one hand, the investment opportunities available for oil (and to some extent for gas) if 'strong' policies aimed at limiting to below 50 per cent the probability of global warming exceeding 2°C are adopted and, on the other hand, those available if such policies are not adopted. Governments party to the UNFCCC have agreed to develop a framework starting at the Paris meeting in December 2015. It is unclear how strong and effective these policies will be, and whether they will be supported by the necessary investment in renewables, efficiency and other low-carbon fuels. There are wide ranges of uncertainty about numbers indicating the effect of GHG emissions on the global climate, but evidence has been reinforced by the IPCC reports of 2013 and 2014. Uncertainty about numbers is closely connected to uncertainty about policies.

Summary of climate change analysis

- The general direction of global climate change policies is clear, but their details and the speed with which they will be implemented are uncertain.
- The agenda of policies for the December 2015 Paris UN conference (to which there may be a follow-up in 2020) aims to restrict the consumption of oil, gas and coal in order to limit and reduce the emission of CO_2. Direct control of fossil-fuel supply is not on the agenda. Supply will be reduced because regulation or taxation of consumption will result in large differentials between the cost to consumers of using (or avoiding using) fossil fuels and the price of fuel obtained by producers. This wedge will restrain demand through higher consumption costs. This will limit supply by smaller markets with lower prices for producers.
- 'Strong' climate change policies (intended to limit to below 50 per cent the probability of global warming exceeding 2°C) will have an impact on the energy mix, whereby the demand for carbon fuels will be reduced in general, to the disadvantage of high-carbon fuels such as coal and to the advantage of renewables in the power sector. Under any carbon constraints on consumption, using more zero-carbon sources in the power sector would create more room, statistically speaking, for oil to be consumed in the transport sector without increasing total CO_2 emissions. In practice, however, decarbonization policies will be sector-specific and will not necessarily derive directly from overall budgets for carbon use.
- The IEA estimates that compared with current climate change policies, the 'strong policies' would reduce investment required by 2050 in the gas, oil and coal sectors by about 15 per cent,

[51] Carbon Tracker, *Carbon Cost Supply Curves*, 2014.

20 per cent and 33 per cent, respectively. Without a similar quantum of increased investment in renewables, efficiency and biofuels, the consumption of oil, gas and coal would not fall as intended. The IPCC's 2°C threshold would be passed and some irreversible changes would be triggered. Even stronger mitigation and adaptation policies would be required to meet climate change objectives.

- Stronger climate change policies mean less depletion of fossil-fuel resources in the long term (see Figure 4). According to two estimates – *MIT 14* and *Rystad Unrestricted* – described in Figure 4, even without 'strong' 2°C policies, the equivalent of 10 per cent and 33 per cent, respectively, of the prevailing estimates of 1,700 billion bbl of proven and probable oil reserves would not be burned by 2050; with 'strong' 2°C policies, the latter percentage could increase to 50 per cent. The difference of around 290 billion bbl (17 per cent of the generally accepted estimate of 1,700 billion bbl of oil reserves) would be the effect of 'strong' policies on consumption. This oil would remain unburned – in other words, 'in limbo' – by 2050 if the 2°C policies were adopted and worked. However, it would be needed to meet demand if such policies were not adopted or did not work.
- A similar risk of stranded assets applies across the energy system, including in investments in infrastructure, fossil-fuel power plants and grids, as well as in high-emission vehicles, the factories that make them, and processes and equipment made obsolete by the development of more energy-efficient alternatives.
- In reality, reserves are dynamic, as already noted. In the UCL estimates described above, the currently identified reserves left in the ground would be more or less substituted with the conversion of lower-cost resources to reserves that would be produced to meet demand under the 'strong' 2°C policies.
- Restrictions on demand affect different owners and producers differently. In 2013 wholly owned state companies controlled two-thirds of global reserves (today's unburned oil) and supplied just over 40 per cent of consumption. Roughly half of global unburned oil or oil in limbo in 2050 would be under the control of state companies in the Middle East, mainly in Saudi Arabia.
- Given their potential, in general, to develop lower-cost reserves and resources, the state-owned companies as a group could, over time and with the necessary investment, replace the private-sector listed companies' supplies and maintain global production at current levels for nearly 50 years. They could do so for even longer if demand were reduced by climate change policies. According to one estimate, 84 per cent of the projects in the state sector identified as necessary to meet oil demand under 'strong' climate policies would be commercially viable at producer prices of up to US$80/bbl, while only 40 per cent of projects currently available to the private sector would be in a similar position.

Conclusions

This paper suggests that in the short and medium term, financial strategies will have a critical part to play in dealing with the mismatches that result from these developments. In the longer term, the climate negotiations of December 2015 will boost momentum for policies that will depress global demand for fossil fuels. That momentum will draw on the political commitments embodied in the US–China agreement on climate change cooperation and on parallel commitments by the EU.[52] The policies under discussion, which aim at controlling and reducing emissions by fossil-fuel users, drive a wedge – a large differential – between the costs incurred by consumers to use energy (or to avoid using it) and the prices that fuel producers charge. Although the age of cheap oil production may not yet be over, the age of cheap oil use is coming to an end.

The commodity cycle for oil is not under control

The 2014–15 mismatch between static Chinese demand and growing US supply is a stress test for the OPEC system, which the organization has failed by not sharing cutbacks in production. Brent oil prices fell from US$116/bbl in June 2014 to US$45/bbl in January 2015 and recovered by mid-June to US$64–65/bbl – still around 50 per cent above the 1986–2006 average price in real terms. The Saudi decision to defend its market share and accept the consequences for oil prices leaves the oil market without a regulator to buffer future mismatches between supply and demand. The next phase in the current cycle may eventually see higher demand and lower supply – to the benefit of producers that have maintained or increased their market share, including Saudi Arabia and a few cash-rich IOCs that may take advantage of low prices to improve their portfolio of projects.

Capital for oil and gas investment

Most companies (including some NOCs) have cut capex; and many need external funding as the fall in oil prices has reduced the industry's ability to self-finance new investment. Despite unprecedented global liquidity resulting from QE and similar monetary policies that had suppressed yields and pushed investors towards riskier assets, parts of the oil and gas industry were having trouble attracting finance for investment even before the oil price fell. This applied particularly to early-stage exploration and appraisal, which is traditionally funded by equity. Some parts of the sector benefited from the search for yield, especially the US shale sector, which is funded largely by high-yield bonds. And high oil prices led to the funding of high-cost development and production elsewhere, for example in the Arctic and ultra-deepwater areas (although investors became disillusioned by poor results from such projects), as well as in LNG infrastructure.

When the flood of money dries up, financial markets will increasingly find reasonable and even high yields once again in relatively secure economies and other industries. Funds will be scarce for risky investments in oil and for those companies and countries that are dependent on such investments; lower oil prices, which will reduce returns and raise risks, will exacerbate that situation. Mismatches

[52] White House Press Office, 'US–China Joint Announcement on Climate Change', 11 November 2014.

will continue to occur as banks' lending capacity is constrained by capitalization requirements, and as US- and EU-based lenders and equity investors face new regulations on disclosure and related-party procurement.

Uncertainty about oil prices has increased as a result of heightened commodity risks and long-term pressure on demand from climate change policies. That development improves the competitive position of those low-cost producers and suppliers, notably in North America, that enjoy 'above ground' advantages of infrastructure, competitive service providers, the economic incentives of private ownership, and relatively stable political and regulatory regimes. There will be changes of ownership so that good-quality assets are matched with available finance: such changes will be through investment by financially strong companies such as ExxonMobil, internal portfolio pruning, fire sales, the break-up of companies, and approaches like those of L1 Energy and other private equity funds. There will be a shift from macro to micro mismatches.

The impact of the end of QE and similar programmes will vary from one state oil company to another. Some, such as Saudi Aramco, are in a position similar to that of ExxonMobil: if their cash-rich governments would allow them to do so, they could asset-pick around the industry during the readjustment. In the case of others, such as Iran's NIOC, the government needs all their money – and more – at home. Smaller and emerging NOCs, and small early-stage private-sector companies, depend on external finance in one way or another. They will have to improve their 'above ground' risk profile in an environment in which reasonable and even high yields are available elsewhere (but not necessarily in the oil and gas industry).

Oil and gas 'in limbo'?

While the 2015 Paris negotiations may not yield targets that themselves are able to prevent dangerous rises in global temperatures, the resulting framework is likely to allow for the ratcheting up of commitments. The trend will inevitably be towards stronger national policies, including through the common US–China approach. This will strengthen the confidence of investors in renewables and in energy efficiencies across economies.

Meanwhile, high-cost and/or high-risk investment in fossil-fuel supply is subject to uncertainty about when stronger climate change policies will emerge, how strong they will be and how they will affect demand for the various fossil fuels. Both oil reserves and investment would be stranded if strong policies emerged relatively soon, although those reserves would be needed if climate change policies continued to be weak. As long as the uncertainty over policy prevails, such oil is in limbo and investment in it remains risky. As stronger policies emerge and become clearer, private-sector companies, which have only 10–20 years of reserves, will have time to monetize these reserves, reduce capex and increase pay-outs (dividends, special dividends and share buy-backs). Those pay-outs are the channels through which oil and gas companies' profits are recycled away from fossil-fuel production: the financial markets and individual investors reallocate such funds to other parts of the economy, including alternative energy sources and companies committed to higher efficiency. At the same time, some companies can build on existing strengths and assets by adding consumer value: for example, by maximizing their share of the value of hydrocarbon molecules by adding value in chemicals, and by having a bias towards high-value oil (such as lubricants) in transportation fuels.[53]

[53] ExxonMobil, 'Capturing the highest value for every molecule', presentation to stockbrokers' analysts in New York on 6 March 2015.

Diversification that builds on other assets, such as distribution networks for compressed natural gas, fuel cells and hydrogen, presents other options. However, the experience of the 1980s shows that further diversifying into what are, in effect, other industries is risky both for a company's management and for its shareholders.

Governments of state companies, which have oil reserves of 50–100 years, have more existential problems. The question they have to answer is whether their economies can diversify – that is, in this context, whether they can withstand reducing dependence on oil and gas exports to pay for imports for development; and how much other economic sectors will suffer from the slashing of fiscal subsidies currently financed by oil and gas revenues. The potential to achieve this diversification differs significantly from country to country; but investors will need to recognize the risk that oil (or gas) may not be the whole story.

Almost all substantial climate change policies are aimed at reducing the *demand* for fossil fuels – they do not target *supply* directly. Demand reduction is achieved through regulation – so-called proxy carbon taxes representing costs imposed on consumption by regulations limiting CO_2 emissions and, in some cases, direct carbon taxes. Such measures result in the wedge between the cost to consumers and the price available to producers, so that (as the models discussed above show) there can be low demand for carbon-based fuels and low producer prices at the same time. It is because of this differential that the policies work. Together, the two factors reduce fuel demand by diverting part of the consumers' expenditure on services such as transport, heating and industrial products from the fuel supplier to the suppliers of efficient vehicles, equipment, buildings, industrial goods and so forth; and they reduce supply because markets decline and prices to producers are lower as a result.

Oil and gas reserves will not be the only assets in limbo

Although there has been much discussion about carbon-based fuel assets, achieving the reductions needed to limit climate change requires re-engineering every aspect of every economy. The importance of investment in efficiency throughout all economies is clear from the *World Energy Investment Outlook* of the IEA. Investors and lenders should consider the risks to suppliers of the technologies of energy consumption – namely, that their assets will be stranded if they fail to invest in providing efficient technologies to consumers. In the case of the oil and gas sector, the wisest strategies will focus on low-cost production and an appropriate return of excess funds to the capital markets. As regards users of energy, the focus must be on greater efficiency, possibly through new – and disruptive – technologies. And with respect to the role of governments, the clearer both the structure of climate change policies and the timeframe for their implementation become, the greater the likelihood that the risk of investment mismatches can be reduced for all economic participants.

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Acronyms and Abbreviations

ADNOC	Abu Dhabi National Oil Company
AFOLU	agriculture, forestry and other land use
bbl	barrel
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
EIA	US Energy Information Administration
EIG	Energy Intelligence Group
EITI	Extractive Industries Transparency Initiative
GHG	greenhouse gas
IEA	International Energy Agency
INDC	intended nationally determined contribution
IOC	international oil company
IPCC	The Intergovernmental Panel on Climate Change
KMGEP	KazMunaiGas Exploration Production
KPC	Kuwait Petroleum Company
LNG	liquefied natural gas
MIGA	Multilateral Investment Guarantee Agency
MIT	Massachusetts Institute of Technology
MLP	master limited partnership
NAMCOR	National Petroleum Corporation of Namibia
NIOC	National Iranian Oil Company
NNPC	Nigerian National Petroleum Corporation
NOC	national oil company
NOCAL	National Oil Company of Liberia
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
PDVSA	Petróleos de Venezuela S.A.
QE	quantitative easing
RBL	reserve-based lending
SOCAR	State Oil Company of Azerbaijan Republic
UCL	University College London
UNFCCC	UN Framework Convention on Climate Change
WEIO	World Energy Investment Outlook
WEM	World Energy Model
WOO	World Oil Outlook
WTI	West Texas Intermediate

Glossary

Extractive Industries Transparency Initiative: a multi-stakeholder initiative which maintains the voluntary EITI Standard implemented by participating countries to ensure full disclosure of taxes and other payments made to governments by extractive-sector companies.

Janus risk: uncertainty over the development of climate policy, resulting either in wasted expenditure on oil and gas exploration that is impeded by strong climate policy outcomes, or in underinvestment and subsequent lack of growth in a situation of weak climate policy outcomes.

Limbo oil and gas: oil and gas reserves that would be left unburned if strong climate change policies were to be adopted.

Proxy-carbon taxes: government regulation on the emission of CO_2 from the consumption of fossil fuels which inflicts costs on the consumer, additional to any tax already imposed by the consumption of fuel.

Publish-What-You-Pay: a global coalition of civil society organizations which support greater transparency and accountability in the extractive sector by calling for mandatory disclosure of companies' payments and government revenues from this sector.

Supermajors: the world's five or six largest publicly owned oil and gas companies, also referred to as 'Big Oil': BP plc, Chevron Corporation, ExxonMobil Corporation, Royal Dutch Shell plc and Total SA. ConocoPhillips Company is sometimes included in the group. The term does not include national producers and OPEC companies.

Ultimately recoverable oil resources: an estimate of the total amount of oil resources that have been extracted and will be technically and economically feasible to extract over all time.

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