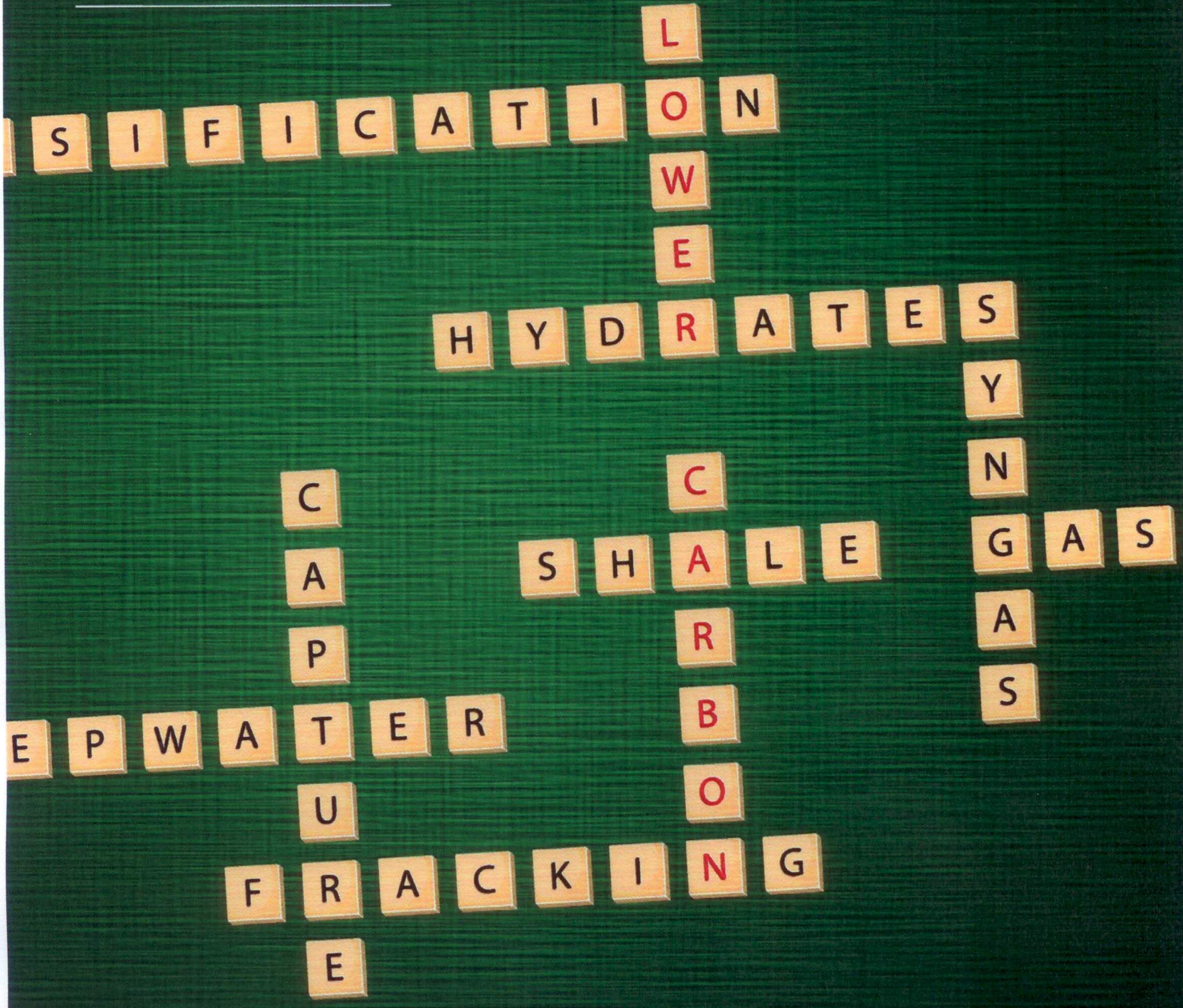
tce
the chemical engineer | issue 869 | november 2013

MINORITY REPORT
Female engineers share their inspiration and insights

HOW ALARMING
Cutting down on control room alerts can boost plant safety

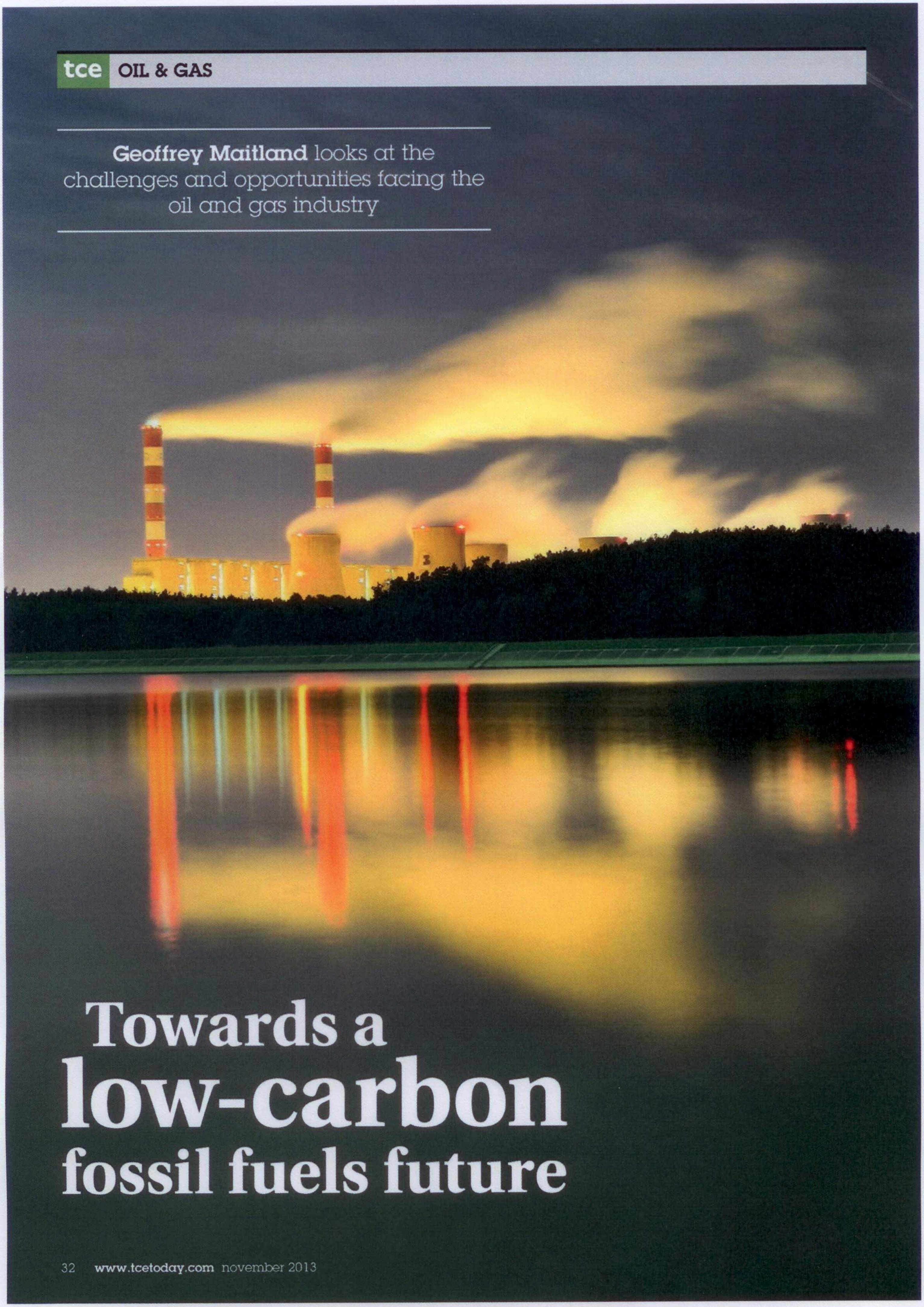
I'D LIKE TO THANK...
IChemE gears up to reward the best our discipline has to offer



Game changers

Planning a cleaner future for fossil fuels

Geoffrey Maitland looks at the challenges and opportunities facing the oil and gas industry



Towards a low-carbon fossil fuels future

FOR some time it has been recognised that urgent action is needed if we are to halt the ever-accelerating rise in atmospheric carbon levels. Successive IPCC reports have plotted the course of our inaction and identified countless scenarios of what should be done to halt and reverse the trend. Yet whilst back in the days of the Kyoto Protocol the ambition was to cap CO_2 levels below 400 ppm and to return to pre-1990 levels of less than 350 ppm by 2020, we have now for the first time (in May 2013) exceeded 400 ppm.

According to the latest IPCC *5th Assessment Report* and the 2013 IEA *World Energy Outlook Special Report*, the aspiration even to keep levels below 450 ppm (which models suggest corresponds to a 50% chance of restricting mean global temperature rises of 2°C) is rapidly receding. These latest carbon-reduction scenarios suggest that even with a response far more rapid than anything the global community has achieved to date, the best we may probably now do is keep levels below 500 ppm, or even 550 ppm, equivalent to 5–6°C mean temperature rises. While we haven't yet reached the point of no return in achieving the 450 ppm target, the latest reports indicate that we seem to be getting very close.

450 – the magic number

The solution is, of course, complex. To meet the 450 ppm scenario we need to reduce CO_2 emissions in 2050 by about 50 Gt/y compared with what we would be pushing into the atmosphere if we did nothing. We currently emit 28 Gt/y and projections are that by 2050 global energy demand will double. All the projections suggest that whilst the amount of renewable generation (and probably nuclear) will increase in a major way over the next four decades the rate of technology development, supply at scale, and cost reduction will not occur quickly enough to address this low carbon energy challenge alone. Besides, developing countries with plentiful supplies of fossil fuels will wish to deploy these in the short term as a cheaper and more secure route to meeting their growing energy needs than the emerging alternatives. So we shall have a mixed energy economy for many decades with fossil fuels still contributing at least 50% to the portfolio in 2050 and probably beyond.

The aspiration even to keep levels below 450 ppm (which models suggest corresponds to a 50% chance of restricting mean global temperature rises of 2°C) is rapidly receding.

Meeting the 450 or even 500 ppm CO_2 capping targets is a tough ask. Yet I believe we can still achieve this if we can take rapid enough action in three areas. First we simply need to use less energy – energy efficiency measures are crucial to solving the climate dilemma and include some of the simple solutions that we all, as individuals, communities and organisations can implement relatively easily and at fairly low cost. This could account for up to 50% of the 50 Gt/y of CO_2 emission savings we are looking for by 2050. Second, the investment in and deployment of very low carbon footprint energies (ie renewable and nuclear) must continue to take place at a level and rate that ensure that they can be moved through to efficiency improvement and large-scale commercialisation as quickly as possible. Projections suggest that about 30% of the 2050 carbon reduction target could be achieved by this route. Third, the inevitable continued use of fossil fuels until the second half of this century means that we must accompany this by preventing as much CO_2 as possible from being released into the atmosphere. The short- to medium-term solution to this is readily available via carbon capture and storage (CCS). Here, CO_2 generated in central facilities, such as power plants and large industrial complexes (eg cement manufacture and iron and steel production being the largest emitters) is captured using solvents or solid adsorbents and then transported and injected as a supercritical fluid into large underground storage sites, such as deep saline aquifers, depleted oil and gas reservoirs or uneconomic coal seams. Whilst there is much development still to be done on CCS to bring the cost down, particularly of the capture stage, and to decrease the energy requirements (the so-called 'energy penalty'), the current generation of CCS processes is perfectly capable of achieving all the technical goals, safely and securely. What is required is the political will to enforce its adoption and create the right fiscal environment (with carbon taxes or trading systems) to ensure their widespread adoption.

the CCS challenge

How then can the oil and gas industry respond to this enormous challenge of continuing to supply the hydrocarbons needed to meet global demand (which will require steadily increasing volumes in absolute terms, even as the proportion of oil and gas overall gradually declines), whilst at the same time contributing to ensuring that as much of the CO_2 released from the use of those hydrocarbons is not released to the atmosphere? Some of the major oil and gas companies have been exploring opportunities in renewables, especially biofuels. But the most straightforward way they can contribute is to make available their technology and depleted reservoirs to develop, with the power sector, governments and all stakeholders, the commercial-scale CCS industry that is required to meet the 10 Gt/y 2050 CO_2 storage target. To achieve this will require about 3,500 large-scale (>1 Mt/y CO_2) CCS projects worldwide by 2050 (compared with over 30,000 fossil-fuelled power plants worldwide at present). With only a handful of large-scale demonstration projects currently in existence, this represents an enormous challenge; but it is also an enormous opportunity with the prospect of a new industry, building on the best of upstream and downstream oil and gas technology, which by the middle of this century could be of comparable size, with all the economic and social benefits that may bring.

pump up the (unconventional) gas

Apart from CCS, the next most straightforward way we can continue using hydrocarbons whilst making major inroads on CO_2 emissions is to use as much gas as possible. Methane produces 50% of the CO_2 generated by the combustion of oil and coal so their widespread substitution by gas, especially for power generation and heating, can at a stroke make a major contribution to meeting lower carbon targets. Natural gas is increasingly talked of a destination fuel, rather than a transition to a largely renewables world, and its use coupled to CCS has the potential to compete with renewable and nuclear as a low emissions energy source. It has the capability of meeting most of the future expectations for fossil fuels. Capacity will not be a problem; proven conventional gas reserves of $>200 \times 10^{12}$ m^3 are enough to meet demand for 65 years at current levels. New reserves will undoubtedly be found and there will be increased use of enhanced gas recovery techniques (EGR) where injection of CO_2 can be particularly effective in ensuring that most of the *in situ* methane is recovered, whilst subsequently being stored in the depleted reservoir. This would provide double the benefits in the reduction of carbon emissions.

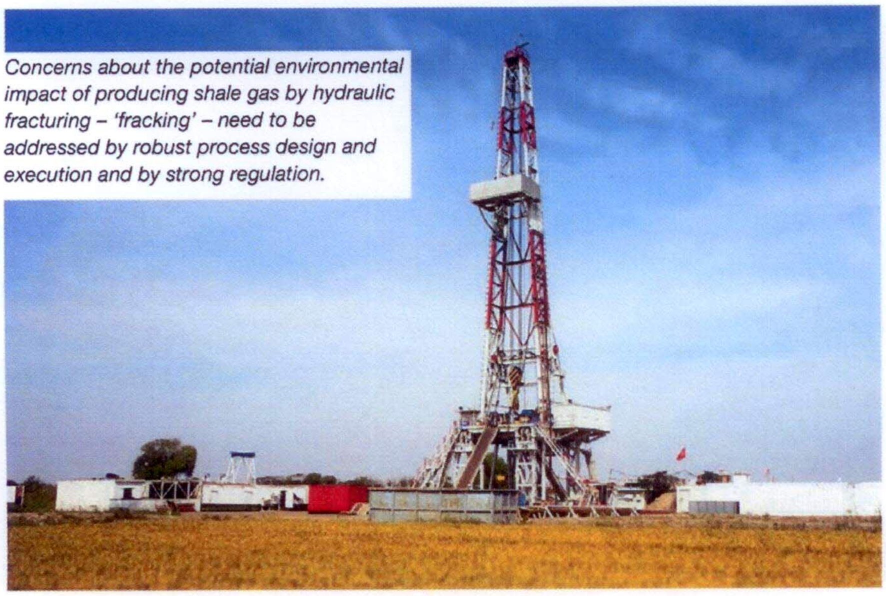
It is becoming increasingly evident that our future gas supplies will not be constrained by conventional reserves. The shale gas revolution in the US, which in a few years has transformed the country from a net gas importer to a potential exporter and at the same time helped reduce its CO_2 emissions by 11% (about 200 Mt/y, down to mid-1990s levels) by substituting gas for coal in power generation, is the most visible example of where unconventional gas supplies have enormous potential to meet energy needs

Even with a response far more rapid than anything the global community has achieved to date, the best we may probably now do is to keep levels below 500 ppm, or even 550 ppm, equivalent to 5–6°C mean temperature rises.

through a gas-based economy. This has been made possible by the combination of drilling long horizontal wells through shale formations and using hydraulic fracturing to create a complex network of fractures that increase the exposed surface area and facilitate the release of the gas trapped in the highly impermeable shale rock. There are large resources of shale gas potentially available in many areas of the world. Shale is the source rock for hydrocarbons that have since migrated to surrounding sandstone and carbonate reservoirs, from which oil and gas is traditionally produced. The residues of gas (and sometimes oil) remaining in the neighbouring shales will thus be available wherever oil and gas has been found, and often in enormous quantities. Current estimates of worldwide shale gas resources, which are likely to be conservative, are about 450×10^{12} m^3 which is about 150 times current global gas consumption levels. In the UK, shale gas resources in the Bowland Shale in Lancashire have been recently estimated at 36×10^{12} m^3 by the British Geological Survey. Together with further significant resources in the Weald region of South East England and elsewhere, this represents many decades of potential supply, even if only 10% of these resources turn out to be recoverable. The UK government is giving strong encouragement for these resources to be recovered, driven largely it seems by security of supply issues; currently the UK is a major gas importer as North Sea gas has dwindled, being highly dependent on LNG from Qatar and pipeline supplies from Norway. It is to be hoped, however, that if shale gas really does take off in the UK that the opportunity will be taken to replace coal-fired power stations with gas, preferably fitted with carbon capture, to make the same impact on our carbon emissions as it has in the US. Similar substitution of coal by gas will be required across the world over the next few decades to avoid simply driving emissions across borders by exporting cheap coal.

accepting fracking

There are of course major public concerns about producing shale gas, largely centred around the controversial hydraulic fracturing, or 'fracking', process. These cover safety and environment issues such as the chemicals in the fracturing fluids reaching aquifers which provide domestic water supplies; the process causing earth tremors and endangering existing buildings; and the large amounts of water used in the process. The large footprint of the equipment, particularly the many heavy horsepower trucks required on location (to create the wells and pump the pressurised fluids) also appears to cause concern. The reality is that all of these risks are small and by good process design and proper regulation can be avoided. Shale gas production should be no more risky than conventional onshore oil and gas production. However, the public perception is real and needs to be addressed by improved communication and engagement from companies, technical experts and government to allay the concerns and also address the 'not-in-my-backyard' issues that are understandable given some of the rural locations potentially involved. The excellent practice exhibited by BP in developing the Wytch Farm oilfield (*pictured, right*) in Dorset, UK, should be used as an example of how the industry already has much experience on how to exploit oil and gas with minimal footprint in sensitive areas.



Concerns about the potential environmental impact of producing shale gas by hydraulic fracturing – 'fracking' – need to be addressed by robust process design and execution and by strong regulation.

coalbed methane and gas hydrates

Shale gas is not the only non-conventional source of gas however. Methane adsorbed in the microporous and fractured structure of coal, 'coalbed methane', has estimated global resources of 250×10^{12} m^3. Very low permeability sandstone gas reservoirs, that require the same fracturing technology as shale gas to release the methane, harbour another 200×10^{12} m^3 of methane. Yet all this pales into insignificance compared with the estimated methane resources contained within gas hydrates, ice-like structures containing methane and other light hydrocarbons in hydrogen-bonded water cages, which are found in shallow subsea sediments and beneath the permafrost. Estimates of how much gas is there vary, but are typically around $20{,}000 \times 10^{12}$ m^3. Recovering gas from gas hydrates is much more difficult than for shale gas and coalbed methane because the hydrate provides the 'glue' that binds together the weak, unconsolidated sand and silt sediments in which they are found. The gas release process destabilises the hydrate structure via increasing the temperature, decreasing the temperature, or by adding solvents (like 'anti-freeze'). This can cause mechanical instabilities in the formations which lead to subsidence and in extreme cases subsea landslides or even tsunamis, with accompanied massive uncontrolled release of methane gas. As such, the process needs to be very carefully controlled.

Since methane gas has an even greater global warming effect than CO_2, the potential consequences of gas hydrate production problems for climate change could be catastrophic. Indeed it is thought that one factor contributing to the ending of the last ice age was the accelerating temperature rise caused by melting of methane hydrates, and a major current climate change concern is that rising sea temperatures or melting of the permafrost could lead to significant release of methane from shallow gas hydrates, which would rapidly make things worse. Nevertheless, there are growing activities on developing safe, controlled hydrate production methods, especially in Japan which has major reserves and no other significant hydrocarbons (hence its reliance on nuclear energy and the major problems that the Fukushima accident has subsequently

Wytch Farm: BP drilled 15 km horizontal wells out under Poole Bay from a low-lying, spill-contained wellhead and production facilities – all hidden in a woodland conservation area which is difficult to find.

had on its energy supply). Viable production of only a fraction of the global reserves could make a major contribution to future supplies of the cleanest fossil fuel.

from H_2O to CO_2

Another potential advantage of non-conventional gas production is that recovery in all the processes can be enhanced by injection of CO_2, as gas, liquid or supercritical fluid. For example, CO_2 could be used as a fracturing fluid for shale gas, replacing water and addressing the concern of the need for large water supplies, especially in arid regions. It also adsorbs on the surface of many of the clays from which the shales are formed, so preferentially displacing the adsorbed methane and remaining sequestered in the high capacity shale formation. We thus have the potential for a combined enhanced production-carbon storage process which optimises recovery of cleaner gas and keeps the CO_2 underground with long-term secure capture. Similar mechanisms are at play with coalbed methane, where the injection of CO_2 to increase methane production and subsequent storage of it within the vast pore-fracture structure of unmineable coal seams is already practised in several regions of the world, including North America, Australia and China, as 'enhanced coalbed methane'. CO_2 gas hydrates are thermodynamically more stable than methane hydrates, so again there is the potential to use fracturing in gas hydrate production to facilitate the injection CO_2. This exchanges with the methane and releases it for enhanced gas production, the CO_2 becoming trapped itself as a stable gas hydrate for long-term storage Unconventional gas therefore has huge potential for both meeting our future energy needs in a much cleaner way and providing CO_2 storage sites whilst improving the CCS economics through enhancing gas recovery.

Energy efficiency measures... could account for up to 50% of the 50 Gt/y CO_2 emission savings we are looking for by 2050.

from gases to liquids

As well as providing power and heating, gas can also lead to liquid fuels, petrochemicals and the building blocks for polymers and other smart materials that we are surrounded by in all aspects of modern life. Gas-to-liquids (GTL) processes are being developed on an increasing scale across the world (including Qatar, Indonesia and South America) to produce synthetic diesel, methanol, dimethyl ether and other high value, cleaner burning liquid fuels, so monetising gas at a time of low gas prices. The GTL process involves steam reformation of methane to syngas ($CO + H_2$) followed by Fischer-Tropsch catalytic conversion to synthetic diesel and high value waxes, or similar processes leading to methanol or dimethyl ether (DME) as alternative liquid fuels. A challenge for the future is to develop catalysts capable of improving the efficiency of the almost 100-year-old Fischer-Tropsch process, preferably by single step direct conversion of syngas to hydrocarbons or methanol. As an alternative to GTL, syngas may be converted using steam via the water gas shift process to CO_2 and H_2, from which the hydrogen can be used for clean electricity generation in gas turbines or fuel cells and the CO_2 transported for various enhanced recovery and storage operations described earlier – so-called pre-combustion CCS.

and oil?

So, from many angles, gas has a great and expanding future as the driver towards the cleaner recovery and use of fossil fuels...but

Conventional gas proven reserves are enough to meet demand for 65 years at current levels.

what of oil? Well we will continue to need increasing supplies and whilst significant conventional reserves remain, the focus will be increasingly on optimising the recovery from existing reservoirs, from today's typical values of 30–40% towards 60–70% if possible. This will be achieved by two main approaches. The first is by so-called real-time reservoir management, a methodology that has been developed over the past ten years and which will become more sophisticated over the decades ahead. This approach involves the deployment of measurements in wells and reservoirs, including time-lapsed seismic, to track the location of oil, water and gas and characterise the properties of the reservoir they are moving through. These are combined with accurate reservoir simulators used to monitor and optimise the water injection and reservoir sweep operations in real time to try to achieve as near as possible uniform, piston-like displacement of the hydrocarbons in heterogeneous reservoirs. Permeability heterogeneity can cause the sweep water to take the high permeability, low resistance pathways and so by-pass oil in low permeability zones unless these more sophisticated flow control strategies are adopted. By producing real-time fluid movement maps – 'the illuminated reservoir' – and linking these evolving images to flow modelling simulators to optimise hydrocarbon displacement by the injected water, increasing amounts of oil and gas will be recovered by avoiding the water by-passing the oil. This allows us to get the process right first time, rather than requiring repeated injection and complex remedial chemical treatments.

The second approach is a renaissance of enhanced oil recovery (EOR) methods, developed in the 1970s and 80s but rarely used then because of their high cost. These aim to mobilise oil that cannot be readily displaced by water-flooding, either because it is trapped in fine rock pores by capillary (surface tension) forces or is too viscous. They involve the injection of a range of fluids – supercritical CO_2, nitrogen, polymer and surfactant solutions, low salinity brines, solvents, steam – designed to address these problems by changing the physical properties of the oil, the displacing fluid, or both. The additional recovery cost is significant and requires oil prices to be higher than about US$60/bbl to become economic, which explains their demise during the last few decades of the 20th century. However, with oil prices now at over US$100/bbl and, according to sources such as the World Bank and the US EIA, likely to remain between US$95–100 long-term, they are now viable and there is much scope for development of further improved processes. The big change now is that, rather than being the last-chance saloon, the solution of last resort when all other cheaper water-flooding options have been exhausted, as they were in the past, they can now be integrated into a real-time reservoir management approach and introduced into the recovery process earlier if this results in optimised recoveries at an economic return. The major oil and gas companies are already working with service companies to take advantage of these improved EOR opportunities.


Alberta oil sands: there are huge reserves of 'heavy oil' but future production processes need to less energy intensive with a lower environmental footprint.

extreme oil

There are two other emerging developments in oil production that are worthy of comment. The first is that the quest for more conventional reserves is taking the oil and gas companies into increasingly remote and challenging environments (such as ultra-deep water and the Arctic) where it is much more difficult and expensive to operate. Maintaining safe and environmentally-benign operations in such locations will continue to be a major challenge, as the 2010 Gulf of Mexico oil spill so graphically highlighted. One consequence of this will be the continuous development of improved fail-safe, low-risk deep drilling equipment, monitors and processes. Subsea separations and processing operations, on the seabed rather than on the surface, will become more commonplace and present challenges of their own. We are starting to see developments in automated drilling and production systems, which can be operated by experts from a remote central control centre. In a similar vein, the use of robots to carry out sophisticated intervention operations in wells and reservoirs, to improve recovery conditions or address potential safety or production emergencies, will become viable propositions in the near future.

A second major development has been the increasing interest in developing non-conventional oil in the quest to meet energy demands, especially for liquid fuels, or to address security of supply issues. These are heavy, highly viscous oils or more solid-like hydrocarbons (like tar sands, bitumens or oil shales) which are difficult or impossible to displace by conventional water-flooding techniques. There are about 7,000bn bbl of such hydrocarbons available, more than double the total amount of conventional oil reserves, recovered and still in place. Whereas 40% of ultimately recoverable conventional oil has resided in the Middle East, about 85% of identified heavy oil resources are in the Americas. The security of supply issues underlying this position goes a long way to explaining why extensive projects have been undertaken in Canada, central US, Venezuela and elsewhere to recover these hydrocarbons, despite the fact that their recovery costs are considerably higher than conventional oil and much more energy and carbon intensive.

The current approach to recovering these reserves is to try to convert the very viscous/solid hydrocarbons to flowable liquids so that they can be displaced from the reservoir and eventually produced at surface like conventional oil. This involves thermal steam injection methods to increase the temperature of the *in situ* hydrocarbons or injection of solvents like supercritical CO_2, liquid propane and LPG. These energy-intensive processes generally lead to significantly lower recoveries compared with conventional oil and to higher processing costs in separating the produced oil from co-produced formation solids and upgrading the hydrocarbons to higher value fuels and products. There has been some exploration of an alternative approach, *in situ* sub-surface processing. This involves heating the hydrocarbons in the formation to convert the heavy hydrocarbons to higher value products by gasification, pyrolysis, partial oxidation or hydrothermal processing with supercritical steam (to methane, syngas, lighter hydrocarbons etc), leaving the heavier, low value materials like asphaltenes underground. The energy can be supplied by injection of steam and air, by electrical heating or preferably by using some of the *in situ* hydrocarbon as a sacrificial fuel in an *in situ* controlled combustion process. One can envisage carrying out more sophisticated catalytic refining or GTL processes in the sub-surface well network ('the underground refinery') and also to capture the CO_2 and other GHGs *in situ* by adsorption or membrane processes so that they are never released from the reservoir – true decarbonisation of oil prior to production.

In this way we could produce to surface only what we need: zero or low-carbon fuels (H_2, CH_4, methanol) and the feedstocks for making fuels, chemicals and polymers (syngas), together with significant heat recovery for external or process use. Most of the carbon would remain underground as captured and stored CO_2 or solid high carbon residues. There are many challenges to developing such an approach, not only in achieving technical viability of intensified sub-surface processing in confined, but long, tubular reactor-separators (ie the well network, currently used only for fluid transport) but also making the costs comparable to the current conventional surface operations. However, as with gas, closer integration of hydrocarbon production methods with CO_2 capture and storage processes may be one route to ensuring that enough of their carbon content is never released to the atmosphere.

So we will continue to produce and use fossil fuels in significant quantities well into this century. However, we cannot afford to do so in the manner that we did in the last century for much longer. At the very least, we need to use more gas, less coal, and wherever possible to capture CO_2 at the point of use and take the carbon out of the system. As illustrated by the examples here, for all fossil fuels closer coupling of production and decarbonisation processes could make further significant contributions to avoiding the catastrophic consequences of climate change and preserving our environment and quality of life to the benefit of future generations. **tce**

Geoff Maitland (g.maitland@imperial.ac.uk) is professor of energy engineering at Imperial College London, and deputy president of IChemE

Chemical Engineering Matters

The topics discussed in this article refer to the following lines on the vistas of IChemE's technical strategy document *Chemical Engineering Matters*:

Energy *Lines 2, 3, 7, 10, 15, 17, 23*

Water *Line 9*

Health and wellbeing *Lines 2, 6, 7, 11, 19*

Visit www.icheme.org/vistas1 to discover where this article and your own activities fit into the myriad of grand challenges facing chemical engineers