Energy Solutions for All
Promoting Cooperation, Innovation and Investment

20TH WORLD PETROLEUM CONGRESS
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Official Host

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Official Venue
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You have the chance to power your own city.

How will you do it?

There are lots of ideas about how to meet a growing energy demand. Here’s a chance to try out a few of your own.

Energyville is an online game that lets you choose from a wide range of energy sources to meet the demands of your very own city. Alternatives. Renewables. Oil. Gas. What should be developed? Is conservation the answer? What about safeguarding the environment? See the effect your choices have, then share those results with others.

Energyville is a lot more than just a game. It’s a chance to better understand and discuss the energy challenges we all face, then find the inspiration and know-how to solve them.

Put your ideas to work at willyoujoinus.com
Youth: crafting the future of the industry

The number of young people joining the industry or graduating in related areas has been steadily decreasing. Therefore, the petroleum industry is now on the edge of a demographic cliff, with an ageing workforce retiring shortly, and not enough young people finding the industry attractive enough to join.

This growing skills gap may impede the industry’s very ability to operate, especially with respect to major exploration and production projects. This challenge is particularly significant in the context of the world’s rapidly growing demands for energy and calls for greater adherence to responsible social and environmental practices.

Young people are the ones who will inherit the petroleum industry, and should be involved in crafting its future

In response to this challenge, the World Petroleum Council formed its youth policy, creating a Youth Committee in 2006, to bring a higher profile to the issue and form an alliance with young people themselves in order to find possible solutions to our challenges. We feel that it is important that young people are at the forefront of resolving this issue as they are the ones who will inherit this industry, and should be involved in crafting its future.

The Youth Committee prepared a programme of activities for young people at the 19th World Petroleum Congress in Madrid last year, including a special round table with industry leaders to discuss the question of “Does the industry need an image make-over?” They are leading the way in conjunction with other organisations and companies to address those issues, which are crucial to the next generation.

Our 1st WPC Youth Forum was held in China in October 2004, with over 500 young delegates focusing on “Youth and Innovation – the Future of the Petroleum Industry”. It played an important role in implementing WPC’s strategy to attract more young people to WPC activities and the petroleum industry.

We have now prepared the 2nd WPC Youth Forum, which is taking place in Paris from the 18-20 November 2009. Under the theme of “Energise Your Future” our young people have put together an innovative approach to the challenges and opportunities facing the oil and gas industry in the future. We need to move forward to engage young people in our industry and I call on everyone in the petroleum sector to give their full support to this endeavour and to mobilise their students and young professionals in order to energise all our future!
The cutting edge

Energy provides heat, light, power and mobility. We, our economies and our way of life depend on it.

Pythagoras, Galileo, Newton, Darwin, Pasteur and Koch, Marie Curie, Einstein, and Crick and Watson had at least one thing in common: they weren’t constrained by orthodox thinking.

You might argue that the idea of the lone scientific genius, whose leap of imagination redefines the way we see the world, is a function of the way we teach history: it’s easier to tell stories about people and dramatise single moments than to appreciate all the minute events and processes that led up to a great discovery.

It’s probably a bit of both. From a platform of scientific knowledge accumulated over centuries, a few people with the capacity to see the world differently have catalysed progress with moments of brilliant insight.

Successful oil exploration is about technology, data and science (and politics, geopolitics, economics and environmental law and so on). But it’s also about creativity, lateral thinking, ideas.

A decade ago, explorers in Brazil’s offshore went through a few lean years. Too few successful wells were being drilled. And the discoveries that were made were mostly too small to make development commercially feasible, given the high costs of operating in Brazil’s deep Atlantic waters and of producing the viscous, low-quality crude that was generally being found.

Brazil was a disappointment and some companies started to write it off.

But the doubts didn’t last. Since 2007, Petrobras and other companies have made a series of world-class discoveries that have turned Brazil into one of the world’s most coveted exploration plays. In the words of a former exploration and production chief of state-controlled oil company Petrobras: “We thought we were running out of oil, when actually we were running out of ideas.”

It’s easy to take the oil industry’s technology and infrastructure for granted. What we generally see is a fluid being pumped into the tank of our car — so the costs and technology involved in oil production are generally under-appreciated. We don’t see the vast distribution network — the pipelines, ships, lorries and trains that deliver oil to consumers worldwide at a rate of 150,000 litres a second. Or the platforms — staggering feats of engineering (see p53) — that produce oil from under the sea. Or the sophisticated technology that is needed to identify oil and gas deposits in the first place and bring the hydrocarbons safely and reliably to the surface. Given all that, it seems amazing that oil costs less by volume than, say, lemonade.

If all that’s generally taken for granted, so is what oil does for us. But oil is the common

denominator in much of what we do: somewhere along the line, it’s been involved in the production of the book you’re reading to the computer at home to the car in the driveway to the asphalt that coats the road outside. As well as gasoline, diesel and jet fuel, the oil industry is responsible for many of the products that define modern life — from heating and electricity generation, to the plastics that go into products ranging from medical equipment to children’s toys.

Without people finding and producing oil, life as we know it wouldn’t exist.

Oil exploration starts with three questions: is there oil and gas? How much? And is it economically producible?

**A picture of the subsurface**

Energy companies start to answer the first question by building a picture of the subsurface. Seismic data enable geophysicists to visualise what’s kilometres below the surface, layer by layer. Sophisticated computer-modelling software and phenomenal computing power — we’re talking 200 teraflops and 2,000 terabytes of data storage — can process that information into detailed 3-D images. Geologists, with their understanding of how the world was formed, can help determine the significance of structures identified by seismic studies — and speculate about whether they might contain oil.

Once wells have been drilled — vertically or horizontally — and steered remotely into carefully targeted spots deep inside the Earth, rock samples can be retrieved for analysis. And sensors can be placed down the hole to gather more information, using a wide range of measurements — electrical resistivity, radiation, ultrasound and others. Fibre-optic cables transmit the data to the surface where super-computers can analyse them, providing answers to the second question — how much oil and gas is down there?

Think about how robust that downhole hardware needs to be. The closer you get to the centre of the earth, the hotter it gets and the less like a lab; 5,000 metres underground, temperatures can easily hit 250°C and pressures 1,800 bar. Try putting your laptop in the oven.

The answer to the third question — what’s economically producible? — is largely a factor of technology, which is why energy companies invest so heavily in research and development. Twenty years ago, working in water depths of 3,000 metres and drilling to total depths of 10,000 metres were unthinkable. Today they’re a reality.
In another 20 years, those limits will have been stretched yet further. And technology will branch into new areas: perhaps nanobots will be able to go into the reservoir and say what’s down there. Or engineered bacteria will change the properties of, say, sticky oil — stuff that at the moment is incredibly tricky to retrieve — to make it flow better. Or sustainable biofuels will be made from fast-growing algae.

There are plenty of other ideas for energy supply in the future. Some are established, such as nuclear. Some are starting to make inroads in the market, such as wind. Some are commercially unproved, such as hydrogen fuel cells. And some are technologically speculative. But whatever the energy future holds, nothing can yet replace oil and gas at scale — and won’t be able to for decades.

Fossil fuels — deposits of oil, natural gas and coal formed over millions of years in the earth’s crust from organic matter — may retain their 80% share of the energy mix over the next two decades, estimates the International Energy Agency (IEA), a multi-government think tank. Even with the introduction of ambitious green policies, fossil fuels would still account for 67% of primary energy demand in 2030, according to the IEA. Oil will remain predominant “even under the most optimistic of assumptions about the development of alternative technology”, it says.

**Despite its hefty reliance on technology, oil’s not just a science endeavour**

That means greater innovation and ingenuity will be needed at oil companies — not just to find enough oil to meet incremental demand, but also to find enough oil to replace lost volumes as existing fields dry out. Even if oil demand were to remain flat to 2030, four Saudi Arabias will be needed by 2030 just to offset the effect of oil field decline, the IEA says. That’s a big challenge.

But despite its hefty reliance on technology, oil’s not just a science endeavour. It’s a business that depends on understanding and adapting to numerous other forces — politics, geopolitics, economics, environmental considerations, legal questions. Just looking at a map instantly gives you a feel for the political implications of, say, building a natural gas pipeline to Europe from the Middle East or Central Asia (see p106).

Then there’s the question of sustainability: consumers want cheap energy — and especially cheap oil, which helps to set the prices of all other commodities. But the same people want their energy to be clean.

That’s a contradiction politicians must grapple with. Renewables can provide clean power and there is no doubt that their contribution to energy supply is valuable and
will continue to grow. US President Barack Obama wants to launch a green revolution and to introduce sweeping legislation to tackle greenhouse-gas emissions. He calls his plan “America’s new energy economy” and says it will create millions of new jobs — and help lift the US and the rest of the world out of their economic difficulties. It’s certainly ambitious.

But bringing renewables into mainstream energy supply at the scale required to serve large populations is a difficult job and will take time. Biofuels, for instance, are a compelling idea, but there are strong arguments to suggest they don’t always make a positive contribution to the environment (see p114).

Meanwhile, as in Washington, most other governments also want to fight climate change too. In December, diplomats from 200 countries will meet in the Danish capital, Copenhagen, to try to thrash out a fiendishly complex global agreement on climate-change abatement. A great deal is riding on its success (see p40).

Like the technical solutions, the policy ones depend on creative thinking. The simplest, cheapest and most effective way of reducing the environmental impact of energy use is to become more efficient in the way we use it — in buildings and cars (see p20), for example. But numerous laws, incentives and regulations are needed to make better habits take root.

Another priority is decarbonising the power sector, capturing and storing CO₂ produced in electricity generation (see p94). But that costs money: who will pay for it? There are plenty of other ideas, including cap-and-trade schemes (see p111). But the right degree of government intervention and financial support is necessary to get these fledgling ideas off the ground.

Things are changing, and fast. The world’s most dynamic industry is used to that. But the challenges ahead are greater than ever before: it makes 2010 and the next few years crucial for the energy sector. And the world.
Profile — Yasmine Wattebled

Name: Yasmine Wattebled
Company: Total
Present job: Petroleum installations engineer
Age: 32
Nationality: French
Degree: Engineering diploma, Ecole Centrale de Lyon; Master's in environmental fluid mechanics, Stanford University

I joined Total’s graduate-training programme in 2003, after spending my first year after university working for an environmental consulting firm in San Francisco, on a water-supply project.

Total’s programme consists of three two-year assignments in different disciplines — giving you a firm base for career development and choice. I started as a process engineer, based in Paris, assisting in the design of the topside facilities of petroleum platforms — everything that sits on the deck. That includes the oil and gas treatment units. Hydrocarbons must be treated immediately after production so they can be safely transported and so that they meet commercial standards. We’d design equipment then evaluate the costs to see whether the solution we’d come up with was economically viable.

It was tough a first; I had little prior knowledge of the petroleum industry and had to learn quickly. But my department was dynamic and senior staff helped me acquire the technology, skills and knowledge I needed. I felt a real sense of belonging — one of the things I most appreciate about Total.

In 2005, I became a production engineer on a platform offshore Congo. That was a fantastic experience; you’re living with 160 people, in a close-knit community, 80 kilometres from the coast, shuttling to and from the mainland by helicopter. We saw dolphins, whales … it’s the only time I’ve had a sea view in my office and bedroom!

The job was on a rotational basis: four weeks on and four weeks off. Having every other month off gave me an incredible sense of freedom — like having a second life. I’d go home to Paris or go travelling.

The operational side was really exciting too: you learn so much on site. I was tasked with developing ways of optimising the production process to boost oil and gas output and my process-engineering placement was invaluable experience.

I was able to reduce greenhouse-gas emissions from the platform by one-third, which was very satisfying. Given my first job and the nature of my degree, good environmental stewardship is important to me. If you want to have an impact on the environment — by minimising gas flaring or improving the quality of produced water, for example — you can really make a difference working for an energy company.

In 2007, I was put in charge of a project to build a new camp — houses, restaurants, offices and recreation facilities — to accommodate 260 people working at an onshore gas plant. I’m handling the contractual and commercial negotiations — liaising with suppliers and contractors and managing engineering. It’s a completely different challenge. You’ve got to get what you want done, which isn’t always easy. I’m Paris-based, but travel to Nigeria frequently.

It’s amazing how many disciplines the petroleum industry covers. There’s the technical side — safety, process, mechanical, electrical engineering and so on. But you can go in plenty of other directions — project management or economics, for instance. You never get bored. You’re always learning. And you’re at the heart of geopolitics, working in an international and culturally varied environment. It’s invigorating.
Industry facts

Oil: $30-150
Trading range of crude oil from mid-2008 to mid-2009

Gasoline: $111 USA
$162 Australia
$275 France

Water: $350 USA
$560 Australia
$190 France

What a bargain!

Source: The prices of the products listed here can vary, depending on the outlet, but are indicative of those generally being charged at popular supermarkets, stores and filling stations in each country at the time of going to press. Research conducted in mid-2009.
Industry facts

**Milk**
- $335 USA
- $290 Australia
- $335 France

**Cola**
- $160 USA
- $240 Australia
- $205 France

**Chanel No 5**
- $190,000 USA
- $280,000 Australia
- $230,000 France

**EDITOR’S OBSERVATIONS:**
- The 12 months from mid-2008 to mid-2009 show how much the price of oil can vary: from about $150 a barrel in mid-2008, to $30 six months later, to $70 in mid-2009.
- Planning isn’t easy if the main commodity you sell is capable of suffering an 80% loss in value in six months.
- Oil prices at $150 a barrel – and even $70 a barrel – are high by historical standards. But profitability depends on how much it costs to extract it from the ground. Oil prices help define the cost of many other commodities and materials used in energy production, such as steel. So higher oil prices = higher costs.
- Oil and gasoline remain compelling value compared with a variety of other liquid commodities, even at mid-2008 prices – when you consider the technology and investment required to produce them and what they can do for you.
- Gasoline costs less in the US than in Australia or France because Americans enjoy relatively low levels of taxation on gasoline.
- Perrier is a drink best drunk in France.
Think globally

What are employers looking for and what can a career in energy offer? How the Energy Industry Works (HEIW) talks to recruitment experts at BP, Chevron, Schlumberger and Tenaris

HEIW Why should young people consider a career in the energy business?

E H-J I would really struggle to think of another career that gives people access to such a wide and exciting range of opportunities. And the issues involved in energy are so varied — political, environmental — that it has an impact on everyone’s life.

ES One of the amazing things about the petroleum industry is how many different careers there are and how people can come in with similar credentials and end up taking up very different career paths. With the industry in great flux and firms looking at different forms of energy — such as biofuels, geothermal, wind and solar — it’s particularly hard to predict which way young people will head.

The industry’s scope is a great advantage in allowing you to adjust your work-life balance as your priorities change. If, for example, you have children, you could have the option of switching from an operations to an office role. In a big energy company, you can move laterally, or sometimes even up, into drastically different functions, and learn and take on new careers without the penalties — such as a setback in salary, for instance — that you could incur in switching industries.

I’ve always loved the opportunity the industry presents to live and work around the world, getting to know and work with people from different cultures, solving common problems. It changes how you see the world.

LJ It is an intellectually and professionally stimulating environment. Energy is one of the main drivers behind the world’s economic and political development. And many jobs in the sector involve designing and deploying state-of-the art technology to meet the world’s increasing energy demands in a safe and environmentally friendly manner.

HEIW What are you looking for in applicants?

E H-J It’s true that we’re looking for technical excellence, a strong intellect and analytical skills, but the things that make a big difference to us are flexibility and mobility. Can candidates cope with the fast-paced change in our activities? Do they have passion and drive — for their technical subject and the broader business? Are they passionate about learning, new technologies and their personal development?

ES It’s critical thinking — to be able to think for yourself: breakthroughs in energies of the future will come from someone coming up with a new technical concept, a new business model.

Communication and interpersonal skills are also essential. You have to be able to work in teams with different skill sets that are typically multi-national, multi-cultural and multi-technical. If a geologist has to talk to an engineer, that’s a communication barrier.
Throw on top of that the fact that they may not share the same first language and the problem has become more complicated.

**LJ** We look for the best candidates in schools, both men and women, who strike a good balance of technical competence and open-minded personality. Because our jobs are unique in terms of geography, lifestyle and career progression, it is critical to identify people who are willing and suitable to join our team.

**GL** We are looking for candidates who have proved academic excellence and a strong level of English. They should be interested in developing a career in a global company and the geographic mobility that often comes along with it.

**HEIW** What degrees are you looking for?

**E H-J** We have 17 different disciplines and some have a clear requirement for a specific qualification, such as chemical engineering. But students could come from a range of numerate backgrounds — including mathematics, physics and broader engineering disciplines. We also hire people into other areas, such as trading, where people could come from any discipline. If they use our website’s degree matcher, potential recruits might be quite surprised about the breadth of applicable degrees and career options available.

**ES** It’s a very long list. Chevron hires across all the disciplines — petroleum engineers, geologists, IT experts, MBAs, mechanical engineers, chemical engineers, civil engineers, HR experts, environmental specialists, lawyers, communications specialists.

The divisions between traditional roles are becoming more blurred. Many different kinds of engineers can and do work in petroleum engineering. Many drillers, for example, are mechanical engineers; chemical engineers work as reservoir engineers — because, in essence, the job involves working with fluids moving through materials, whether in the subsurface or above ground.

Also, more things that would classically have been referred to as refining are happening in the field — heavy oil is being upgraded closer to the field to improve the economics. It’s similar with natural gas: how you transport it is an integral part of the development question, so that requires commercial skills as well as the chemical-engineering understanding of how the gas will behave under different temperatures and pressures.

This all means a range of disciplines are applicable to the multitude of career paths.

Most of the engineering and sciences we can use — IT, physicists, mathematicians, instrumentation experts, electrical engineers. And even those with biology degrees, given the environmental work we have to do. You might not have thought it, but we even need doctors and healthcare professionals — you can have a considerable medical establishment within an oil company.

One profile that is particularly sought after is the engineer with strong computer skills. They have a critical role to play in the advancement of the intelligent oil field.

**LJ** Typically, the bulk of recruitment is engineering and science graduates. Some people think we only hire engineers, but we do also hire from the sciences, such as earth science, physics and mathematics.

**GL** We are looking for mechanical, industrial, electrical and material engineers.

**HEIW** What advice would you give candidates preparing for interview?

**E H-J** The thing we see candidates perform least well at is in their ability to apply technical knowledge in a work environment. We see candidates who are clearly bright and have excelled academically. It is important to spend some time reviewing what they’ve learned from their degree and how that translates into real life. Most people will have some experience to build on from research projects or internships.

We often interview people who are monosyllabic and don’t give us sufficient infor-
mation about themselves. It’s important to think about how to demonstrate the value of learning and experiences, but I expect that fewer than half our candidates have read the hints and tips section on a website dedicated to the application process.

Also, students can sometimes be reticent about activities that aren’t related to work or university. We are keen to hear about those activities, because they can often demonstrate whether candidates have the personal qualities we are looking for.

Candidates should also be using the interview to find out about us — asking the right questions shows that they have done their research.

**LJ** Do your homework on the company that is interviewing you. At the interview, be honest and be yourself. Interviews are a two-way process, designed to assess from both sides the suitability of the candidate for the job.

**GL** To get the most from your interview, you should read the information available about our company and its training and development programmes on our website: www.tenaris.com.

**HEIW** What career paths are available?

**LJ** The options are endless, really. For example, in Schlumberger, if you are looking for a technical career in operations, you can start as a field engineer, or in a petrotechnical role. Starting in the research, engineering, manufacturing and sustaining group is also an option. You will spend the first few years learning about the technologies and services in your technical discipline, after which your career can take off in a wide variety of directions. Another starting point can be through personnel, finance, legal or supply chain management. You can also move across all of the jobs mentioned earlier.

**GL** We have open positions in a variety of areas, but the majority of our demand is focused on industrial operations, as well as the technical sales, maintenance, supply chain and engineering departments.

**HEIW** What other advice would you give young people considering a career in the energy industry?

**ES** In times of intense competition for people, there tends to be the illusion that the company will be responsible for plotting out the individual’s career. But no-one can really do that for you: a company can lay out a career plan, but it can’t predict the future or how someone’s personal interests will develop.

The person who cares most about your career is you and you should never abdicate responsibility for defining it.

**LJ** If you like to embrace change, think globally, understand best-in-class technology and be part of a hard working team, then there is no need to think twice!

**GL** The energy industry is going through a period of unprecedented change. Global companies are forced to move beyond the traditional areas of operations to explore and develop new reserves located in remote regions and in difficult environments. Tenaris is working to be a partner to these companies, developing new products and services for complex projects. Someone looking to work with us or in any company linked to the energy industry must have a drive for creativity and possess innovative problem-solving skills. He or she must also be proactive in the search for knowledge, learning about the latest trends in the market.
COLOMBIA: The perfect environment for Hydrocarbons

Open Round COLOMBIA 2010

START THE DECADE WITH THE BEST INVESTMENT OPPORTUNITIES

This year the best investment, exploration and production opportunities for hydrocarbons will be in Colombia. The Colombia National Hydrocarbons Agency, ANH, shall offer areas for Special TEAs*, E&P and MiniRound in 2010.

The Colombian Government and the ANH cordially invite you to the Open Round Colombia 2010 ROAD SHOW, that will be held on:

ROAD SHOW

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*Technical Evaluation Area

Tentative Agenda

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www.colombiaround2010.com
COLOMBIA EMERGES AS REGIONAL OIL HUB

With upstream growth continuing despite the recession, Colombia is transforming itself into a regional hub for oil-industry services.

Oil and gas exploration and production (E&P) activity in Colombia has held steady despite the international financial crisis, according to Colombia’s upstream regulator, Agencia Nacional de Hidrocarburos (ANH). And momentum is building: national crude oil production should end 2009 at 700,000 barrels a day – around 20% higher than at the end of 2008. And robust growth is set to continue: by 2015, Colombia should be producing 1 million barrels a day (see Chart 1).

Upstream momentum is building
Chart 1. Colombia’s crude oil production

Source: ANH
THE ONLY WAY IS UP
Proved reserves are on an upward curve too, rising from 1.4 billion barrels at the end of last year to 1.7 billion barrels. But given that the country also produced 200 million barrels over the intervening 12 months, it achieved a total gain in reserves of 500 million barrels – and a healthy reserves-replacement rate of 250%.

It is a far cry from the late 1990s, when, with high political risk and unattractive terms deterring investors, Colombia was in danger of becoming a net oil importer. Under Alvaro Uribe’s presidency, a competitive taxation regime, declining crime and terrorism rates, and a growing reputation for legal stability and contract sanctity have boosted business confidence. Indeed, despite the recession, says Zamora, foreign direct investment in the petroleum sector could match last year’s total, of $3.5 billion (see Chart 2). With national consumption of around 300,000 barrels of oil a day, exports are substantial. The petroleum sector is the largest contributor to export income and the biggest source of foreign investment. And although the Colombian economy isn’t dependent on oil – the sector accounts for just 4% of GDP – exports are set to rise sharply, as the country ramps up production.

Such has been its success in attracting investment that ANH now sees the country as a regional hub for services to the wider region’s petroleum industry. Says Zamora: “Colombia has a number of industrial centres and tax-free zones with excellent locations for the oil field services industry and it is becoming a regional centre for the oil and gas industry.”

The long-term outlook for upstream growth is good, too. Reserves could rise to 4 billion barrels by 2020, says ANH. Ecopetrol, the state-controlled oil company, estimates the country’s resource potential at 47 billion barrels of oil equivalent. Some of the upside will come from improving recovery rates at existing fields, but there is considerable scope for new exploration.

EXPLORATION INTENSIFIES
Despite the recession, licensing and exploration activity has remained robust: Zamora expects Colombia to sign about 60 exploration and production contracts this year, which would put it level with 2008. The agency also expects explorers to drill a similar number of exploration wells in 2009, compared with 2008 – a record year. Growth should also resume over the next 12 months: firm, contractual commitments for seismic acquisition and drilling for 2010 are around 60% higher than for 2009, says Zamora. Meanwhile, Colombia continues to push into frontier areas, as its extensive offering under the 2010 licensing round shows (see map on following page).

Investment holds firm despite recession
Chart 2. Foreign direct investment in Colombia’s petroleum sector

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Source: Central Bank
Up for grabs are rights to 74 small blocks, being auctioned in a mini-licensing round (Type 1 – see map). In addition, ANH is offering 31 licences termed E&P Newly Prospective Basins (Type 2) and 63 Special TEA licences (Type 3). TEAs are technical evaluation licences – short-term contracts that allow areas of interest to be evaluated for prospectivity without committing explorers to expensive drilling programmes. Overall, ANH hopes to license 168 blocks, spread over more than 50 million hectares of territory. The agency will officially launch the round in December 2009, taking a roadshow to several of the world’s biggest oil cities, and aims to sign up new exploration partners in the second half of 2010.

ANH is also expecting good news from relatively unexplored areas already under licence, such as the heavy-oil region near the border with Venezuela and gas-prone basins off the Caribbean coast (see box). There are good reasons for optimism: about 70 discoveries have been made in the past five years with around half the wells drilled finding hydrocarbons. And much of the country remains unexplored.

COLOMBIA SEES FUTURE AS MAJOR GAS EXPORTER

Colombia could soon have proved up enough gas to emerge as a major exporter, says Agencia Nacional de Hidrocarburos (ANH). As several big oil companies prepare to drill wells in gas-prone deep-water areas off Colombia’s Caribbean coast, ANH says there’s potential for one or more liquefied natural gas (LNG) terminals. “It’s just a matter of time before we are confident enough to move into a totally new stage of our gas industry, which is to open up for exports,” says Armando Zamora, ANH’s director general.

Proved gas reserves, if used at the present rate, would last just 20 years, so there has – understandably – been some opposition to export schemes. But Zamora believes exploration success will soon render such objections redundant. Colombia’s Caribbean waters are predominantly gas prone. The region’s Guajira gas field, the country’s main source of gas, has been producing for over 30 years. And a recent study by Halliburton suggests that the area – which includes the Chevron-operated Chuchupa, Ballena and Riohacha fields – may contain up to 50 trillion cubic feet of gas. Exploration will start in earnest next year, with five wells expected in 2010. Companies with acreage in the area include BP, Petrobras, Ecopetrol, ExxonMobil, Hess, ONGC and BHP Billiton. There have been onshore successes too. This year, Hocol and its partners, Talisman Energy and Tepma, made a “significant gas condensate” discovery in the Andes foothills, 300 kilometres northeast of Bogotá, which could signal the presence of a new hydrocarbons province in the middle of the country.

Colombia could also become a significant part of the unconventional gas revolution. The country has “several trillion” cubic feet in shale-gas deposits north of Bogotá, as well as large volumes of gas trapped in coal seams in the northern Guajira basin, says ANH. Colombian gas production amounts to 1 billion cubic feet a day, with 70% consumed locally and the remainder piped to Venezuela.
The car of the future

The car of the future could run on batteries, hydrogen fuels cells or biofuels. But, for decades, it will be difficult for anything to replace gasoline and diesel at scale.

Imagine driving once around the planet on 13 litres of fuel. Yes, that’s right: 13 litres, 40,000 kilometres — and a cost of just over $9 (at US prices in mid-2009).

If the roads existed (and there were bridges over the seas — admittedly all rather hypothetical), it could be done: in 2004, a combustion-engine entry in Shell’s Eco-marathon — an annual competition that challenges students to design, build and test vehicles that go further on less fuel — achieved a projected 3,140 kilometres on the equivalent of a single litre of fuel.

Compare that with the fuel economy of cars in general use: even Toyota’s Prius, the most economical car rated by the US Environmental Protection Agency’s fueleconomy.gov website, would travel just 20 kilometres on a litre of gasoline.

Of course, the futuristic cars of the Eco-marathon, with their bodywork streamlined to minimise drag, aren’t practical; they couldn’t carry shopping or passengers, they’re too slow and they don’t have the conveniences and safety features of a modern car.

But they show that, through design and innovation, significant efficiencies can be achieved in fuel consumption — saving precious resources and cutting back on carbon. That’s important because transportation accounts for around 15% of the world’s greenhouse-gas emissions, according to the World Resources Institute, an environmental think tank.

It’s also important because, despite all the excitement surrounding electrical and hydrogen vehicles, gasoline and diesel will be needed for a long time. Even if it were a realistic prospect, getting rid of the internal combustion engine wouldn’t necessarily be a desirable one. Electric cars, for example, might not produce emissions when they’re operating, but if their batteries are charged with electricity generated in a coal-fired power station, then it could mean more, not less, carbon dioxide (CO₂) in the air.

The internal combustion engine has a lot going for it. With petroleum products such as gasoline and diesel you get more bang for your buck: no other fuel source comes close to matching their energy density (see p117).

The need for liquid fuels produced from fossil fuels is especially great in heavy engines, because petroleum’s juicy energy content is better equipped to deal with high workloads than alternatives.

Then there are the many complexities involved in shifting to a completely new concept in automotive power: the internal combustion engine has been around for 100 years and we’re used to it. And we’re used to providing the fuels and operating the in-
2.1 — Transportation

Transportation infrastructure — ships, lorries, pipelines and filling stations — on which it relies. Although being accustomed to one way of doing things is, in itself, a weak argument against exploring alternatives, it would certainly be difficult and costly to move to a completely new system — and it would take a long time.

The problems with petroleum

But petroleum has its drawbacks too: stricter laws governing the output of CO₂ and other greenhouse gases are today’s cars’ biggest problem. As the cost of emitting carbon rises, alternatives to the internal combustion engine will become increasingly attractive economically — unless, perhaps, energy companies discover a cheap way of producing very large volumes of renewable biofuels that can be used harmlessly in the engines in use today. Companies behind the nascent algae revolution think that might happen one day, but it’s an uncertain prospect (see p78).

Then there’s the repair system to think about, says Julius Pretterebrner, a car-industry analyst at IHS Cera, a consultancy. With all of its many and intricate moving parts, the internal combustion engine needs a large maintenance network. That’s one area in which the electric car wins hands down, he adds: apart from the driveline, it doesn’t have much in the way of moving parts. That means considerably less wear and tear, less maintenance and no need for a complex support industry.

Fuel standards in liquid fuels — for oil products and biofuels — create problems for car manufacturers too. Because they vary from region to region and, often, from country to country, it’s impossible to produce a one-size-fits-all engine. That puts costs up. Adapting an electric vehicle to a different market is simple: all you need is a plug adaptor and, possibly, a transformer.

There’s also the question of efficiency. The internal combustion engine is typically...
only about 20-30% efficient. Lower perhaps: according to fueleconomy.gov, only about 15% of the energy from the fuel in the tank is used to move the car or run useful accessories, such as air conditioning. The rest of the energy is lost to engine and driveline inefficiencies, and idling. And drivers rarely get the best out of their cars: an internal combustion engine optimised to 200 horsepower won’t work at its best crawling through heavy traffic, so, in the city, efficiency slumps — it’s the inverse of trying to heat a room with a hairdryer. Emissions performance also deteriorates at lower work rates.

But poor efficiency ratings at least mean there’s room for improvement.

What can be done to make existing cars more efficient? Various technology developments will help cut down on fuel use. Cylinder deactivation, for example, shuts down some cylinders when less power is required. Modern engines can also be designed to alter valve timing — varying the quantities of air and fuel entering the cylinders and enabling fuel savings when power needs are low.

Hybrid cars — bi-fuelled vehicles that can switch at different speeds between a gasoline-burning internal-combustion engine and an electric motor powered by a rechargeable battery — can achieve significant efficiency improvements over cars with standard engines. The electric motor — recharged with kinetic energy that is normally lost to braking, with a system called regenerative braking — means the gasoline engine isn’t needed when the car has stopped or when it’s travelling at low speeds. The gasoline engine, meanwhile, is there for higher speeds and to overcome the limited driving range of an all-electric vehicle.

Doing the obvious stuff

There are plenty of straightforward efficiency measures too, such as reducing the size and weight of vehicles. Today’s VW Golf, for example, is almost twice as heavy as the first Golfs, built in the 1970s. That’s partly because of the addition, over the years, of safety features, such as the protective metal bars in the doors of modern cars. It’s also partly down to a perceived need for more room: the smallest cars in BMW’s range today — the 1 Series — are similar in size to the BMW 2002; but in the 1970s, the 2002 was considered a roomy, desirable family vehicle.

The weight increase is also the result of the proliferation of electronic gadgets and modern conveniences. In some areas that trend will continue: there won’t be any compromise on safety, for instance. Indeed, carmakers are continuing to add safety features; electronic stability control, a computerised technology that improves a vehicle’s handling by detecting and preventing skids, is among the latest innovations. But what about the non-vital stuff? Air conditioning systems, for example, are heavy: could people do without them?

Have you seen how low my carbon emissions are?
The 2007 Ford Fiesta emits less than 2% of the nitrogen dioxide, hydrocarbons and carbon monoxide produced by its 1976 predecessor, according to the UK’s Society of Motor Manufacturers and Traders (SMMT). It would take the following numbers of 2007 1.25 gasoline-engined Ford Fiestas to generate the same level of tailpipe emissions as one similarly sized 1976 Fiesta model, calculates SMMT:

- Nitrogen dioxide — 76 cars
- Carbon monoxide — 71 cars
- Hydrocarbons — 51 cars

Average UK new-car CO₂ emissions

<table>
<thead>
<tr>
<th>Year</th>
<th>CO₂ emissions (grammes per kilometre)</th>
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</thead>
<tbody>
<tr>
<td>1997</td>
<td>200</td>
</tr>
<tr>
<td>2007</td>
<td>150</td>
</tr>
<tr>
<td>2008</td>
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Source — SMMT

Passenger cars’ emissions in the UK

<table>
<thead>
<tr>
<th>Year</th>
<th>Nitrogen oxides (million tonnes)</th>
<th>Carbon monoxide (million tonnes)</th>
<th>Particulates (million tonnes)</th>
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<tbody>
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<td>0.5</td>
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<tr>
<td>2006</td>
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<td>2.0</td>
<td>1.0</td>
</tr>
</tbody>
</table>

Source — UK Department for Transport
2.1 — Transportation

Smaller, greener, cooler

Taste in cars could become more modest too. Four-by-four cars, pick-up trucks and sports-utility vehicles (SUVs) are status symbols for many people. But, perhaps, as the world tries to turn itself green, smaller, more economical vehicles will become cooler: emissions levels might become more of a talking-point than horsepower. Car-pooling and car clubs could become more popular, reducing the number of vehicles on the roads. Indeed, there’s scope for cutting the sheer number of cars: the US has more passenger vehicles than licensed drivers.

There are plenty of signs that tastes are changing. The crisis that threatened the survival of the US car industry in 2008 and 2009 is, to a large extent, down to US manufacturers’ failure to keep pace with Asian firms, which have focused on fuel-efficient cars.

Innovative use of materials — aluminium, thin-walled steels, plastics and composites — would also make cars lighter. Toyota’s 1/X concept car, a natural gas/electric hybrid that uses plug-in technology, weighs just 420 kilograms, but has as much interior room as the Prius, which has a kerb weight of 1,300 kilograms. The 1/X’s frame is mainly carbon-fibre reinforced plastic — strong, but light.

Rethinking the way cars are designed could radically improve efficiency: innovative use of materials would make cars lighter such as hybrids. Sales of SUVs and other gasoline-guzzlers have been waning in the US and the number of small, more fuel-efficient models is on the rise. In India, the popularity of Tata’s Nano mini-car indicates the trend towards smaller, lighter — and cheaper — vehicles is occurring elsewhere too.

Innovative use of materials — aluminium, thin-walled steels, plastics and composites — would also make cars lighter. Toyota’s 1/X concept car, a natural gas/electric hybrid that uses plug-in technology, weighs just 420 kilograms, but has as much interior room as the Prius, which has a kerb weight of 1,300 kilograms. The 1/X’s frame is mainly carbon-fibre reinforced plastic — strong, but light.

Smaller, lighter cars will lead to reduced fuel use — and lower carbon emissions. And this should be possible without compromising safety: Formula One cars are made from carbon-fibre composites and similar ultra-lightweight materials, but drivers often walk away from high-speed crashes thanks to sophisticated crash inserts.

It’s not as if lightweight cars are new, either, points out Pretterebner. East Germany’s much-maligned Trabant might not have looked cool and would have looked a lot less cool after a collision, but its designers — admittedly focused on cost savings rather than fuel efficiency and safety — were arguably on the right lines with materials: much of the bodywork was plastic.

Rethinking the way cars are designed could radically improve efficiency — enabling the world to continue to benefit from the power and versatility of the internal combustion engine at a reasonable environmental cost. And, in the very long term, innovations being made today can be used in other forms of transport. Lighter materials will also be of benefit to the electric car industry: less weight = less work = longer battery range.

The electric car: pros and cons

If India’s Tata — or another manufacturer in the high-growth, electronics-savvy Asian market — were to start mass marketing an electric version of its cheap and popular Nano mini-car, it could begin to give the electric car industry and the technology behind it the economies of scale it needs to flourish.

Batteries are one of the main problems. They’re heavy — 800 kilograms for the average car, according to Vanessa Guyll, a technical specialist at the UK’s Automobile Association — and their range is, in most cases, underwhelming. There aren’t enough recharging points and most electricity grids would need significant investment before
they’d be able to cope with millions of drivers plugging in their vehicles at the same time. And unless the electricity comes from a low-carbon source, such as solar panels, wind turbines or biogas, then it won’t mean mobility without emissions.

Lithium-ion batteries, which are smaller and have a greater energy density than the nickel-metal-hydride batteries used in hybrid cars such as the Toyota Prius, have the potential to improve range. However, it won’t necessarily be a smooth journey. Lithium-ion batteries can explode if they overheat: not a comforting thought as you’re belting down the freeway. They’re also expensive, costing four to five times more than the nickel-metal-hydride variety, and gradually degrade with use.

Tesla, a US electric-car manufacturer, says it’s getting round the overheating problem with a special cooling system for the 6,831 lithium-ion cells under the hood of its $100,000 Roadster.

There are other reasons for the Tesla Roadster’s high price tag — and they’re more encouraging for the electric-vehicle industry. With acceleration from 0 to 60 miles per hour in 3.7 seconds and a top speed of 125 miles an hour, it is a high-performance vehicle — a rival to gasoline cars. It has a US Environmental Protection Agency efficiency rating equivalent to 135 miles per US gallon, making it almost three times as efficient as a hybrid vehicle. And one full charge should last something like 350 kilometres.

One disadvantage is that, from dead, it takes about three and a half hours to charge the battery — not as quick as pumping 50 litres of gasoline into a tank. Tesla says it’s rarely likely to take that long because the battery will seldom run down completely before its overnight recharge. While that may be the case for everyday urban use, the car would certainly not be as practical for long journeys or to places without access to electricity.

The Tesla has another advantage: it looks like a car you might want to drive. Electrically powered milk floats may have been on the road for decades — since 1920s in the UK — but you wouldn’t want to go to work in one, unless you were a milkman (even then you might not — editor).
Hydrogen power: pros and cons

As an electricity-generation system, the great advantage of a hydrogen fuel cell is that its waste product is water, so in theory it’s zero carbon. But things aren’t that straightforward. Hydrogen doesn’t occur naturally in great quantities so it has to be manufactured. Energy used in the manufacturing process could generate emissions and if it’s reformed from a fossil fuel, then that would add to the carbon footprint.

There are other drawbacks. Fuel cells aren’t yet robust enough to tolerate the rough treatment they’d get in a car. They’re heavier than batteries and more complex — so more can go wrong with them and they’re more expensive to buy and maintain.

Hydrogen, meanwhile, is a volatile gas, making storage and transportation tricky. One possible way around the problem is to fill the tank with natural gas and reform it on board — safer than carrying round a tank of compressed hydrogen. But an on-board reformer is a complex piece of kit — like driving around with a refinery in the back of your car — which adds to the up-front and running costs.

Biofuels: pros and cons

One of the big advantages of biofuels is that they can be used in existing car engines, so increased use of biofuels wouldn’t require the renewal of the car fleet. Distribution networks wouldn’t have to change radically either: they are already handling large volumes of biofuels.

Ethanol is in widespread use around the world as an alternative to gasoline. It’s been especially successful in Brazil, where all gasoline contains a 25% ethanol blend. In addition, the widespread use of flex-fuel cars, which can run on any mixture of eth-
anol and gasoline, means ethanol accounts for more than half of the automobile fuel market in the country.

But Brazil, the world’s second-biggest ethanol manufacturer, has the right climate and enough land to grow large amounts of sugar cane. Few other countries share those natural advantages. The US is the world’s biggest ethanol producer, but the feedstock it uses is maize (called corn in the US), which is a much less efficient biofuel crop than sugar cane — eight-times less efficient, according to Brazilian oil company Petrobras.

The downside

Ethanol also lacks gasoline’s energy content, falling about 30% short. Biodiesel compares more favourably to conventional refinery diesel in terms of energy content, but it’s a living fuel — store it under the wrong conditions and it will go rancid. That adds another layer of complication — and cost.

There are other problems. Fuels containing a high proportion of ethanol or biodiesel tend to cause starting problems in cold weather. And ethanol is corrosive, making it difficult to transport. Perhaps most serious of all, land used for growing crops for fuels is land that can’t be used for growing crops for food; so biofuels cultivation presents a threat to food production and may cause inflation in food prices.

There’s hope that second-generation biofuels, such as those produced from algae (see p78), or biomass (see p118), will significantly mitigate these problems by harnessing crops that grow on land that wouldn’t be suitable for food crops and by converting non-edible parts of plants into energy.

Another promising biofuel is biogas — typically gas produced by the biological breakdown of organic matter in the absence of oxygen. Maize, for example, yields more energy per unit of area if it is treated to produce methane, as opposed to ethanol; according to IHS Cera, a car can drive 60,000 kilometres on biogas produced from one hectare of land, but only 40,000 km if ethanol is produced from the same area. That gas could either be used to power internal combustion engines or as a low-carbon system for producing electricity that could then be used to power electric car fleets.

Natural gas: pros and cons

Compressed natural gas (CNG) is a good fuel for cars in cities because natural-gas vehicles are silent and cause less pollution than cars that run on oil products. According to the US’ Environmental Protection Agency, compared with traditional vehicles, those operating on CNG have reductions in carbon monoxide emissions of 90-97% and reductions in CO₂ emissions of 25%. There are also significant reductions in emissions of nitrogen oxides and virtually no particulate emissions.

But there are drawbacks: most car engines aren’t optimised for gas use. Refuelling networks haven’t been developed on a wide enough scale to make natural gas vehicles practical for most people. And the need to sacrifice valuable trunk space to accommodate the gas tank also rules out this type of car for many private users.

The shortage of refuelling points means natural gas is generally suited to city-bound vehicles — taxis and buses — which can refuel at a central point at the end of the day. There are almost 10 million natural gas vehicles worldwide — almost half of them in South America. The International Association for Natural Gas Vehicles projects that this will increase to 50 million vehicles, by 2020.

Environmental performance improvements can also be achieved compared with traditional refinery fuels by using liquid fuels produced from natural gas.
Oil prices: not too high, not too low

Q So oil’s cheap again, right?
A What do you mean by “cheap”?

Q Well, I’ve read everywhere that there was a crash in oil prices last year. So it’s affordable again now, right?
A What do you mean by “affordable”?

Q I’m supposed to be asking the questions here.
A I’m not trying to be cryptic. But the first thing you need to know about the oil market is that categories like “cheap” and “affordable” are relative. If I tell you it’ll cost $2 to drive you and three friends seven miles down the road, that sounds pretty cheap, right? That’s about what it costs at the moment, based on where oil prices are.

But if I tell you that a barrel of oil this summer cost about 25% more than its historical average price, it seems expensive, right? But then what if I tell you oil prices towards the end of 2009 have been changing hands for less than half the price they did last summer? Cheap. See what I mean?

Q Er … I think so.
A There are other reasons to think oil prices are cheap. In autumn 2009, they were hovering around $65-72 a barrel. But consider everything you have to do to extract one barrel of the stuff. In west Africa, the big oilfields sit thousands of metres beneath the seabed. And the water’s deep. It costs billions of dollars to develop a big oil project there.

Or look at Canada, where the world’s second-largest oil reserves are trapped in billions of cubic metres of sand in northern Alberta. You have to shift two tonnes of sand just to produce one barrel of oil. And the company gets just $70 in exchange? That seems like a bargain for the buyer — especially when it costs about that much for the producer to extract a barrel of crude from the tar sands in the first place.

Q So if the companies have to spend so much to get the oil in the first place, why don’t they just raise the price of oil?
A Well the short answer is that they sell oil in a market place and don’t set the price — buyers do by competing with other buyers. But it’s more complex than that.

Think of it this way: the developed world’s economy is an oil economy. We rely on oil for almost everything we buy, sell, make or eat. The richer we get, the more oil we consume — and vice versa. But — and it’s an important but — because we rely so heavily on a steady stream of oil (about 84.5 million barrels a day in 2008), the global economy

It costs billions of dollars to develop a big oil project
can suffer if crude prices rise as they did last summer. It’s basic supply-and-demand stuff: when the commodity gets too expensive, people stop buying it. So oil companies, or producers, have to tread a fine line. They spend hundreds of billions of dollars up front, so if demand for their product falls, so do their profits. It’s in their interest to keep the oil flowing at affordable prices.

Q So when oil prices hit their record of more than $147/b last year, people stopped using oil?
A Again, not so simple. Demand for oil can fall — as it has for the past two years — but only so far.

But the oil market does react very quickly to changes in demand. Last year’s bumper prices persuaded people to be more efficient — everything from pumping up the tyres on the car to make it go further on a litre of gasoline, to selling the SUV and buying a bike — and prices fell quickly in response.

Q What have speculators got to do with price rises?
A Okay, hold steady, because it gets even more complex now. People don’t just trade barrels of crude oil. They trade bits of paper that promise delivery of barrels of crude oil at a given time. So some clever investors looked at the oil market in recent years and decided that it was a one-way bet. China and India were surging and gobbling up spare oil, the economies of the West were ticking along nicely, and many oil producers were struggling to keep up. It looked like oil prices would rise indefinitely. So these investors started buying paper contracts, holding them for a time while the oil price continued rising, and then selling them for a profit. You had two upward forces on the market: one connected to the “fundamentals” of weak supply versus strong demand; and one relating to investors buying paper contracts and pushing the prices up even further. It got pretty crazy.

Q And then it crashed.
A Yes. The credit crunch happened and all of a sudden everyone started feeling a whole lot poorer. The idea that the world would keep growing richer and needing more oil disappeared. A lot of the speculators were from banks, so when those banks’ mortgage departments got into trouble, lots of them sold their paper contracts in the commodities markets to cover losses elsewhere.

Q And what’s the answer?
A If I’m pushed, probably somewhere around $65 a barrel. But no-one can put a figure on it, really. The best thing would just be a stable oil price that allowed consumers and producers to plan ahead.
World oil reserves, 2008
Source: BP Statistical Review of World Energy 2009

Legend
Oil reserves
(Thousand million barrels)

- 200+
- 100 to 199
- 50 to 99
- 25 to 49
- 0.5 to 24
- negligible

Notes: Proved reserves of conventional oil -
Generally taken to be those quantities that geological
and engineering information indicates with reasonable
certainty can be recovered in the future from known
deposits under existing economic and operating
conditions.
### Top 10 producers, 2008

<table>
<thead>
<tr>
<th>Country</th>
<th>Thousand barrels a day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Saudi Arabia</td>
<td>10,846</td>
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<tr>
<td>Russian Federation</td>
<td>9,886</td>
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<tr>
<td>US</td>
<td>6,736</td>
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<td>Iran</td>
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<td>Canada</td>
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<td>Venezuela</td>
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### Top 10 consumers, 2008

<table>
<thead>
<tr>
<th>Country</th>
<th>Thousand barrels a day</th>
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<tbody>
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<td>US</td>
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<td>India</td>
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<td>Saudi Arabia</td>
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Natural gas prices and the link to oil

Q Everyone talks about oil prices — but what about natural gas? Isn’t that important?

A It sure is. Our economy depends on oil. But for a variety of reasons — economic as well as environmental — developed countries, especially in Europe, have been shifting to natural gas as their preferred fuel for generating electricity. So when the price of natural gas rises, so does the power bill. For some households and many businesses, that’s one of the biggest single drains on their budget.

Q But are oil and gas prices connected? They’re both hydrocarbons…

A Yes and no.

When oil prices rise, natural gas prices tend to follow. For one thing, when oil prices rise, the cost of producing oil also rises. And because a lot of our natural gas comes from the same place — as “associated gas” that sits next to the oil in a field — the cost of producing the gas rises, too.

Furthermore, in many parts of the world, historical reasons mean that natural gas supply contracts are negotiated based on the oil price. So, for example, in Europe, the continent’s largest gas supplier, Russia’s Gazprom, was charging customers about $450 per 1,000 cubic metres of gas last year. In mid-2009, new deals were being struck at just over $200.

Then there’s liquefied natural gas (LNG). Like the gas Gazprom sells through its pipelines to European customers, LNG is also usually traded under long-term contracts — for, say, supply over 20-25 years. These contracts are also based on the price of oil. LNG prices have also been falling lately.

Q That’s the “yes” part answered. What about the “no”?

A The gas sector is segmented along regional lines in a way the global oil market isn’t. So in the US, the world’s biggest gas market, the discovery of vast new domestic supplies (see p55) is putting pressure on local gas prices. It happened at the same time as the oil price fell last year, but for a different reason.

Then there’s the LNG spot market. About 15% of LNG supply is not contracted through long-term arrangements, but gets traded cargo-by-cargo, according to the dynamics of supply and demand. When South Korea and Japan, the two biggest LNG users in the world, need more LNG, their buying can push up prices. However, they’ve also been hit by the global economic recession and demand for gas in both countries is way down.

LNG will probably stay cheap for a while, too, because countries such as Australia, Nigeria and Qatar have been developing new LNG-export projects. Soon, there could be a glut of LNG on the world market, especially as the US no longer looks like the big market for LNG that many expected it to be.

Q So if prices for piped gas get too expensive, everyone can just import LNG instead?

A Only if they build special terminals to receive the stuff. In fact, the natural gas business could really be called an infrastructure business. Pipelines, terminals, liquefaction plants — there’s the essence.

There’s no shortage of gas on the horizon, but once consumption starts to rise quickly again it’s the countries that built the necessary infrastructure that will have a steady stream of affordable gas.
Let’s rock: Groningen field hits 50

1959 Discovery of the Groningen field — Europe’s largest gas field. Initial reserves estimates are for 60 billion cubic metres of gas. Over time, that figure is revised up to 2.8 trillion cubic metres

1963 First gas delivered from Groningen field to the Dutch market. The Netherlands becomes a natural gas country

1976 Peak production reached. Groningen produces 84 billion cubic metres of natural gas over the year

1997 Agreement signed for €2 billion modernisation of Groningen’s production system to combat steadily declining pressure. The programme, involving the installation of compressors in 296 wells to suck the gas to the surface, is completed in 2009

2009 The Groningen field reaches its 50th anniversary, with output in 2008 amounting to 41 billion cubic metres. Around 60% of the field’s gas reserves have now been produced, resulting in a 50% drop in reservoir pressure. But the operator, the Netherlands’ Nam, expects the field to continue to produce for another 50 years

1959 Fidel Castro sworn in as Cuba's leader. Hovercraft launched

1963 Rolling Stones start their recording career, having formed the previous year.

1976 Steve Jobs and Steve Wozniak form Apple Computer Company

1997 Cloning of the first mammal — Dolly the sheep

2009 Mick Jagger, 66, still in business. Can he keep going for another 50 years?
World natural gas reserves, 2008
Source: BP Statistical Review of World Energy 2009

Legend
Gas reserves (Trillion cubic metres)

- 30.00+
- 20.00 to 29.99
- 3.00 to 19.99
- 1.00 to 2.99
- 0.01 to 0.99
- negligible

Notes: Proved reserves of conventional gas - Generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known deposits under existing economic and operating conditions.
3.2 — Supply and markets

### Top 10 producers, 2008

<table>
<thead>
<tr>
<th>Country</th>
<th>billion cubic metres</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Russian Federation</td>
<td>601.7</td>
</tr>
<tr>
<td>2 US</td>
<td>582.2</td>
</tr>
<tr>
<td>3 Canada</td>
<td>175.2</td>
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<tr>
<td>4 Iran</td>
<td>116.3</td>
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<tr>
<td>5 Norway</td>
<td>99.2</td>
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<tr>
<td>6 Algeria</td>
<td>86.5</td>
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<tr>
<td>7 Saudi Arabia</td>
<td>78.1</td>
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<tr>
<td>8 Qatar</td>
<td>76.6</td>
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<tr>
<td>9 China</td>
<td>76.1</td>
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<tr>
<td>10 Indonesia</td>
<td>69.7</td>
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</tbody>
</table>

### Top 10 consumers, 2008

<table>
<thead>
<tr>
<th>Country</th>
<th>billion cubic metres</th>
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</thead>
<tbody>
<tr>
<td>1 US</td>
<td>657.2</td>
</tr>
<tr>
<td>2 Russian Federation</td>
<td>420.2</td>
</tr>
<tr>
<td>3 Iran</td>
<td>117.6</td>
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<tr>
<td>4 Canada</td>
<td>100.0</td>
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<tr>
<td>5 United Kingdom</td>
<td>93.9</td>
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<td>6 Japan</td>
<td>93.7</td>
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<td>7 Germany</td>
<td>82.0</td>
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<tr>
<td>8 China</td>
<td>80.7</td>
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<tr>
<td>9 Saudi Arabia</td>
<td>78.1</td>
</tr>
<tr>
<td>10 Italy</td>
<td>77.7</td>
</tr>
</tbody>
</table>
Peak oil: not yet

There’s plenty geologists still don’t know about oil and how it was formed, but they tend to agree on one thing. Oil is finite. If we keep sucking it out of the ground, one day it will run out. And, boy, are we ever hungry for oil. Last year, the world used about 84.5 million barrels a day of it. That’s 150,000 litres a second.

Last year, while oil prices soared, something else started flowing: a seemingly endless stream of claims that the world had reached “peak oil”.

Oil can’t last forever

As a concept, the peak-oil claim has that kernel of truth — the oil can’t last forever. But in reality, the term masks a host of other claims. The most alarming is that because we are so reliant on oil, and because we haven’t yet found something to replace it, the peak will bring economic depression, wars, famine and other features of apocalypse. In that context, it’s a belief that has much in common with other Malthusian worries, such as the fear that the world’s population is growing too quickly for food production to keep up.

There are more refined versions of peak-oil theory. The most convincing argues that while we might not have used over half of our oil and, therefore, reached a “geological peak”, we will never be able to extract much more than we do now. At the same time, natural depletion means we need each year to replace about 6% of our oil reserves just to stand still. It’s not just cranks who hold these claims: the boss of France’s Total doubts that global oil output will ever reach 100 million barrels a day. That’s more than enough for now, but might not be enough in the future.

That’s a far more plausible — and equally worrying — prediction. In recent years, politics and economics have hindered many companies’ access to countries where oil is known to be plentiful.

But those two forces aren’t immovable in the way geology can be. And yet, geologically, we’re a long way from the end of oil. Including unconventional oil, such as the reserves in Canada’s oil sands, we have 3.7 trillion barrels left, says Cambridge Energy Research Associates, a consultancy. And that figure is likely to grow as recovery techniques improve. At present, only about 35% of the oil in an oilfield is recoverable; but improving that ratio to 50% would add 1.2 trillion barrels to reserves — more than has been produced so far.

Peak oilers dispute those numbers and say producers distort the facts. Maybe. But peak oil has a patchy record of its own. The “peak” has been repeatedly — and wrongly — predicted, and it hasn’t happened yet.

It doesn’t pay to mock the predictions of the end, though, because unless things change, one day they’ll come true. To prevent the apocalypse, the energy industry needs to keep finding new reserves, improve the recovery rate from existing ones and develop alternatives. Consumers, meanwhile, should be thankful for what they’ve got, use it sparingly and embrace new technologies. With some luck, we’ll never run out of oil — because we’ll never need to exhaust it.

Including unconventional oil, such as the reserves in Canada’s oil sands, we have 3.7 trillion barrels left
The ultimate guide to energy
... coming to the web in January 2010

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OPEC, the IEA and prices

Crude oil is the world’s most actively traded commodity. Much of the money changes hands in the busy futures markets of London, New York and Singapore. And the oil price is not just relevant to oil: it dictates the cost of other forms of energy, including natural gas, and the cost of producing many other materials, such as steel.

Oil prices are referenced against benchmark crudes (see box), trading at a premium or a discount to them, depending on their quality: those that yield a greater volume of high-value products — such as gasoline — are more expensive than those that produce greater quantities of lower-value products, such as fuel oil. Brent is used to price around two-thirds of the world’s internationally traded crude oil — even though produced volumes of North Sea Brent crude are now very small. The Organization of the Petroleum Exporting Countries (OPEC) — a group of producing countries that includes many of the world’s biggest oil-supplying nations — also has its own reference price, the OPEC basket.

What is OPEC?

OPEC is a prime force in influencing global oil prices: when it cuts output, there is less oil available to the world and prices generally rise; when it boosts supply, prices generally fall. OPEC, headquartered in Vienna and now made up of 12 member countries, was formed in 1960 by Saudi Arabia, Iran, Iraq, Kuwait and Venezuela, which remain members. The other seven, joining the group at various stages, are: Qatar, Libya, the UAE, Nigeria, Algeria, Ecuador and Angola.

It wasn’t until the early 1970s that OPEC became a global powerhouse. Until then, the oil market was dominated by seven large firms, known as the Seven Sisters, which produced more than 90% of Middle East oil. But the outbreak of war between Israel and the Arab states in 1973 resulted in a big shift in the balance of power. OPEC’s Arab members halted oil supplies to countries supporting Israel — the US and western Europe. Oil prices quadrupled. Since then, the group has generally been able to act as a swing producer, varying output according to the market’s need for oil or its own view of where prices should be — largely thanks to the extremely large capacity of one country, Saudi Arabia, which alone is theoretically capable of supplying around 12% of world oil demand. Only where global growth has slowed rapidly, such as between 1998 and 2001, has the OPEC proved unsuccessful in manipulating oil prices.

The consumer response

OPEC’s view of what prices should be usually clashes with the view of the International Energy Agency (IEA), set up in 1974 by developed consumer countries in response to the oil crisis. Its purpose was to co-ordinate the consumer response to oil-supply emergencies and to counter OPEC’s growing power. The IEA’s most important act was to tell member countries to store three months’ worth of oil, in case of a supply stoppage.

The IEA still tries to influence the geopolitics of oil to the advantage of its members — countries in the Organisation for Economic Co-operation and Development — by, for example, urging producers to sell more oil or invest more in developing their reserves to ensure steady flows of oil in the future. And it often disagrees with OPEC: where OPEC generally wants to get more for its oil, the IEA generally wants energy to be more affordable.

### Benchmark crudes

The main benchmark crude oils are: Brent, a combination of crude oil from 15 North Sea fields, with an associated futures contract traded at London’s ICE Futures exchange; and West Texas Intermediate (WTI), produced in the US, with an associated futures contract trading on the New York Mercantile Exchange. In the Mideast Gulf, Dubai crude is used as a benchmark to price sales of other regional crudes to Asia.
Who gets what from a litre of oil?

Newspapers often blame oil producers if the price of gasoline is perceived to be too high. But a large component of the final cost of pump products is taxation levied by the government of the country where the oil is being consumed. This is the principal reason why gasoline prices vary substantially from country to country.

According to the Organization of the Petroleum Exporting Countries (OPEC), the amount of money the UK government receives from taxing oil products is around 1.6 times the amount OPEC members get from the sale of their crude oil.

Between 2003 and 2007, says OPEC, the G7 nations (Canada, France, Germany, Italy, Japan, the UK and the US) made $2,585 billion from oil taxation — slightly more than the $2,539 billion OPEC generated from oil sales in the same period. But, argues OPEC, the producers’ net take is substantially lower than that of the consuming economies: whereas the G7’s tax revenue is “pure profit”, the producers had to meet the cost of finding, producing and transporting their oil from their $2,539 billion.

The true cost of gasoline

$ a litre

Source — Opec (based on 2007 data). *fob = free on board
Copenhagen: what to expect

What will 2009 have brought us? When historians look back they might say it was the year when some of the giants of American industry went under. Or they might reflect on political events in Iran. Few of them will forget to mention President Barack Obama.

But they might also point to something that happened in December 2009. At least, that’s what anyone who wants to stop global warming will hope. Because that’s when the world’s governments will gather in Copenhagen to argue over — and, just possibly, agree on — a new treaty to fight the emissions that are heating up our planet.

There’s a lot at stake, because despite the rhetoric of recent years, emissions keep rising — by around 3% a year. And unless that trend is reversed, say climatologists, climate change could soon be unstoppable. The track record of these kinds of agreements isn’t good. Everyone’s familiar now with the Kyoto Protocol, an agreement signed in Japan in 1997 that laid the ground for the United Nations Framework Convention on Climate Change. At Kyoto, diplomats from almost 200 countries agreed to a series of limits on how much greenhouse gas their nations would be allowed to emit. Bizarrely, some countries, such as Australia, were allowed to increase emissions; others, such as those of the EU, committed to an 8% reduction against the amount they’d been emitting in 1990.

But Kyoto expires in 2012. A new agreement is necessary, and quickly, because turning treaties into practice soaks up time like nothing else. If they agree in Copenhagen, signatory-countries will go home and begin the process of ratifying the treaties. Many countries took years to ratify Kyoto; some, such as the US, didn’t even get that far.

In retrospect, the Kyoto agreement looks like a failure, leaving the world perilously close to the point of no return. David MacKay, an expert on measures to fight climate change at Cambridge University, UK, says that if serious reductions in our emissions aren’t made in the next two or three years the battle will switch to “adaptation” — coping with a hotter climate, not preventing it.

We’re in that predicament, critics of Kyoto say, because the protocol didn’t demand enough and countries didn’t deliver what they pledged. Schemes for reducing carbon pollution that Kyoto envisaged, such as emissions-trading markets, have hardly developed; and where they have, such as in the EU, their effectiveness has been watered down by special interests. So coming to an agreement in Copenhagen that actually does something is crucial.

Twelve years on from Kyoto, the worries about climate change are now widespread, thanks to campaigning by individuals such as former US vice-president Al Gore. Climatic events such as Europe’s blistering hot summer of 2003, which killed tens of thousands, and 2005’s devastating hurricanes in the US have also focused minds.
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Yet despite the media’s fascination with climate change, despite the campaigning by celebrities, despite the prevalence of green thinking, the global recession has taken steam out of the movement. Governments feel restoring economic growth is a more pressing priority, and green projects that could abate global warming look like pricey luxuries.

That lukewarm approach to the climate issue has been evident from the way the main parties who will be expected to agree terms in Copenhagen — the big economies such as the US, EU and China — have gone about preparations for the meeting. Normally, multigovernmental treaty meetings come after months of work by busy “sherpas”, the diplomats who specialise in horse-trading across conference tables. The idea is to have an agreement in place, so when senior officials jet in they just have to hammer out the last few fine details. This time around things have been low-key. Indeed, half way through 2009, Germany’s environment minister, Sigmar Gabriel, said the meeting could be a “disaster”. The preparatory meetings had failed to bring any “movement” towards Copenhagen.

Mega sticking point

There’s one mega sticking point. Who is responsible for emissions and who should pay to fix the problem? Take the case of China. Building a new coal-fired power station every week, China has been the bugbear of environmentalists in the West. The country has now overtaken the US as the world’s biggest carbon emitter. If we can’t stop China’s emissions, what’s the point of doing anything ourselves? Why should we take a financial hit and let China off? That, in a nutshell, was one argument opponents of Kyoto in the US used to derail their ratification of the treaty.

But hang on. China has prioritised economic growth over the environment, true. But when you break down its emissions in per capita terms — how much each Chinese person emits — the figure is just a fraction of the average per capita emissions in the West. Furthermore, Westerners have had 200 years abusing the environment to get rich. If we hadn’t pumped all that carbon into the atmosphere in the first place the world wouldn’t be at the tipping point.

There are counter arguments to this. The West also grew rich through slavery — and no one thinks the developing world should follow that course. But the dispute is, nonetheless, almost intractable. If Copenhagen manages some kind of compromise, it will be a triumph over deep-seated biases.

But there is hope, and it comes in the form of the US’ new president. Obama has promised to revolutionise the country’s stance on climate change It’s probably one reason he was surprisingly awarded the Noble Peace Prize in 2009. Where the George W Bush administration objected to Kyoto, Obama promises leadership in Copenhagen.

He’s also a self-proclaimed multi-lateralist. Many other leaders, under pressure at home, want to bask in his international popularity. And several Kyoto laggards, such as Canada, are well within the orbit of US influence. Western governments have also been chastened, not to say humbled, by their recent economic failures. All of these factors might make for more listening — and less arguing — by the developed and developing world.

China, for one, is now promising action. In September 2009, president Hu Jintao promised China would reduce its emissions by a “notable margin” in the next decade.

So, be hopeful for an agreement in Copenhagen that makes 2009 the year the world fought back. But don’t expect miracles. Compromise is the name of the game in international treaty-making, especially when the stakes are as high as they will be in December. Don’t be surprised if the diplomats fudge in Denmark and bigger decisions are postponed until 2010. We might have to wait while bluffs are called and horses traded. It could take months and probably will. But will the climate wait for us?
Cutting emissions: the big challenge

Fossil fuels are going to provide a significant part of our energy needs for decades to come. We need to use green energy, but replacing oil, gas and coal overnight with renewable or nuclear power would be both impractical and very expensive. That means energy companies need to make their industry as sustainable as possible by exploring all avenues to cut carbon dioxide (CO₂) emissions.

Their expertise has been important in formulating a global response to climate change at forums such as the UN-sponsored conference, held in Copenhagen in December 2009. Some of the industry’s views are channelled through the International Petroleum Industry Environmental Conservation Association (IPIECA), a body with observer status at UN talks, which provides a conduit for the latest initiatives coming from its members in the oil and gas industry.

“The oil and gas industry realises major challenges and opportunities lie ahead in addressing climate-change risks. These include taking actions now to reduce emissions, providing new, more powerful energy options and gaining a clearer understanding to better guide society’s response,” IPIECA says.

But what does this mean in practice?

To stem carbon emissions, companies can reduce the emissions they produce in the first place; stop the CO₂ and other greenhouse-gases (GHGs) they do produce from entering the atmosphere; or help reduce emissions from other sources. Oil and gas firms are active in all these areas.

Going underground

The technology that has perhaps generated the most headlines in the fight against global warming is carbon capture and storage (CCS), which enables CO₂ to be captured at source — at an oil and gas processing facility or power station for example — and then buried out of harm’s way in depleted oil and gas reservoirs, or other underground chambers, such as aquifers. This is an enticing prospect, because if that can be made to work, then fossil fuel will be a lot less damaging to the atmosphere over the remainder of this century (see p94).

Although it is a costly technology, which has yet to be adopted on a widespread basis, the signs from pioneering projects around the world are encouraging. Proponents say there is no reason the technology cannot be scaled up for wider use.

The coal industry is being targeted initially for CCS use, because coal burning results in more carbon emissions than the combustion of oil or gas. But oil and gas companies are not sitting on their hands, as they know their industry also needs to act.

Some of the pioneering work was led by the IEA Greenhouse Gas Programme in the early 1990s. Within this programme the first carbon-storage monitoring exercise was set up in the North Sea with Norway’s StatoilHydro and its partners. StatoilHydro has managed to keep the CO₂ content of
the gas produced from its Sleipner West gas field to below the 2.5% level needed to meet local environmental requirements. The CO$_2$ is removed by passing the gas through solutions of chemicals commonly known as amines — a process also used in oil refineries and petrochemicals plants — and is then buried in an aquifer over 800 metres below the seabed. By the end of 2008, the project, which started in 1996, had stored almost 11 million tonnes of CO$_2$, which has been carefully monitored so that the industry has a better understanding of how the gas spreads underground when new projects are developed.

Oil companies are even helping the coal industry to cut CO$_2$ emissions. Synthetic gas, or syngas, can be created from the heavy residues created in oil refining, which can then be used to produce power, or in other industrial processes. But this can also be done with coal in a way that makes the business of stripping CO$_2$ out of the power plant easier and cheaper than it would be if the coal were burned directly.

While coal gasification adds around 10% to the cost of coal-fired power stations initially, it comes into its own when CCS is applied, as it is much easier and cheaper to strip CO$_2$ from syngas than from power-plant flue gases. According to Shell, a pioneer in gasification, that could make syngas nearly 10% cheaper than coal, if CCS is used in both cases. Shell is working to make the technology more attractive in places such as China, where coal is fuelling much of the country’s rapid economic growth.

Flares go out of fashion
Less high-profile than CCS, but equally important in emissions cutting are efforts to reduce the use of flaring at oil and gas fields — the practice of burning unwanted gas. When the world was a less environmentally aware place, flaring or venting seemed a convenient way to get rid of an unwanted by-product. Now it looks like a waste of a valuable commodity and a way of pumping methane — a dangerous GHG — directly into the atmosphere.

The industry is now coming up with solutions to this problem. For example, when Marathon Oil became operator of the Alba field off the coast of Equatorial Guinea in west Africa in 2002, the focus of production
The world’s population has doubled in the past 50 years to 6.7 billion and it’s expected to reach 9 billion or more by 2050 — a lot more people wanting heat, light and mobility.

That’s not all: in China and India alone, more than 500 million people will move from a rural to an urban way of life in the next two decades. The world has no experience of industrialisation on this scale. When Europe industrialised, it involved 50-100 million people moving from a rural to an urban way of life. It was 150-200 million people in the case of the US. And in Europe and the US, the changes took place over several decades.
was on gas condensates, so-called wet gas, while natural gas, or dry gas, was flared off. The US company overhauled the project, installing processing facilities, compressors and the pipelines required to send gas that previously would have been flared back offshore for reinjection into the reservoir. The process cut flared gas volumes by more than 90% after it became fully operational in 2005. It also helped maximise the amount of gas available for Marathon’s Equatorial Guinea liquefied natural gas project, the first stage of which was completed in 2007.

The by-products of hydrocarbons processing are also being used through the development of cogeneration facilities linked to refineries and petrochemicals plants. Cogeneration entails producing power and heat simultaneously. The excess heat captured from refining or power-generation processes can be used as a substitute for carbon-intensive activities, by converting it into steam for use by industry or by using it directly to heat nearby houses or business premises.

ExxonMobil has taken a lead in this area, building more than 1.5 gigawatts of cogeneration capacity in five countries between 2004 and 2009. One of the latest of its cogeneration plants came on stream at its refinery in Antwerp, Belgium, in early 2009. By supplying heat and steam for industrial processes, in addition to generating 125 megawatts of power, the plant will reduce Belgium’s carbon emissions by around 200,000 tonnes a year, or the equivalent of taking 90,000 cars off the road, the company says.

**Going green**

And then, of course, there is direct investment in renewable energy. Many of the big oil companies have diversified their businesses to include renewables. Players such as BP have substantial interests in the solar and wind industries, while most oil companies have invested heavily in biofuels, which can replace or be mixed with gasoline to reduce carbon emissions from transport.

Those investments have, in part, been motivated by government regulations requiring biofuels to occupy a minimum share of the fuel mix. Yet despite their environmental promise, biofuels have proved controversial: doubts have been raised about their environmental and economic sustainability. When the energy required to cultivate, harvest and transport the crops, and then process them into fuels, is taken into account, there might not always be a carbon saving compared with fossil fuels. Also, because the crops often occupy land that might otherwise be used for food crops, there is a risk that cultivating crops to make biofuels could lead to food shortages and food-price inflation.

Technology — being developed mainly by energy companies — could provide the answer. The industry is researching the development of biofuels that could theoretically be carbon neutral, cultivated from land unsuitable for food crops and from inedible parts of plants (see p78 and p114). Success could revolutionise the transport industry.

The climate challenge is one to be taken up by all industries and individuals around the world. But expect to see the oil and gas industry playing a lynchpin role.

ExxonMobil’s cogeneration plant at its Antwerp refinery will reduce Belgium’s carbon emissions by the equivalent of taking 90,000 cars off the road.
Water — a precious resource

Reducing carbon emissions will help to stem rising global temperatures, but that may not be the most immediate major environmental challenge the world faces. A growing global population, increasing per capita consumption and the effects of climate change are combining to put a huge strain on the world’s water resources.

This is of more than just a passing concern for the hydrocarbons industry, as oil companies use more water than oil in their operations and they operate in some of the driest regions of the world, such as the Middle East. Fresh water is a vital component across the supply chain, from production and manufacturing to steam and power supply, while seawater is used in cooling systems and to stabilise pressure in oil reservoirs.

This means oil firms shoulder a lot of responsibility for ensuring scarce water resources are not wasted, over-exploited, and that marine environments are not damaged. Through IPIECA, the global oil and gas industry association for environmental and social issues, the major oil and gas companies have developed a series of good-practice guidelines based on operating responsibly and building capacity.

“The oil industry sees itself as having a dual role in water-resource management: to reduce the impact of our operations and to contribute to the communities where we operate,” IPIECA says.

The oil industry has a dual role in water-resource management: to reduce the impact of operations and to contribute to the communities where it operates

This means implementing measures to manage water use carefully to meet not just the needs of the oil business, but also the surrounding environment and the community. It also means firms need to invest time, effort and money in new ways of making water use more efficient and to improve...
access to fresh water and sanitation for those living near their facilities.

Recycling is an obvious way oil firms can help to conserve water. Where possible, reclaimed wastewater or low-grade natural water is used in industrial processes. That means more fresh water is available for the local community and for agriculture. Water used in oil-related facilities can also be recycled, for use as irrigation water, for example.

Meanwhile, oil companies are committed to ensuring water discharged from their facilities is properly monitored and treated, and that it is carefully stored to avoid wastage or contamination.

Giant strides

The results of this approach are visible in the way all the big oil companies work today. The exploration and production division of France’s Total, for example, implemented a plan to reduce the oil and gas content of discharged water by 66% in 2002. Most of its operations had reduced the level to 30 parts per million (ppm) in 2008. The division has a target of 10 ppm for water discharged onshore in 2010.

Four of the eight refineries operated by Chevron worldwide have technology installed that enables them to use treated effluent from the local area to help meet their water needs. Chevron says around a quarter of total water usage at its refineries is now supplied by reclaimed wastewater, adding up to some 45,000 cubic meters a day of municipal effluent. More measures are on the way.

The US’ supermajor also faces a difficult and unique water-conservation challenge off the coast of Western Australia, where it is developing the Gorgon liquefied natural gas (LNG) processing and export facility — one of the world’s biggest — on Barrow Island. This is a highly fragile landscape, which is home to rare animals and has barely enough water to cater for its own ecosystem, let alone an LNG plant likely to need 1,500 to 2,000 cubic metres of water a day.

In order to press ahead with the project, Chevron and its partners have had to draw up a meticulous environmental plan and ensure that the plant will not compromise the island’s scarce fresh water supplies. This is to be achieved by installing: a reverse osmosis system, to desalinate seawater into fresh water; and recycling facilities and by taking measures to minimise water use overall.

Of course, more can always be done to improve the industry’s use of water resources. Nowhere is research more important than in the Middle East, where big oil and gas deposits exist in an environment of scarce water supplies. In Qatar, which has huge hydrocarbons reserves, ConocoPhillips’ Global Water Sustainability Centre opened in 2009. This provides a base to investigate new methods of treating and reusing by-product water from oil production and refining operations, and further develop industrial and municipal water sustainability.
Biggest games console in the world

Seismic and other geophysical imaging techniques are the only way of assessing what the reservoir might contain without drilling into it. As such they are an invaluable part of the exploration and production process.

Seismic imaging has done for oil what medical imaging has done for the health industry. Twenty years ago, doctors had to rely on exploratory surgery as a diagnostic tool. Now, scans often make risky physical intervention unnecessary. It’s the same in oil; without seismic, explorers would have to perform a great deal of expensive exploratory surgery in the form of dry or non-optimal wells in order to strike it lucky.

Picture of the subsurface

Seismic is an imaging technique that allows geophysicists to form a detailed picture of what the layers of rock are like — and, therefore, to choose the optimal location for a well. It works by causing explosions or mechanical vibrations on the earth’s surface — usually generated by a vibrating pad under a truck, on land, or by specially equipped boats.

Sound waves go into the ground and are reflected off layer after layer of subterranean rock. Microphones on the surface measure the rebounding signal. Computers then analyse the data to build a sophisticated picture of the subsurface. The images allow exploration companies accurately and cost-effectively to evaluate a promising target for its oil and gas yielding potential, explains CGGVeritas, which provides data processing and imaging services to the oil industry.

It’s like bouncing a ball: the quality of the surface dictates the quality of the bounce. Only, of course, it’s more complicated than bouncing a ball.

Obtaining a clear signal in the first place is extremely difficult. Background noise severely degrades the quality of the signal.

Seismic is an exciting field embracing geology, physics, mathematics, electrical engineering and computer technologies. It is a thoroughly satisfactory career — Roberto Fainstein, Schlumberger geophysicist

Computers analyse the data to build a sophisticated picture of the subsurface
5.1 — Technology: pushing boundaries

Offshore, seismic benefits from the fact that sound travels well through water. But some onshore environments, such as the deserts of the oil-rich Middle East, are problematic. The sand deadens the signal before it has gone very far under the ground. And the undulation of a desert dune means microphones laid out on the surface to capture the rebounding signal won’t all be at the same height — a snag when millisecond timing is involved.

The offshore environment has its own challenges: special vessels have had to be designed to be capable of towing several lines of microphones — called streamers. A modern 3-D seismic vessel might tow as many as 20 eight-kilometre-long streamers, with the outer two as much as a kilometre apart — not a job for any old ship. “Keeping this technology up to date requires dedicated teams of engineers that are always working on the very edge of technology,” says Walker.

Focusing seismic images presents further difficulties: whereas a modern camera on autofocus mode fixes on a single point in the distance, geophysicists must analyse an image with infinite depth of focus — everything from drilling risks on the seabed to the deep structure beneath the reservoir. That task can be made even more onerous when, for example, there is a large salt layer below the seabed to penetrate. This refracts the signal, like light through a prism. One geophysicist likens it to “looking through a shattered window pane”.

Mammoth computing power

And modern seismic surveys — known as three-dimensional (3-D) seismic — generate terabytes of data, which calls for huge computing power. It’s no surprise that the first use of a Cray supercomputer was in the seismic industry and the seismic industry is the single biggest user of computer power today.

Seismic imaging: It’s like bouncing a ball, but much more complicated
Name: Arsen Shnashev  
Company: Schlumberger  
Present job: Maintenance manager for drilling and measurement operations  
Age: 29  
Nationality: Kazakhstani  
Degree: Bachelors in Industrial Engineering, Middle East Technical University, Ankara, Turkey

While I was at university I did internships in the construction and tobacco industries, before taking a placement at a company that built oil and gas production facilities. Energy caught my imagination: it meant working internationally, being exposed to different cultures and languages, always having something new to learn and working with and developing new and exciting technologies.

After graduating in 2002, I joined an oil company in Kazakhstan, working as a mechanical-reliability engineer at a gas-processing plant that stripped out hydrogen sulphide from gas produced at one of the country’s biggest oil projects. A year later, I joined Schlumberger and immediately experienced the benefits of its international reach. I was assigned to Nigeria, working as a measurements engineer in offshore projects. I worked with logging and measurements-while-drilling tools. These are sophisticated electronic devices that evaluate the physical properties of a well — such as resistivity and porosity — and take pressure, temperature and wellbore trajectory readings, all while the drilling is taking place. The data are transmitted to the surface in real time.

After three years in the field, I moved to an office in Port Harcourt, Nigeria, working as an onshore-support engineer. That involves sitting in a state-of-the-art communications centre, monitoring data that are being beamed in from various wells across the region and sharing the expertise I’d acquired as a field engineer with more junior staff.

From there I moved to the technical side of the maintenance department. Downhole tools are put through extremely testing conditions — very high temperatures and pressures, for example. Reliability is a priority, making maintenance a core part of our activity — as vital as developing new technologies.

After a stint in Schlumberger’s maintenance centre in Aberdeen, I moved to Turkmenistan, Central Asia. We receive tools that have been used in the field, upgrading, repairing or maintaining them as necessary. It’s a challenging job: you have to be up-to-date with the latest technology and with the many different product-quality standards in force across the world. Our tools must comply with all of them. And the task will get tougher because the downhole conditions that oil companies are facing are generally becoming more onerous.

An important part of the managerial side of my job is examining the processes we use and applying lean manufacturing principles to make the workshop more efficient — and to provide the best service quality by ensuring our equipment is reliable.

There’s an important communications element to the job too: I work closely with Schlumberger’s engineering and product centres across the world, because we work globally and any changes in engineering practices must be implemented everywhere.

There’s never a dull moment: there’s a different problem to tackle every day. But there’s great support from other parts of the company and a lot of experience and knowledge to draw on. To do this job, you need energy and stamina: but if you want to see the world and work with latest technologies in the oil industry it’s a good place to be.
Interpretation, the final step, is a science and an art. A seismic picture is actually of interfaces — between, for example, two layers of rock or between the seabed and the water. Differences in interfaces cause a reflection in the way light reflects off a surface; seismic, therefore, provides information about the difference between rock layers, but no information about the rocks between. “It’s like getting a bank statement that says you have $400 more than last week, but doesn’t tell you how much you have in total — it’s all very relative,” says Walker. Geophysicists take the data and try to assemble a picture of the likely physical characteristics of rocks and fluids that could have produced the seismic record they are analysing.

Geophysics enters a new dimension

Time-lapse 3-D seismic (sometimes called 4-D seismic) could lead to a significant rise in the world’s recoverable reserves; today, much less than half of the oil in a typical oil field is produced. The technique is utilised to monitor the production and depletion of an oil field over time and involves running more than one 3-D survey on the same spot, but with an interval of a year or more. Data comparisons — made by subtracting one data set from the other — can show areas of the field that have been depleted over time and highlight areas where in-fill drilling would be useful to tap pockets of bypassed oil.

Typically 30-40% of the oil in a field is produced and 60-70% is left in the ground. However, an estimate by analysts at Cambridge Energy Research Associates suggests 4-D seismic could result in a leap in overall recovery factors of 8% worldwide. That implies producible reserves could rise by a colossal 20%.

In addition to 3-D surveys, much less data-intense two-dimensional surveys continue to be shot, especially in highly speculative areas in order to assess whether it is worth stumpng up the investment needed for a 3-D survey.

It may soon be possible to see through hitherto impenetrable substances, such as basalt, a volcanic rock

This is where computers have made such a big difference. Says Walker: “When I started in this industry about 25 years ago, we used to print off 2-D data [a less data-intense form of seismic] on paper and interpreters had coloured crayons and spent their day drawing on the various interfaces and trying to work out what the geology was.” Now computers can manipulate 3-D images in seconds, enabling geophysicists to visualise the reservoir. “It’s like being paid to play with some of the biggest games consoles in the world.”

Improvements in recent years in the quality of seismic imaging have been so spectacular that it may soon be possible to see through hitherto impenetrable substances, such as basalt, a volcanic rock.

Other imaging techniques are emerging to complement seismic. These include electromagnetics. Specially generated electrical currents can help identify specific rocks and fluids by measuring the resistivity characteristics of subsurface rocks.

Alternatively, geophysicists can take advantage of the steady stream of electromagnetic radiation from the sun that propagates into the earth.

The changing of the tides

Explorers are also starting to make use of natural seismic noise from inside the earth to see the distribution of oil and gas and how they move. And reservoir engineers monitor the pressures of oil and gas and water, which regularly change minutely with the rise and fall of the tide and onshore with the rise and fall of the moon — another source of guidance for the future.
Offshore marvels

Designing and building offshore platforms are among the greatest engineering challenges in the oil and gas industry — or any sector.

Compare the aeroplane piloted by Orville Wright in 1903 — in the first controlled, powered flight — with a Boeing 747. The 747 entered commercial service just 67 years after Wright’s historic achievement, but the differences between his aircraft and a modern airliner are simply staggering.

Or compare the 1946 Electronic Numerical Integrator And Computer, the first general-purpose electronic computer, with the latest laptop. And what would Alexander Bell have made of an iPhone?

The same breathtaking rate of development has been achieved in the offshore oil industry. It began more than a century ago when a well was drilled at the end of a pier stretching about 100 metres into the Pacific Ocean, off the Californian coast. The earliest offshore platforms consisted of wooden derricks mounted on barges that could operate in a metre or two of water.

By the mid-20th century, these rudimentary systems had been replaced by platforms supported by tubular steel members that extended to the seafloor. In 1947, Kerr-McGee spudded the first well from a fixed platform beyond the sight of land, a technological breakthrough that marked the beginning of the modern offshore industry.

Fast forward to 1995 and the launch of Norway’s Troll gas platform, a 0.656 million tonne concrete structure. At 472 metres, it’s the tallest installation ever moved by humans — and 30 metres taller than the Empire State building.

It’s not just the scale of modern oil and gas platforms that’s impressive, it’s what they can do. BP’s Thunder Horse facility in the Gulf of Mexico, the world’s largest deep-water producing platform, pumps out about 260,000 barrels of oil a day — more than Colombia consumes. The largest floating, production, storage and off-loading vessel, the Kizomba A platform, offshore Angola, can store up to 2.2 million barrels — roughly equivalent to Iraq’s daily oil production (in mid-2009).

Daunting burden

And the physical burden platforms must deal with are daunting. Consider the 1.2 million tonne Hibernia platform: its gigantic concrete base is designed to resist the impact of drifting icebergs off the Newfoundland coast. In 2003, US oil major Chevron drilled a well in 3,051 metres of water in the Gulf of Mexico. The depth of that well, a record, is around six times the height of the world’s tallest building — Taipei 101.

Petrobras, a Brazilian oil company, has just started producing oil from a well at an oil field called Tupi that involves drilling down through 2,000 metres of water and a further
5,000 metres below the seabed — on the way passing through a layer of salt that, in places, reaches 2,000 metres in thickness. And all of this is happening 250 kilometres away from the comforts and amenities of Rio de Janeiro’s shoreline.

Offshore oil isn’t just hard to detect and get at; it’s often hard to get out of the ground. Perhaps it won’t flow on its own; temperatures at the bottom of the ocean may be too low or the oil itself may be too viscous — or both. The producer might need to heat up the oil in specially warmed pipes on the seabed until it’s runny enough to flow. Another solution might be to lower giant electrical pumps down through the water to give the oil a boost. You don’t need to have tried to make toast in the bath to appreciate the problems involved in designing and maintaining one of those for use under 2,000 metres of water.

Then there’s the water pressure to think about: how do you prevent the underwater equipment — the tubes that carry the oil and gas to the surface, for example — from being crushed under the weight of 2 kilometres of water. And what about strong tides and currents, high winds and waves, snow and ice, and earthquakes or other unstable conditions on the seabed? Sometimes the oil will be at high pressures and high temperatures. Sometimes it will be highly acidic and corrosive. All those considerations need to be taken into account when designing the equipment needed on the topsides — the facilities that sit on a platform’s deck.

It’s quite a list.

An enormous task

Not surprisingly, moving an offshore platform from concept to commissioning is an enormous task, which can take from one year to several years, depending on its size and type (see box).

Platforms need to be self-sufficient: they need their own power and communications equipment, accommodation facilities for workers, who spend weeks offshore at a time, docking facilities for crew and supply boats, a helipad, and cranes for lifting equipment and supplies onto the deck. In some cases, they must have the capacity to store huge volumes of oil until it can be transported to shore. They need to meet stringent environmental and safety standards and run for years with minimal maintenance. And they must be able to produce and process vast volumes of hydrocarbons.

The Independence Hub facility in the deep-water Gulf of Mexico, for example, produces...
In 1947 we designed and installed the first steel template offshore platform in the Gulf of Mexico.

Today we have 15,000 employees worldwide and operations in 14 countries.

We offer you the chance to be involved on projects from concept to commissioning.

Are you ready for the challenge?

We offer stable career growth potential, excellent benefits, challenging projects, and a world class team environment.
as much as 28 million cubic metres of natural gas a day from 16 wells — roughly equivalent to the consumption of South Korea.

The first stage in scoping out the optimal design for a platform is to estimate the field’s size, what mix of oil, gas and water it will yield, and how many wells should be drilled. Will it be used just for producing and storing oil or drilling as well? Any platform will have many thousands of tonnes of static load, but the figure’s likely to double if a drill-string is included. Water depths and the expected lifetime of the project are other important parameters. And the design will also have to take into account the possibility that yet-to-be-discovered pockets of oil may be linked to the facility in future.

Next, bids are let and contractors selected — a daunting exercise in logistics, procurement and management. “In an offshore facility there are hundreds of thousands of sub-elements electrical generation, data support, and compressors, for instance,” says Bill Dunnett, managing director of offshore drilling operations.

What type of offshore platform does sir require?

Drilling barge: in very shallow, calm waters close to shore, operators sometimes install drilling equipment on a flat-bottom barge that is towed from site to site by tugboats.

Jack-up platform/rig: a jack-up rig is similar to a drilling barge, but has three or more massive legs. After the rig is towed to the site with its legs up, the legs are lowered to the seafloor and then the barge is jacked up so that it rests above the water. When drilling is completed, the legs are raised and the platform is towed to the next site.

Semi-submersible platform/rig: the lower hull of this platform has ballast tanks that are filled with water until it is partly submerged with the topsides above the water. Then the platform is anchored to the seafloor. To move the rig, the ballast tanks are filled with air, making it buoyant. Semi-submersibles are typically used for fields in waters at least 60-90 metres deep.

Sea Star platform: smaller versions of TLPs, Sea Star platforms can operate in up to 1,000 metres of water and are typically used to develop smaller deep-water reservoirs that would be uneconomic to exploit with a larger platform.

Fixed platforms: the rigid legs of these permanent production facilities sit directly on the ocean floor. Fixed platforms are used in water depths of up to 520 metres.

Tension-leg platform (TLPs): long, hollow steel legs extend from these floating production structures to the seafloor and are anchored to piles driven into the seabed. The legs prevent vertical movement of the platform, but allow enough horizontal motion to minimise stress from wind and waves. TLPs are typically used in waters 450 to 2,150 metres deep.

Compliant towers: these drilling and production platforms are connected to the seafloor by narrow, vertical towers that are flexible enough to absorb the impact of wind, waves and currents. The structures are generally used in water depths ranging from 450 to 900 metres.

Spar platforms: the deck of this buoy-like platform, which is designed for deep-water and ultra-deep-water applications, sits atop a giant, hollow cylindrical hull that is tethered to the ocean floor with taut cables and lines.

Drill ships: these ships, designed specially for deep-water drilling operations have a drilling platform and derrick on their deck. Drill strings are extended through a moonhole in the hull and down into the water. The vessels are either anchored or use propellers to continually correct their drift, keeping them directly above the well.

Floating production system: these platforms, typically submersibles or drillships, are positioned over production equipment mounted directly on the seafloor. The production is pumped to the facilities on the platform through flexible pipes called risers.
engineers and operations at Petrofac, an oil field services company. “In addition, there are several thousand sub-contracts on a $500 million project.”

The oil or services company running the project must ensure that all those thousands of bits of kit are compatible with each other, meet the requisite quality standards and that they arrive on time and are — to use a bit of industry jargon — fit for purpose. The late arrival of equipment and materials, or a design flaw, can lead to costly delays and impair project economics.

Real estate on a platform’s deck is expensive, so the engineers are aiming to design platforms that are as small and light as possible, without compromising stability and safety. That means improving layout, miniaturising equipment, removing redundant equipment or using lightweight construction materials. Sophisticated software programmes have proved invaluable, enabling engineers to create minutely detailed 3-D computer models of a facility before a well has been drilled or a pipe ordered.

As well as the on-board facilities — those that separate out the gas and liquids from the production stream, store produced oil and accommodate the crew, for example — scientists are continually looking for ways to reduce the weight of the subsea equipment, from the mooring chains and the risers that carry the oil and gas to the surface to drilling, production and processing equipment. Less weight hanging from the platform = smaller platform = more profitable development.

**Constructing giants**

The platform designers’ vision starts becoming reality at fabrication yards, where the structures are assembled by hundreds of welders, fitters, crane operators, painters and riggers. At the height of the oil boom that peaked in mid-2008, more than 80 rig-building yards — which are usually on waterfronts — existed around the world enabling the growth of the offshore industry.

The yards are immense. The world’s largest, a South Korean facility owned by Hyundai, covers 7.2 million square metres. With huge mobile cranes that can lift as much as 1,500 tonnes, giant pieces of equipment used to roll flat plate into tubular sections and immense buildings with overhead cranes for working indoors in bad weather, the largest fabrication facilities are as impressive as the superstructures they build. And managing them requires broad-ranging engineering and technical skills — and teamwork. “For major structures,” says Ray...
Serpas, an engineering manager at US platform contractor J Ray McDermott, “the engineer needs to work closely with the fabricator and installer, because the loading during the fabrication and installation phases can control a large portion of the design.”

Not all platforms are new. Old oil tankers are sometimes converted into floating, production, storage and offloading vessels. Or a rig that was designed for one field can be adapted for use at another. Reusing old equipment isn’t easy: precision measuring using lasers is necessary to ensure that new bits of kit will fit properly, for instance. But it makes obvious financial sense. For one thing, it’s usually cheaper. And, for another, it’s generally much quicker than building something from scratch. Speed is important because reducing the time it takes to get the oil flowing has a significant bearing on the economics.

Platforms on the move

While transportation and installation usually take less time than other aspects of a platform project, these phases are nonetheless risky and costly. The original design must take account of the tools that will be needed for the installation phase — in some cases, massive, ship-mounted derrick cranes that must be booked years in advance; the world’s largest semi-submersible crane vessel, owned by marine contractor Heerema, has a lifting capacity of 14,200 tonnes. Inadequate early planning can lead to costly rework, equipment availability problems and schedule delays, says Kirt Raymond, a general manager at J Ray.

Often a platform, or part of one, will have to be shipped a considerable distance, from fabrication yard to field, adding another layer of logistical complication. Thunder Horse’s 60,000 tonne hull was constructed in South Korea.

**Anything but straightforward**

Installation methods vary, depending on the type of structure and its location. Take a fixed platform, for example: once the main structural component — the substructure, or jacket, arrives at its destination, it is up-ended from a horizontal to vertical position and lowered to the bottom of the ocean. Then it is levelled and piles are driven through the legs of the jacket into the seafloor. Next, the topsides, or deck, are lifted into place and set on top of the piling. The pieces are connected and other operations required to complete the structure are conducted. Finally, the drilling rig and other equipment modules are put in place.

If it sounds straightforward, it’s anything but. The sheer size and weight of these massive structures add significantly to the difficulties involved in executing each of these steps, making platform design, construction and installation one of the world’s most incredible feats of engineering.
The hydrocarbon compound: the most versatile there is

Crude oil is mainly made up of chains of carbon and hydrogen atoms called hydrocarbons. The chemical bonds that link these chains together can be broken up and linked in different ways.

According to BP, the hydrocarbon compound is the most versatile on the chemical charts — able to make an estimated 2.5 million combinations.

The flexibility of hydrocarbons allows refiners to turn undesirable oil products into more valuable ones. Longer, heavier molecules can be transformed into shorter, lighter ones through a process called cracking, which uses temperature or catalysts to make new combinations of carbon and hydrogen atoms — and yield greater volumes of high-value products, such as gasoline.
"SONANGOL: BUILDING SUSTAINABLE FOUNDATIONS TO GUARANTEE THE FUTURE OF ANGOLA'S OIL AND GAS"

Interview with Mateus Morais de Brito, Sonangol Member of the Board

What is your view about how the oil and gas industry should attract more young people?
Young people should be given the opportunity to develop careers in a way that would help fill the gaps that exist in today’s industry. To help attract, and retain, this talent, it’s also critical that programmes appeal to their day-to-day activities, are relevant to the reality of the industry, but above all, are attractive to their professional aspirations. Working in the oil industry is serious business, but that shouldn’t mean it has to be “boring”. As leaders in the industry, it’s our responsibility to be creative in how we approach this talent pool.

What is Sonangol doing to attract young people to its business?
Sonangol has two well planned programmes for Angolan professionals, designed to develop the careers of our young professionals, by exposing them to the different components of the industry, while also giving them the chance to take a more scholastic (research) or management route through the pursuit of a masters degree and/or PhD, as well as business-management training.

Why has Sonangol’s upstream sector been so successful?
Ensuring its strategies are adapted to the ever-changing global economy, Sonangol is determined to continue to be a leader in both the Angolan and international market. The investment and maintenance of our resources, and the synergies between our younger workforce that bring in new ideas and our more experienced workforce, has been the key to our success.

What are Sonangol and the government doing to promote sustainability in the energy industry?
Sonangol and the government of Angola are partners in various pioneering projects within the energy sector that include the diversification of oil, to the implementation of regulation that will certify the sector is developed in a socially and environmentally responsible manner. It’s important that we develop the multiple sources of energy that exist in the country, without causing damage to the environment or the local communities, and ensure we mitigate the impact of the changes resultant from that development.
Finally, the oil sector, by its very nature, expects that the regulatory agents and the consumers understand their role in guaranteeing that energy is consumed in the most safe and responsible manner.
What is Sonangol and the government doing to develop downstream industries and other infrastructure?
The development of downstream in Angola depends on the creation of infrastructure with the capacity to sustain the demands of the market, Sonangol and the government. Currently, a plan is in place that involves the rehabilitation of the existing infrastructure, such as the Luanda refinery, as well as the construction of two new refineries, one of which will be located in Lobito with a capacity of 200,000 barrels a day. In addition, Sonagnás is currently executing several projects that vary from the evaluation of associated and non-associated gas reserves, to building a network for its sale and distribution.

What are your plans for developing local content? The stage at which Angola’s economics and political development finds itself has accentuated the need to create a sound foundation for the country’s local content. At the base of that foundation, is securing a solid national content strategy. This will involve the coordination of all local content related matters by the ministry of petroleum, the revision of existing legislation on local content, and integrated approach aimed at increasing national content in the industry. Sonangol is ardently working with ministry of petroleum towards attaining this objective.

How are the oil industry and Sonangol transforming the country’s economy and prospects? Although Sonangol is an oil and gas energy company, we invest in several other sectors. The diversification of the economy is fundamental to the growth and development of any country. The synergies between Sonangol and the Government of Angola have strengthened investments across a broad range of sectors, and have resulted in the flourishing of industries, creating a more sustainable economic foundation that will generate more benefits and wealth for the country. This partnership/alignment is indeed the main factor for the huge achievements in this area.

How do you expect the country’s liquefied natural gas industry to develop? LNG has a very specific plan that is aligned with the country’s development strategy, and given the fact that gas is an economically viable and environmentally attractive energy resource, its promotion and the development of a trading mechanism will ease the pressure on the sector. On the other hand, the transformation of the energy sector in Angola promotes investments with the ability to support the expansion of the LNG industry in the long run.

What is the outlook for Angola’s petroleum sector over the next five years? Increased investment in the sector in order to guarantee the sustainability of resources and the long-term maintenance of projects. Increased investment in the international market both in exploration and production, as well as other areas of operations. All this, and seizing upon the opportunity to aggressively, but consciously, invest, during these times of economic strife, will guarantee the continuous development of the sector.
The price of North Sea Brent crude oil, current affairs and the Dalia development

$ a barrel

Source — US Energy Information Administration (oil price)
Dalia: taking the long-term view

Oil companies think for the long term. They tend not to get too excited about very high oil prices or too alarmed by very low oil prices, because a certain amount of price cyclical is a fact of life. Things tend to even out in the end and they base their plans on assumptions about the average long-term price.

France’s Total discovered the Dalia field in 1997. It took over nine years to produce first oil. In 1997, oil prices were around $20 a barrel. But, within a year, they’d halved. Four years later, they started to rise and by mid-2008, just 18 months after project start-up, they reached nearly $150 a barrel. By mid-2009, they’d roughly halved from that level, having nearly fallen as far as $30 in between.

Political cycles are shorter than the oil industry’s planning cycle too, which can be frustrating for oil companies, because politicians sometimes take decisions that might be expedient in the short term, but aren’t necessarily conducive to investment over the kind of horizons the oil industry contemplates. The time between the discovery of Dalia and first oil is about twice the length of a typical government term.

Why did it take so long to get the oil flowing at Dalia? In all projects, but especially those offshore, or in inhospitable, remote and infrastructure-deficient locations, oil developers face considerable physical and organisational challenges. Dalia’s not easy to get to for a start: the field’s 135 kilometres off the Angolan coast. The water’s deep too – ranging from 1,200 to 1,500 metres, over an area of about 230 square kilometres.

Extensive kit is needed to produce the oil and gas: the floating production, storage and offloading (FPSO) vessel being used to produce the oil is one of the largest ever built. The hull is 300 metres in length, 60 metres wide by 32 metres high. On top of it are 29,400 tonnes of deck and facilities (topsides). The vessel can store up to 2 million barrels of oil.

Beneath the water, the project involved the drilling of 71 wells, including 37 producing wells. The network of tubes that transports fluids from the seafloor to the surface is more than 53 kilometres in length. Reservoir conditions are unhelpful: the oil is highly viscous and acidic.

After it’s been cleaned up, water that was produced with the oil is pumped back into the reservoir through 35 kilometres of injection lines and down 31 water-injection wells. Another 13 kilometres of tubes carry natural gas that was produced with the oil back to the reservoir for reinjection.

Co-ordinating this activity takes years, requires the input of numerous equipment and technology suppliers, and thousands of workers. It’s also not cheap: the investors in Dalia spent $4 billion – not the kind of sum on which you make snap decisions. But, with reserves estimated at close to 1 billion barrels and production capacity of around 240,000 barrels a day, the field is worth the investment.
Deep thinking

The energy industry is moving further offshore in its search for the next big oil and gas discovery — spawning technological marvels along the way

Subsea engineering — which deploys sophisticated seabed drilling and extraction devices to winkle oil out of the most inhospitable corners of the oceans — has developed rapidly, and is set to play a growing role in energy supply.

It first came to prominence in the North Sea in the 1980s, and has since been deployed with increasing sophistication in the Gulf of Mexico and the seas off west Africa. And recent discoveries in the Brazilian Atlantic have located vast reserves of oil under 2,000 metres of water and a further 5,000-7,000 below the seabed.

The job of extracting those reserves will spur further breakthroughs by the subsea sector — a thriving industry of large and small companies engaged in marine engineering, chemical engineering, robotics, remote tracking and control, logistical planning and a range of other endeavours that have made this one of the most inventive and exciting areas in the energy world.

Schlumberger, the oil field services company, is one of many firms assisting Brazil in its deep-water developments. Andy Hendricks, vice-president of Schlumberger’s subsea division, defines subsea as “everything that happens between the sea floor and the surface of the ocean.”

Methods of drilling for oil in shallow waters — up to 400 metres — closely resemble the methods used on land, he says. “Onshore, you drill down into the mud until you get to the residue. On conventional platforms offshore, you pipe through the water, but you’re drilling with much the same equipment.” Beyond 400 metres, however, the picture changes.

“Different methods of monitoring are required, different tools and chemical solutions,” says Hendricks. “Wellheads and trees no longer sit on the platform; they sit on the sea floor, in an entirely different environment in terms of pressure and temperature.

“Temperatures at the sea bed are very cold. How do you get the oil flowing? The oil has been there for 40 million years; it doesn’t want to come out. Somehow, you’ve got to lift it to a production facility — a platform or a floating vessel.”

Christmas trees, manifolds, umbilicals, ROVs and jumpers, and all on the sea bed
exceptional people
cutting-edge technologies
extreme environments
borderless careers

Schlumberger is the world’s leading oilfield services company. We provide the highly specialized, cutting-edge technologies and advanced expertise that are essential to satisfying the ever rising worldwide demand for energy.

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usually, subsea systems consist of an intricate network of gadgets installed by that vessel and connecting it to the hydrocarbons miles below. the most important pieces of kit include the wellhead, the component at the surface of an oil well that acts as the interface for drilling and production equipment. it provides a pressure barrier connecting the casing strings that run from the source of the well to the pressure-control equipment. traditionally, the wellhead was located on oil platforms, but in deeper waters it sits on the seabed.

once the well has been drilled, a completion is placed in the well to provide the conduit for the well fluids. the surface pressure control is provided by a christmas tree, which is installed on top of the wellhead. named for its crude physical resemblance to a tree, this is an assembly of valves, spools and fittings, that helps control and regulate the flow of oil out of the well; provides numerous chemical injection points, allowing the oil to be treated; and also sensors, enabling temperature, flow-rates, and flow composition to be measured.

subsea wells and trees connect through flowlines (or risers) to a fixed or floating production platform or to a storage vessel. the riser is the conduit for the oil and must be located miles beneath the surface of the oceans, and sometimes hundred of miles from the shoreline, subsea wells are by their nature remote. that makes drilling and planting these wells a problem. and it makes going back to repair them a nightmare.

maintenance is comparatively easy to perform on equipment based onshore, or in shallower seas, where the wellhead is usually sited on the platform. access to dry trees is easier and can be accomplished more quickly, boosting the total recovery factor. the average onshore well needs between four and five days of intervention a year, but because it takes longer to repair and maintain wet-tree wells, their productivity is lowered. the recovery factor of a subsea well averages about 20%, compared with around 50% for dry-tree wells, says andy hendricks, head of schlumberger’s subsea division.

then there’s the wasteful cost of chartering the kit necessary to make the repairs. this typically means hiring a drilling rig, which has all the hardware required to lower equipment to the floor, and on-board personnel — maybe 100 people. but that vessel is designed to perform other functions, besides repairs, such as drilling. “you don’t need all that equipment just to do an intervention,” says hendricks. and it’s undesirable economically. deep-water rigs can cost $600,000-800,000 a day.

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strong, yet lightweight, to avoid snapping, up-rooting the wellhead, or exerting too heavy a downward drag on the rig. Shell, for example, uses a so-called lazy-wave steel riser on its deep-water projects in Brazil; this shape provides buoyancy and takes some of the load off the floating structure and the set-down point. Much scientific research has gone into composite materials for risers: most consist mainly of steel, but in regions where either the oil or the seawater is especially corrosive, for example, they have rubber linings.

Considerations like this exemplify the challenges facing all subsea equipment: wellheads, trees and tubes all have to be exceptionally durable, as well as sophisticated, to work properly under the weight of up to 3,000 metres of water. The kit needs to be able to withstand the weather extremes that nature frequently throws at it – strong tides, waves, and currents; and hurricanes, earthquakes and icebergs, to name a few. And it needs to meet increasingly tough environmental and safety requirements, and run for years with minimal maintenance.

Then, as Schlumberger’s Hendricks points out, there is the problem of the oil itself. It might be too cold or too viscous to flow on its own, requiring the assistance of giant electrical pumps or heat-transmitting pipes that are lowered down to the seabed. On other occasions the oil will be found at high temperatures, or in a highly acidic state, posing more problems for a producer’s equipment, both under the sea and on the platform.

Oil companies have teams of R&D specialists engaged in devising clever subsea solutions of oil from mature fields in shallow waters and of working for several years without maintenance at depths of 3,000 metres.

Schlumberger has developed a remote-monitoring technology capable of measuring objectively the relative flow contribution of different operators to common pipeline networks in areas such as the North Sea and the Gulf of Mexico – and, therefore, the share of the financial spoils owed to each producer.

Sometimes, subsea solutions are primarily chemical in nature. Schlumberger recently unveiled Futur, an active set-cement technology that automatically self-heals in the presence of hydrocarbon leaks coming through cracks in subsea wells that can occur in extremes of temperature or water pressure.

Many companies have invested in remotely operated vehicles (ROVs). These are robotic pieces of equipment performing tasks on the deep-sea floor that in times past (or in much shallower waters) might have been carried out by human divers. ROVs come in a range of shapes, sizes and functions, from simple eyeball-camera devices to multi-purpose, multi-appendage maintenance vehicles. Subsea engineers are also engaged in developing cables, tethers, buoys and other mooring technology that will keep platforms and production vessels stable in the roughest deep-water seas.

Deep-water applications attract the headlines, but David Pridden, chief executive of Subsea UK, an industry body, says subsea techniques are ideal for tapping relatively small pools of oil and gas in mature areas such as the North Sea, particularly when wells can be tied back to existing production and pipeline infrastructure. Nearly half the relatively shallow UK continental shelf’s output comes through subsea wells, he says.

In an era when the more accessible and relatively easy-to-produce discoveries have been made, and oil producers have long since started looking beyond dry land in their quest for fossil fuels, the role played by subsea technologies has never been more vital.
Producing clever

There is plenty of oil left, but it’s not necessarily easy to produce. That’s where the clever stuff comes in

It’s a surprising fact that most of the oil in a reservoir is usually never retrieved. Eventually, it becomes too expensive to produce and, at that point, it’s time to abandon the project. Perhaps the oil or gas is contained in small, separate compartments, obliging the operator to drill numerous — and expensive — wells to get at the various pockets of hydrocarbons.

Occasionally, as much as 70% of the oil can be pumped out. But in most cases it’s much lower — perhaps just 5%. On average, the worldwide recovery factor is about 35%.

Any technology that can step up the recovery rate and allow the operator to continue pumping oil is valuable for the company producing the oil; increasing recovery at existing fields is cheaper and less energy-intensive than making and developing new discoveries. It’s good for the government receiving taxes from the production too.

And it’s important to world energy supply. According to BP, a 1% increase from its reservoirs alone would yield an extra 2 billion barrels of oil equivalent. On a worldwide basis, a 5% increase in recovery would yield an additional 300-600 billion barrels of oil equivalent, the company says. That would equate to 10-20 years’ of oil supply at today’s consumption rate. And, with oil prices of, say, $70 a barrel, the economic value of such an uplift would be staggering.

“There is a significant amount of oil out there in fields that we already know where they are,” says an enhanced oil recovery (EOR) specialist at US oil company...
Profile — Todd Wise

Name: Todd Wise
Company: Chevron
Present job: Petroleum engineer
Age: 25
Nationality: American
Degree: Petroleum and natural gas engineering, Penn State University

In college, I did three internships in the oil industry — two of them at Chevron. I liked the way the company did business; its values were aligned with mine — its focus on safety, the environment, ethics and the way people are treated. Those things develop trust and a sense of partnership.

I started full-time in 2007, working on heavy-oil projects, using steam floods to enhance recovery. Heavy oil’s viscous, so it doesn’t flow well. Think of pancake syrup: it sticks to itself and anything it comes into contact with, but if you heat it in the microwave, it pours easily. Steam’s the most economic and operationally reliable way of doing the same thing to heavy oil.

I’m based in California’s San Joaquin Valley, managing a heavy-oil steam-flood pilot venture. It’s a test-bed for new technologies and hypotheses — a real project, with all the appropriate wells and data surveillance and all the hardware and the water supply you need for a steam flood, but everything’s scaled down.

Steam floods are typically performed in sandstone reservoirs and we’re looking at ways of using them in other types of reservoirs. Most of the world’s easy oil has been produced, so finding new ways of producing heavy oil and other unconventional hydrocarbon resources is an important part of maintaining energy supply.

The challenges in my present job are different from those I faced in my first assignment with Chevron. I spent my first two years as a reservoir engineer; that involves understanding what’s going on in the subsurface and devising ways of optimising production — getting the most you can out of the ground. It’s a strategic-thinking role; you’re focused on the long term.

The demands of the production side of the business are more immediate. For example, I have to coordinate multifunctional groups — welders, drillers and so on — and ensure that everything we do complies with environmental and safety standards. You have to think on your feet, but I relish the organisational challenges the job involves.

Professional variety is one of the great things Chevron has to offer. In your first five years, you complete three different — and diverse — assignments, which gives you a wide base of experience on which to build your career. My next assignment might be business planning or facilities management, either of which would be a big departure from what I’m doing now.

You get a lot of help from the many experienced people in the company. But lots of young people are coming into the business too, seeing things with a fresh set of eyes. I’m part of a group of young people working together on innovative ways of doing business — coming up with ideas for how we can cut our carbon footprint, for instance.

Some jobs, you’re in the office all day and others you’re always outside. In energy, it’s both. You work in an office — crunching numbers, assessing the economics, speaking with management. But you also have to be out where the rubber meets the road: seeing wells being drilled, cables being laid, trenches being dug and meeting the people doing that work gives you a vitally important perspective on the operation. It’s a mix of strategy and practice.
Chevron. “And the beauty is there is no exploration cost.”

So how’s it done? Underground reservoirs of oil, gas and water are naturally under considerable pressure; when they’re perforated with a well, their contents spurt to the surface — like a can of carbonated drink that has been shaken up and opened. This phase of production is called primary recovery and might push out 10-15% of the oil in place.

But once that natural fizz has dissipated, the oil needs help to reach the surface. Pressure can be maintained by various means. That might involve mechanical devices such as giant electrical pumps. Alternatively, injecting steam into the reservoir can lower the viscosity of sticky oil, enabling it to flow more freely to the surface.

But the most common method of enhancing oil recovery involves injecting water or gas into the reservoir to flush additional oil out through the production wells (see box). These floods — or reservoir sweeps — might bring recovery factors up to something around the 35% level.

But the trouble with injecting water into an oil well is that it’s naturally mobile, pushing quickly through the reservoir without necessarily displacing much oil. At first, only some of the reinjected water will burst back out of the production wells, mixed in with whatever oil it has succeeded in driving to the surface. But the longer the flood goes on, the higher the water cut — the proportion of water in the mix; eventually the water-handling costs outweigh the financial returns of the diminishing volume of oil being produced and the operator will have to admit defeat.

Good chemistry

Or maybe not, if the company is prepared to invest in the next stage of EOR, in which chemicals can be used to squeeze out even more oil — perhaps another 20%.

Chemical EOR might involve mixing a surface-acting agent — a surfactant —

**CO₂ injection: two birds with one stone**

In the past, natural gas was often reinjected into oil fields to enhance recovery, but that’s no longer desirable because hydrocarbon gases are too valuable as energy sources in their own right. The big hope is that CO₂ captured from industrial processes and power plants will be widely used to enhance oil production, becoming permanently isolated from the atmosphere in the process.

Operators in the US have been injecting CO₂ into oil reservoirs to boost oil recovery for decades — experience there suggests CO₂ injection can boost recovery rates by 5-15%. In the US, natural sources of CO₂ have generally been used for EOR. But man-made CO₂ is widely available and the need to deal with it to mitigate the effects of climate change should provide oil companies with a steady supply of the gas in the future.

In fact, the supply of manmade CO₂ that the world will have to prevent from reaching the atmosphere in order to keep global temperatures at acceptable levels is far greater than could be used for EOR purposes. Nonetheless, it’s in the industry’s obvious economic interest to use as much CO₂ as possible for EOR because, at the same time CO₂ is being stored, a valuable commodity is being produced.

CO₂ EOR can be made more effective with the use of chemicals by, for example, mixing a surfactant into the gas that produces a foam when it comes into contact with water. The idea is that the foam is generated when the CO₂ comes into contact with an area that has already been swept with a water flood. The foam blocks the path of the CO₂, diverting it into oil-bearing areas of the reservoir that haven’t yet been flushed out with water.

Given growing determination around the world to deal with climate change and other environmental issues, expertise in this kind of technology will be at a premium.”
with the water being used in the flood. Surfactants act as a detergent, reducing surface energy between water and oil and making oil droplets flow more efficiently through rock formations.

Alternatively, the water can be stiffened up with polymers, making it less mobile so that oil moves more easily in front of the water. This way, the sweep can gather a greater volume of oil from the rock pores. Think giant squeegee forcing oil towards the production wells.

If the oil being produced is acidic, a cheap alkali such as sodium carbonate can be added to the surfactant/polymer mix. The alkali reacts with acid in the oil, naturally creating extra surfactants. Because the surfactants are made naturally and not in a factory, the process is cheaper and — therefore — generates greater returns for the operator.

But the disadvantage of polymer floods is that because they make the water flow less easily, it also becomes harder to inject the fluid, says Andrew Cockin, technology director of BP’s Pushing Reservoir Limits (PRL) programme. BP thinks it may have found a solution to this problem: a substance called Bright Water, which is just making it out of the lab after about 10 years, is a polymer consisting of very tightly bound molecules; because they are so tightly bound, they can be injected into the reservoir — along with water — with minimal resistance and are able to flow unimpeded through the rock.

But things change when the injected fluid comes into contact with hot parts of the reservoir — those that have not been previously swept with water. The tightly bound ball is held together by some weak cross-links and these break down as the

CO₂ has been injected into Norway’s Sleipner field to enhance oil recovery since 1996. The gas is then permanently stored beneath the seabed.
There’s this idea that the oil industry is low-tech — and it’s a major misconception. Before I joined Baker Hughes, I used to think it was just a question of drilling down and pumping up oil, with a bit of mechanical hardware.

I was completely wrong: the technology is extremely complex. It’s technically comparable to launching a rocket. If any aspiring engineer were to become familiar with the technologies we’re working with, I’m convinced they’d want to join the industry.

I’ve been with Baker since January 2008, having spent my first six months after university doing an internship at Cisco, a networking-solutions company. What I’m doing now is the ideal job: it involves engineering and statistics, the subjects of my two master’s degrees. I work on measurement-while-drilling (MWD) tools — electronic measuring devices that are inserted into oil and gas wells along with the drilling apparatus. In the past, measurements taken at the surface didn’t provide accurate information about downhole conditions. The ability to take measurements in the reservoir during the drilling process have substantially improved drilling performance and reduced downtime.

The design parameters are extremely testing. The product I work on — a communications and power-supply tool that, among many other tasks, tells us where we are drilling and which direction to head to reach the reservoir — has 11 electronic boards. They must withstand temperatures of up to 200°C, as well as high pressures and extreme vibrations. My job is to monitor the performance of the electronic components in these boards, and predict the probable remaining lifetime of the tool based on how much it’s been used and on patterns from previous failures. The process provides valuable information to the design and manufacturing teams, enabling them to produce more reliable tools. It’s rewarding, interesting and challenging.

At the moment, my focus is on developing a thorough understanding of MWD technology, which will give me a solid base from which to branch into any other part of the business. That’s a great benefit of the energy industry: there’s plenty of career choice. Baker offers me that freedom to move about, but also a structure within which to work; you know what your role and responsibilities are. There’s also a good balance between experienced staff, with their invaluable stock of knowledge and ability to provide guidance and training, and young people, who are coming in with fresh ideas about how to do things.

I started off in the company’s graduate-training programme called Lead — leadership, excellence and development. It gave me a good grounding in the technology, wider industry issues and an introduction to the business side. If I do well in my current position, there’s the opportunity for more management training further down the line.
temperature rises. That causes the ball to spring apart into something much bigger — something that is either too big to flow through the rock pores or gets tangled up with other exploding Bright Water chains and forms a blockage.

**Stop thief!**

What’s good about a blockage? The reservoir contains so-called thief zones, areas into which water preferentially rushes ahead of the rest of the flood, bypassing valuable pockets of oil before breaking out through the production wells. In the past, thief zones have generally been isolated with the insertion of physical barriers downhole — mechanical plugs, patches, polymer gels or cement. But none of these penetrates very deeply into the thief zones and the injected water can often find its way into the thief zones by other routes.

Bright Water, says Cockin, has the potential to plug thief zones automatically. “The fantastic thing is you don’t have to have detailed knowledge of what the problem is,” he says. “It’s like putting something in a bicycle’s inner tube that automatically finds punctures and fixes them.”

**Low-salt diet**

BP has also been experimenting with changing the salinity of the water it uses to flush oil out of the reservoir. Its LoSal technology, it believes, may be able to add something like 1 billion barrels of proved reserves around the world.

Conventionally, the water used in floods is saline; reservoirs are often injected with seawater, because they’re offshore or close to seawater supplies. “The classical approach is that the salinity of the water doesn’t make any difference,” says Cockin. “But we’ve discovered that it does.”

BP has run several tests that involve taking a rock sample from a well and recreating reservoir conditions — temperature and pressure — in a laboratory, before performing a water flood on the sample with low-salinity water. “We’ve studied over 20 different rock types and, as long as it’s a sandstone reservoir, in every case we get more incremental oil out,” says Cockin. The company’s best result has been a 40% improvement over a high-salinity flood.

About 60% of BP’s oil production comes from water floods, and that is set to climb to 80% by 2010, so anything the company can do to improve water flood performance will have a significant impact on overall recovery.

The lateral thinking doesn’t stop there. Microbes, which exist naturally in reservoirs and are capable of surviving high temperatures and pressures, have potential too. By injecting bugs into reservoirs and feeding them, or adding nutrients to stimulate those naturally occurring in reservoirs, their metabolic activity can be manipulated to give rise to by-products such as polymers, surfactants and gas. In turn, these can help trapped oil to move more freely. Micro-organisms can also degrade the oil itself, reducing the viscosity of heavier oil so that it can flow from the rock pores. Nanotechnology, meanwhile, could one day revolutionise production.
Go with the flow — or cause the flow yourself

Shale gas — natural gas held in rock formations with extremely low permeability — doesn’t flow well. Unless it’s given a helping hand

There’s good news and bad news about natural gas held in shales deep below the earth’s surface. The good news is that exploration in the US is proving that many shales contain very large volumes of exploitable gas.

The bad news is that although shale is the earth’s most common sedimentary rock, only a small proportion is suitable as a potential hydrocarbon source. Most muds, when they’re deposited, don’t contain high levels of organic source material; even when they do, the organic material usually gets oxidized before it can be buried. Only in certain low-oxygen environments does the organic material survive intact for long enough to provide a potential hydrocarbon source.

And even when hydrocarbons are present, it hasn’t always been possible to get at them. Fine-grained shale formations are characterised by low permeability, which impedes the flow of gas (or liquids), making shale an ineffective petroleum reservoir rock.

Get them moving

But oil firms and oil field services companies have developed special production technologies to get them moving. The two main techniques — horizontal drilling and hydraulic fracturing — have been around since the 1950s, but recent refinements have made their use more technically efficient and more economic. In simple terms, both techniques improve the contact between the well and the reservoir.

Hydraulic fracturing — known as fracing (pronounced fracking) — involves the use of powerful pumps at the surface to inject a fluid into the reservoir, typically water with a friction-reducing chemical additive that allows it to be pumped into the formation at faster rates. That pressure fractures the rocks around the well, forcing open new

Conventional or unconventional?

Conventional oil and gas: crude oil and natural gas that is produced by a well drilled into a geological formation in which the reservoir and fluid characteristics permit the oil and natural gas to flow readily to the wellbore (as defined by the US Department of Energy’s statistic arm, Energy Information Administration). The gusher of folklore is the most productive of this type of well.

Unconventional hydrocarbons: any other type of crude oil and natural gas. If it’s oil, it might be thick and viscous — and won’t flow on its own. The biggest deposits are: Canada’s so-called oil sands, containing remaining established reserves of bitumen of 173 billion barrels; and Venezuela’s extra-heavy oil Orinoco Belt, containing ultimate recoverable resources of 272 billion barrels. That puts Venezuela’s unconventional oil resources marginally ahead of Saudi Arabia’s conventional oil reserves, which are estimated at around 264 billion barrels (although Saudi Arabia’s crude oil is much better quality and much easier and cheaper to get out of the ground).

But reserves could increase. What is recoverable depends on technology, which is improving all the time. Total resources in Alberta and Venezuela, mostly unrecoverable with today’s technology, are several times higher.

Shale gas is unconventional because it requires special technology to develop it.
passageways in the reservoir, which lets more gas or oil flow freely to a producing well.

The process involves brute force, but considerable finesse too — it’s all about fracture mechanics, fluid mechanics, solid mechanics and porous medium flow.

**Suitable rock**

First, you need to check the mineralogy of the shale formation is suitable. If it’s too clay-rich, it won’t fracture when fraced, says Ken Chew, a geologist who works for the energy division of IHS, an industry consultancy. It needs to have a sufficiently high silica (quartz) content to make it brittle.

Then, says Robert Kleinberg, an expert on unconventional resources at one of Schlumberger’s research centres, you need to know in what direction the rock is likely to fracture. There would be little point in drilling a well parallel to fractures needed to transport gas to the borehole; the well needs to be drilled roughly at right angles to expected fracture planes. To predict the direction of the fracture, the operator lowers sonic logging tools down a well to measure the speed of sound around the wellbore, says Kleinberg. This information indicates the orientation of the reservoir’s minimum mechanical stress.

As they open up, the fractures are carefully monitored — using micro-seismic sensors placed down several wells — to ensure that what was predicted would happen did happen. The sensors pick up acoustic emissions from the fracturing process, allowing the drilling company to determine how the fracture is propagating — much like the epicentre of an earthquake would be identified. That information can then be presented in 3-D, showing the zones that haven’t yet been reached.

The trouble is that as soon as you stop pumping, the cracks that the fluid has opened close shut. So the fluid
contains sand — or some other so-called proppant — that gets into the cracks and keeps them propped open after the pumping stops.

**Going horizontal**

But before you frac, you drill. Imagine what happens when a vertical well penetrates a layer of rock steeped in oil or gas that is 10 metres from top to bottom: 10 metres after entering the top of the thin horizontal hydrocarbons-bearing layer — or payzone — the drillbit would grind its way out of the bottom into the next formation down, only coming into contact with 10 metres’ worth of productive rock. Once it had drained the oil or gas in its immediate vicinity, hydrocarbons from elsewhere would migrate towards the well — but far too slowly to be of practical use, especially in a low-permeability rock.

Horizontal drilling can significantly boost the amount of gas or oil that can be recovered with a single well. Steer the drill-bit sideways as soon as it hits the target layer and continue drilling laterally instead of downwards and productivity is multiplied, because the well can stay in the formation for much greater distances — theoretically for as far as you can drill. Downhole instruments called measurement-while-drilling (MWD) tools, placed on the drill-bit, transmit sensor readings to the surface, allowing the operator to determine the required trajectory.

The oil industry has plenty of experience of horizontal drilling in conventional oil and gas operations: in 2008, Danish company Maersk Oil drilled a well in Qatar with a 10.9 kilometre horizontal section — a world record. The limit continues to be pushed: BP, for example, expects to beat that soon, with horizontal wells of up to 14 kilometres at Alaska’s Liberty field and is considering a 16 kilometre horizontal well at its Wytch Farm project in the south of England.

In US shale-gas developments, horizontal wells are reaching lengths of up to 1.5 kilometres. The well bores are fractured in stages — typically 500 foot sections — in order to concentrate pumping power. The result is a significant improvement in reservoir contact.

Counter-intuitively, despite the monumental amount of hardware and manpower needed for injecting the fracing fluid (see photo) and the technology required for horizontal drilling, shale gas production remains cost effective in several basins in the US, even at low prices. That balancing act — developing cutting-edge technology at an affordable cost — is something that the oil and gas industry has been perfecting since the modern exploration and production (E&P) business began in the mid-19th century.

Indeed, so successful have E&P companies been in achieving this balance in their drive to develop the US’ shale-gas resources over the last five years that they have transformed the country’s — and the world’s — gas supply outlook for decades.

**US’ unconventional approach**

Five years ago, US energy firms were fretting about how they were going to import enough gas to meet the country’s rapidly rising needs; suppliers set about building regasification terminals so that they would be able to import enough liquefied natural gas (LNG) to avoid shortages — and head off price spikes.
But there’s since been a big shift in market fundamentals, partly because the recession has temporarily softened gas demand, but also because of spectacular exploration success in the country’s extensive shale-gas deposits. Enterprising E&P companies — helped by favourable tax rates and these advanced drilling and fracturing techniques — have transformed the long-term possibilities for the US’ energy mix.

Shale-gas development is still in its relatively early stages, so estimates of the country’s potential vary. But mostly the numbers are big: its shale-gas basins may contain up to 22 trillion cubic metres of gas, says the Gas Technology Institute, a not-for-profit US research and development organisation for the gas industry. A report funded by the American Clean Skies Foundation (ACSF) estimates that recoverable natural gas supplies in the US amount to 64 trillion cubic metres, including shale-gas resources — which would be equivalent to 118 years of supply at today’s consumption rate.

Production potential is promising too. The US Natural Gas Supply Association, which estimates that gas from shale plays supplied 10-12% of US gas demand in 2008, says the resource’s contribution could double in the next 10 years, providing a quarter of US supply. For now, the US’ most productive basin is the Barnett Shale, near Dallas, Texas, which accounts for about 70% of North American shale-gas output. Between 2000 and 2007, 4,200 horizontal wells were drilled there.

Big prospects

Other big prospects include Oklahoma’s Woodford Shale; Arkansas’ Fayetteville Shale; the Marcellus Shale, which stretches from West Virginia, up through Pennsylvania and into western New York; and Louisiana’s Haynesville Shale, which Ziff Energy, a consultancy in Canada, says will become the largest of the unconventional plays.

But the rate of development depends on the price companies think they will be able

In 2008, Mærsk Oil drilled a world-record horizontal well at the Al Shaheen field in Qatar

Clash of the supercontinents

Many sediments are pushed lower by the slow accumulation of overburden. Over millions of years, the gradual increases in pressure and temperature that occur as a result cook organic material into hydrocarbons — oil and gas.

But this isn’t what happened during the formation of the most important gas-shale reservoirs. “The real story is much more dramatic,” says Schlumberger’s Robert Kleinberg. In the Barnett shale, for example, sediments were deposited in the Mississippian age, when Texas was under water. During the Pennsylvanian and Permian, Gondawana, a supercontinent, collided with another, Laurussia, pushing these sediments down more than 4,250 metres in about 50 million years. “This is when gas was generated,” says Kleinberg. Subsequently, the overlying mountain range eroded during the Triassic and Jurassic, and the depth of the Barnett sediments below ground level decreased to about 2,600 metres, where they remain today.
to secure for the gas. For now, drilling activity has slowed down, because of the sharp drop in gas prices since mid-2008, threatening the economics of some developments. Yet, despite the temporary lull in drilling, North America’s shale-gas resources are of great strategic value: they are an indigenous source of production, lessening reliance on imports. And when recovering demand pushes prices high enough, exploration activity will accelerate — keeping a cap on the cost of imports.

Gas from coal seams
Shales aren’t the only source of unconventional gas. The US is also a world leader in exploiting gas held in seams of coal (see box). Indeed, the coal-seam gas industry is the most developed of the unconventional gas businesses. But shales have greater potential: the volume of gas that can be produced by each well tends to be large, which is important because the economic value of the gas is more likely to justify the expense of investing in pipelines.

Whereas a coal-seam gas well would typically produce something in the order of 6,000 cubic metres a day of gas, some horizontal wells in the Marcellus Shale have been coming on stream at 184,000 cubic metres a day and in the Haynesville Shale at almost 480,000 cubic metres a day, says Chew.

There’s also considerable reserves upside in the shale-gas sector, in which ultimate recovery rates are generally low. You might expect to recover 60-70% of the gas in place in a conventional well, but in gas-shale reservoirs the figure might typically be 10-20%. “You’re leaving a lot of gas in place, which nobody likes to do,” says Kleinberg.

And while the US may be driving development at the moment, there is plenty of potential elsewhere. The enterprising techniques being developed in North America are likely to be replicated around the world — possibly significantly increasing the gas resources that are available worldwide.

Coal-seam gas: another unconventional story
Unconventional gas comes from different types of geology. One of the most highly developed segments of the business is coal-seam gas (CSG — also known as coal-bed methane or coal-bed gas). Natural gas adsorbed onto the surface of coal seams, CSG is extracted from coal seams too deep or too thin to have been mined.

There are numerous CSG developments in North America and Australia. Indeed, such is their prospective value that competition for control of Australia’s CSG deposits has become intense; several ventures have recently been set up with the aim of liquefying gas produced from these deposits for export to buyers in Asia and South America.

Difficult to tap
CSG is the least prospective source of unconventional gas, however — largely because the seams in which the gas is contained are so thin. That not only means that they contain less gas, but also that it is technically more difficult to keep the well in the right part of the formation. It’s a lot harder to drill a horizontal well through a formation that’s 1 metre thick than through one that’s 10 metres thick — go a few centimetres too high and the drillbit could break out of the coal seam. Finding it again could be difficult.

Another problem is that initial flow rates from coal beds tend to be low. As a result, operators struggle to achieve sufficient production to pay for pipelines to take the gas to market. The deposits are also at shallow depths, so the gas is under less pressure. That means expensive compression equipment is necessary to get the gas flowing properly. CSG is better suited to areas where gas pipeline infrastructure already exists or to being converted to electricity at the point of production.
5.6 — Technology: pushing boundaries

Invasion of the algae-heads

It’s green and unglamorous, but it could become ... green and glamorous

Needing just sunlight, water and carbon dioxide (CO₂), algae — pond scum, if you prefer — have the potential to convert solar energy into fuel for cars, homes, planes and power generators, as well as chemical feedstocks for plastics and pharmaceuticals.

Algae are the holy grail of the world’s fuel-supply problems, say algae-heads: they grow very rapidly, they’re rich in vegetable oil and they don’t need fertile land or fresh water — so large-scale cultivation won’t necessarily have a negative impact on food and water supply.

Algae — of which there are more than 100,000 strains — can double their mass several times a day and produce at least 15 times more oil per hectare than alternatives such as rape, palm, soya or jatropha, says Shell, which is working on various advanced biofuels schemes, including algae.

Byrne and Company, a US renewable-energy firm, says the average yearly yield per acre can produce almost 5,000 US gallons of biodiesel, compared with 70 US gallons per acre in the case of soybeans and 420 US gallons of ethanol per acre from maize (known as corn in the US).

Byrne and Company says the sunny US state of Arizona alone has the potential to produce up to 40-60 billion gallons of liquid fuels a year — a large chunk of the 200 billion US gallons of gasoline and diesel the US consumes every 12 months. There are plenty of cattle in Arizona too: dung and wastewater from the livestock industry is a handy source of fertilizer and water for the algae business.

That’s another big plus — algae don’t need clean water. Aquaflow Bionomics, for example, produces biodiesel from wild micro-algae sourced from sewage ponds in
New Zealand’s South Island. It has also produced samples of a synthetic jet fuel.

Algae can clean up the air too, sucking up waste CO₂ directly from industrial facilities, such as power plants or cement factories. That has two benefits: not only do algae remove CO₂ from the atmosphere, but the concentrated stream of CO₂ should have the effect of turbocharging the algae production.

And although algal fuels release carbon when combusted, the process has the potential to be carbon neutral because algae — like other biofuels crops — take CO₂ out of the atmosphere when they’re growing. Only algae do it more efficiently than other plants, says Tom Byrne, head of Byrne and Company and a board member of Seattle-based Algal Biomass Organization, an industry body representing algal biofuels firms. Byrne says algae are six times more efficient than most land-based plants are at absorbing CO₂ and converting it into plant mass.

The science bit

So, what does the process involve? The idea’s simple enough: algae produce vegetable oil naturally — as a way of storing chemical energy. And that oil can be extracted and utilised.

Algae are placed in water, given the right nutrients and then exposed to sunlight. Photosynthesis converts CO₂ into sugar, which is then metabolised into lipids — oil. The water is then removed in as energy-efficient a way as possible — important because the energy expended in the production process has to be taken into account when evaluating the net energy value of any biofuel or its carbon footprint.

Extraction methods include physically squeezing out the oil, applying compressed CO₂ to vaporize the lipids, which can then be recondensed, or using solvents and even sonic waves. A catalyst then removes oxygen from the oil and replaces it with hydrogen molecules, making a hydrocarbon fuel. Refiners can change the length of carbon chains to convert the algal oil into gasoline and jet fuel. The leftovers of the treated algae can even be used in other products, including animal feed.

Until now, algae have mostly been grown for the pharmaceuticals industry, in relatively small quantities and at relatively high costs. For the fuels business, cultivation must be inexpensive and production quantities must be high if the industry has any chance of offering an alternative to petroleum-based fuels and supplying a significant proportion of the world’s fuel.

The cheapest cultivation system involves open ponds, which are easy to build. The trouble with that is that algae are exposed to the atmosphere. Temperature changes, evaporative losses, diffusion of CO₂, predators and competing algae strains can cause problems. In addition, light use is relatively inefficient and large areas of land are needed.

Greater control over the local environment — at a significant step-up in cost — can be exerted by using photobioreactors (bioreactors incorporating a light source, usually something like enclosed plastic tubes).

Valcent, a US company, operates what it claims is the world’s first commercial-scale bioreactor pilot project, in El Paso, Texas; it uses a vertical-growing system, cultivating algae in pockets built into tall, hanging plastic sheets. By making much better use of theoretically limitless vertical space than in conventional agriculture, Valcent is able to reduce the physical footprint of its farming operation — a principle that should allow food or fuel supplies to be grown in large volumes closer to urban centres.
ises better economics and a lower carbon footprint. The closed system allows it to control the temperature and chemical composition of the algae solution; enhanced control, says Valcent, means maximum oil output.

HR BioPetroleum and Shell, working together on a test project in Hawaii (where better to locate a research project?), have taken a hybrid approach that incorporates open ponds and photobioreactors. They plan to cultivate algae in enclosed photobioreactors, before moving them to frequently harvested open ponds, allowing them to grow at scale without leaving them exposed to contamination risks for too long.

San Francisco-based a, which is collaborating with US oil major Chevron, takes a completely different approach: rather than using photosynthesis, it keeps its algae in the dark, feeding them sugars, which they convert into oils. Its biodiesel meets US fuel standards and, in 2008, it produced what it claims is the world’s first microbial-derived jet fuel.

Given all the promise, there is — inevitably — a degree of hype surrounding algal biofuels. The reality is that they haven’t yet moved into the commercial age and a considerable amount of research and development is needed to make them competitive with petroleum fuels at the kind of scale that would be required to make a meaningful dent in CO₂ emissions.

Nonetheless, research and commercialisation efforts are advancing rapidly. And so too are demonstrations and practical applications. Numerous start-ups, big energy firms and other areas of industry are taking an interest. In 2008, for instance, Virgin Atlantic became the first airline to operate a commercial aircraft using a biofuels blend, flying a Boeing 747 from London to Amsterdam on a mixture of 20% biofuel and 80% regular jet fuel.

As the technology gets out of the hands of laboratories and universities and into the hands of entrepreneurs, the industry will start to gather the commercial momentum that might, one day, see it fulfil its promise.
Exploration and production: explained

Outside the military, oil is the most technology-dependent industry there is

Imagine planning the evacuation of a city — on a moonless night, from a helicopter. You have a basic idea of the road layout, an understanding of how towns are generally planned and the odd scrap of local information. But just a few lampposts are switched on and you are working in darkness.

Producing oil or gas from a reservoir is very similar: a well is like a lamppost — illuminating its immediate surroundings, but nothing more. Seismic information provides a sketchy street plan and maybe some snapshot indications of how conditions are changing with time. Knowledge of geology and science give enough rules of thumb to make reasonable assumptions about what might be down there.

Working in the dark

But reservoir engineers — whose job it is to come up with a plan to squeeze as much as possible out of every cubic metre of rock — are basically working in the dark. They must make multi-million-dollar decisions on the basis of incredibly small amounts of hard information.

It’s an empirical process: once a well is drilled, they must listen to how the reservoir responds and adapt to events as quickly and creatively as possible. You make a theory, act on it and test it. Then you get the results, interpret them and intervene to optimise your plan. But there is a degree of risk and uncertainty that you have to live with all the time.

Risk is inherent in all stages of the oil and gas E&P process. Operations often take place in remote locations and physically harsh environments, with little or no infrastructure. After discovery, oil must be brought to the surface, transported, refined and delivered to the end user — safely, profitably and without spillages.

And the financial stakes are very high: the bill for an offshore wildcat well — where the well planners have little knowledge of the subsurface geology — can easily run to $100 million. In 2007, Brazilian oil company Petrobras drilled one off the Brazilian coast that cost $240 million.

So how do you go from surveying dunes in a desert or waves on the ocean to the point of being prepared to spend $240 million finding out what lies beneath it? The short answer is: science and technology.
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J. Ray McDermott is a leading worldwide engineering and construction company whose services include the design, procurement, fabrication, transportation, installation, hook-up and commissioning of offshore fixed platforms, floating facilities, pipelines, and subsea infrastructure, umbilicals, risers, and flowlines.

I joined J. Ray’s engineering group straight out of college in 2005 and immediately found myself involved in offshore project work – helping install a series of platforms for the Mexican national oil company, Pemex.

I am based in Houston, but during my first year of employment I worked in Mexico for one week of every month. That was a really exciting introduction to the energy business and gave me hands-on experience that has proved invaluable ever since.

Field experience is an important part of working for J. Ray. It makes you a much better engineer, because it provides you with insights into the practical side of the job. Without a proper understanding of the constructability and physical challenges involved in construction, transportation and installation, you’re going to struggle to do the design-side of the job properly. I came into the Pemex project about half way through, but still had the opportunity to see the loadout or installation of 10 different structures that J. Ray was contracted to install.

My next big assignment was for a production platform offshore Trinidad and Tobago in 530 feet of water off the northwest coast of Trinidad. It’s the largest facility ever built or installed in the country’s waters. I was involved in each phase of the project, from preliminary design work to installation.

We won an internal company excellence award for this project, which was very satisfying.

The job involved a great deal of creative thinking. For example, the platform’s substructure is fixed to the seabed using a series of giant piles that are driven into the legs and then about 370 feet into the subsurface. These protect the installation from huge waves and adverse weather conditions.

I was tasked with figuring out a way of transporting those enormous pieces of equipment to the site and designing a system for getting people into the right positions to un-tether them and oversee the installation process. It might not seem like an obvious challenge, but it’s essential to get that kind of thing right without compromising safety.

My career could go in various directions. J. Ray’s an international company with offices all over the world, so I could work abroad. I might do another course of study, although one of the great advantages of working in this business is that you can get to a good level of seniority and responsibility without necessarily taking a Master’s degree or a PhD. The company does actively support employees who take continued education.

Eventually, I could see myself becoming a supervisor within my department, before moving on to management. But at the moment I’m focused on technical-analysis work, and I’m really enjoying it.

I love my job; I work hard, but I go home each day not ever thinking I should do something else. It’s challenging and every day is different. Not many people keep learning at the same rate after leaving college.
6.1 — Understanding oil and gas

True, the first step in the exploration process is political and commercial, not technical. Development permits must be secured. And companies must carefully weigh up geological potential, political risk and the investment terms on offer before embarking on an expensive exploration campaign.

However, once those hurdles have been cleared, the scientists move in. Technology cannot change geology, but it can — and has — improved the chances of finding oil and gas and, equally importantly, finding ways of producing it profitably.

When oil exploration began in the US 150 years ago, drilling was mostly done around visible oil seeps at the earth’s surface. Now E&P operations are common in waters far offshore in depths of over 2,000 metres and technology continues to push the boundaries of what can be commercially produced. In that century and half, millions of wells have been drilled and exploration techniques have been gradually refined, reducing the risk of drilling a dry well — the explorer’s nightmare — to as low as one in three or four.

The kit has got better too. In the mid-19th century, wells were drilled by hammering steel pipe into the rock. Now, a rotary drilling bit — a revolving steel bit at the bottom of a string of pipe — grinds its way through the rock layers, lubricated by special drilling fluid.

But first earth scientists must identify the right rocks. An oil field is like a sponge, not some vast underground lake of oil: oil and gas accumulate within porous rock formations in the earth’s crust over millions of years. A layer of impermeable rock on top stops the oil and gas from escaping.

Geophysicists start to identify suitable rocks by measuring their gravitational and magnetic properties. Soft, sedimentary rocks, such as limestone, which are capable of holding hydrocarbons, are less dense than heavy, igneous rocks. Aeroplanes measure the earth’s gravitational pull; small differences caused by variations in the density of the underlying rocks provide vital clues about the geology. Variations in the earth’s magnetic field can provide useful data too. The less magnetic the better — sedimentary rocks are virtually non-magnetic.

This sort of evidence is enough for the petroleum industry’s earth scientists — geologists, geophysicists, geochemists and palaeontologists — to begin to build a picture of what the subsurface is likely to hold. But it’s nowhere near enough to bet $100 million on. The next step is seismic — where exploration starts to get really serious (see p49).

Seismic shocks
Seismic identifies the best point at which to drill, but the evidence at this stage remains circumstantial. “When you do a seismic survey, you have no idea whether the rock you’ve mapped contains oil or not,” says a field engineer. “Drilling is the only way of getting hard proof that hydrocarbons are present.”

Lengths of drillpipe, tipped with the drill bit, are lowered into the hole from the drilling rig — or derrick — and new sections of drillpipe are added as the hole becomes deeper, telescoping down in ever decreasing sizes. When the total depth of a well can amount to many kilometres, that requires precision engineering. As one engineer puts it, oil exploration is “a brutally heavy industry with amazing finesse”.

Get drilling
When drilling starts, rock fragments flushed out by the drilling fluid — known as mud — are regularly sampled and examined by geochemists for traces of oil. As the well is drilled deeper, a more detailed picture is built up of
6.1 — Understanding oil and gas

the stratigraphic sequence outlined by seismic, through a process called well logging. Derived from the word log in the sense of a record, logging involves lowering a tool down the well on an electrical wire to measure the properties of the rock around the borehole.

The core measurement is resistivity — essentially the same as the breakthrough innovation made by Conrad and Marcel Schlumberger in 1927.

The brothers Schlumberger measured the electricity resistivity of rocks in oil wells to determine the nature of that rock and whether it could, theoretically, hold oil. The measurement of the speed of sound along the borehole wall and radioactivity logs also yield data on the thickness and depth of reservoirs and their probable content.

After a discovery has been made, appraisal wells are drilled to determine the size and composition of the reservoir, which will consist of water and either oil or gas — often both. The all-important question that the exploration company needs answered is whether the reservoir can be produced profitably. There are lots of reasons why a discovery might not be economic even if oil and gas are present. The field might consist of multiple reservoirs and faults, which is technically more difficult — and expensive — to produce. If it’s offshore, it may not be practical to drill the necessary number of wells from one platform. Perhaps the oil is too thick and viscous to pump to the surface without special — and expensive — equipment.

**Heavy duty**

After drilling, steel pipe called casing is set in the hole and is cemented into place (see diagram). A heavy-duty system of valves called a Christmas tree is positioned at the wellhead to control the flow of the oil, gas
and water and prevent a blow-out — high pressure downhole can cause oil and gas to spurt out of a well, often with dangerous results. The well casing is perforated at the right depths to make holes for the oil and gas to flow into the drilled shaft — or wellbore — and up to the surface.

The first recovery phase is called primary recovery. Underground reservoirs of oil, gas and water are under considerable pressure and their contents flow naturally once perforated. But eventually the reservoir runs out of natural energy and the oil needs a helping hand to move to the surface. That’s where enhanced-recovery techniques come into play (see p67).

**Horizontal drilling**

In some places, in-fill drilling will work — sinking clusters of wells into the same area so the oil does not have to migrate as far through the rock to reach a wellbore. But in deep water, when price tags of up to $100 million start being waved around, it will not be economic to drill more than a few wells, so placement is the name of the game. In this situation, directional wells, which can be steered downwards, sideways, horizontally and even upwards, are often used. In the right circumstances, they can prove a much more effective way of tapping an oil field than vertical wells.

The North Sea’s Clair field, in the Atlantic, off the Shetland Islands’ west coast, was discovered in 1977. But although it was estimated to contain a staggering 5 billion barrels of oil — putting it on a par with the prolific Forties field, a giant of the North Sea — BP had to wait 27 years to start developing Clair.

The problem? Clair’s oil is contained in a very fractured reservoir and in the 1970s there was no way of producing commercially from any section of the field. Indeed, many experts predicted at the time that it would never be exploited. Improvements in seismic mapping and the arrival of horizontal drilling changed that.

Horizontal wells cut through a greater length of the reservoir and can link up isolated sections. Well for well, horizontal drilling is far more expensive than vertical drilling, but in the right circumstances, productivity gains make the extra investment worth it.

**The end-game**

Once the field’s recoverable reserves are exhausted, infrastructure must be decommissioned. After years of intense exploration, a wave of decommissioning is starting in mature provinces such as the US and the UK North Sea. It has become imperative for decommissioning to be handled with the utmost sensitivity to the local environment. Yet, once E&P teams are long gone, oil fields have another use: they can serve as storehouses for the carbon that is produced by fossil-fuel processes and removed through the evolving technology of carbon capture and storage. So they can be part of the future as well as part of the past.

![A typical oil well diagram](image-url)
Refining and petrochemicals: explained

Crude oil straight out of the ground is pretty useless, but it becomes extremely useful after being refined into oil products such as gasoline, diesel and jet fuel.

Indeed, it can be invaluable: if you ran out of fuel during a drive through the desert and were 200 kilometres from the nearest water source, would you rather have 50 litres of water or 50 litres of gasoline?

Refineries come in many different sizes and configurations, depending on the size of the local market, the types of products needed and the types of feedstocks available for processing. But they all perform the same basic tasks: distilling crude oil into its various constituent fractions; chemically rearranging low-value configurations of hydrocarbon molecules into high-value combinations to produce a variety of end-products, from gasoline to Tupperware; and treating those products to meet environmental and other specifications and standards by removing impurities such as sulphur.

Carbon chains

Crude oil can be split up into molecules of carbon and hydrogen in a variety of combinations through the refining process. Depending on the length of the chains within them, they can be used in a variety of ways. For example, molecules used for cooking gas usually have up to four carbons, while gasoline for cars is a longer chain, of up to 12. Lubricants — motor oils, for example — are even longer, with perhaps 50 carbons.

The different chain lengths in petroleum have different boiling points, so they can be separated by heating the crude and distilling the resulting vapour (see p91).

The first step is heating up the crude oil — once impurities such as water and salt have been removed from it. The heat is often generated by burning fuel oil in a furnace.

The vaporised petroleum, heated to about 350°C, is pumped into a fractionating tower — or atmospheric pipestill. As it rises up the tower, it cools down and its components condense back into several distinct liquids, collecting in a series of trays. Lighter liquids, such as kerosene and naphtha, a product used in chemicals processing, collect near the top of the tower, while heavier ones such as lubricants and waxes fall to the bottom.
In addition to the various desired fractions, the process also produces a thick, heavy residue. This can be processed further in a vacuum-distillation unit, which uses a combination of high temperature and low pressure to make more useful products. At this stage of the refining process, jet fuel is pretty much ready for use in an aircraft, but most of the products aren’t finished: they’re blendstocks or feedstocks for other processes. A combination of further heating, pressure treatment and the use of chemical catalysts is used to break the chemical bonds that link these chains together and reconfigure them into new combinations, yielding a host of desirable products, such as gasoline. It’s called cracking.

A catalytic cracker can handle a number of feedstocks, including heavy gasoil, treated fuel oil and residue from the lubricant treatment plant. Mixing the feedstock with a hot catalyst enables the cracking reaction to take place at a relatively low temperature (about 500°C). The products are then separated in a fractionating column.

Another refining process, reforming, uses heat and pressure in the presence of catalysts to convert naphtha feedstock into higher-octane, gasoline-blending components.

The finished products — with marketable octane ratings and specific engine properties — are then stored in tanks on the refinery’s premises, before being loaded onto barges, ships and trucks, or into special pipelines for transportation to market. Not surprisingly, big petrochemicals complexes are often found close to big oil deposits, or on the coast, so crude can be easily imported and products easily shipped out.

**Cracking move**

To get more value out of their processed crude, energy companies shift into the realm of the petrochemicals plant, which uses petroleum-based feedstock — naphtha, for instance — to create new products, such as the plastics to be found in a welter of everyday products, from computers and mobile phones to cars and toys.

This is achieved by converting the feedstock into substances such as olefins (a group that includes ethylene and propylene) and aromatics (the distinctive smelling chemicals like benzene and toluene). These in turn provide the foundations for a range of familiar materials, including polyester, vinyl acetate, polystyrene, polyurethane, detergent alcohols, synthetic rubber and many more products.
What you get from a barrel of crude oil

- Finished motor gasoline (45%)
- Distillate fuels (23%)
- Kerosene-type jet fuel (8%)
- Petroleum coke (5%)
- Still gas (4%)
- Residual fuel oil (4%)
- Asphalt and road oil (3%)
- Petrochemical feedstocks (2%)
- Liquefied refinery gases (2%)
- Propane (2%)
- Other (2%)

Based on average output of refinery products in the US in 2007
Getting from one substance to another varies in complexity. For example, converting ethylene into polyethylene takes one process, while producing nylon from benzene takes at least seven steps.

The dizzying oil-price inflation of recent years, which pushed prices to almost $150 a barrel in mid-2008, spawned a wave of new refining and petrochemicals projects in the Middle East, Asia and Latin America — keen to cater to booming demand for refined products, especially in high-growth markets such as China and India.

The economic downturn and lower oil prices have put a damper on the development of some projects with borderline financial viability, but the world is not about to stop using plastics, gasoline, jet fuel or any of the other products produced by the petrochemicals sector.

One of the biggest of the present crop of new facilities — combining a refinery and petrochemicals unit — is being built at Rabigh on the Saudi Arabian coast. For $10 billion, Saudi Aramco and its partner, Japan’s Sumitomo Chemical, will expand an existing 400,000 barrels a day refinery with a 200,000 barrels a day vacuum-distillation unit, a catalytic cracking unit and an alkylation unit. They are also constructing a cracking unit that will produce up to 1.3 million tonnes a year of ethylene to supply a petrochemicals-derivative plants manufacturing polyethylene and mono-ethylene glycol (MEG).

These products will find markets across the world, as they are among the petrochemicals most widely used. Polyethylene is better known as polythene, the substance that forms the basis of many consumer products, from shopping bags to shampoo bottles. MEG is used to make polyester, which, as a fibre, is found in clothes and many other textiles. MEG is also an important element in manufacturing antifreezes and solvents.

A high olefin, fluidized catalytic-cracking unit under construction at the Rabigh plant will produce 900,000 tonnes a year of propylene and 59,000 barrels a day of gasoline. The propylene will be used in the petrochemicals derivative unit to manufacture polypropylene, which is used to produce packaging, textiles, plastics and a lot of other items.

Without the products from petrochemicals plants such as Rabigh our world would look very different, stripped of many of the goods we take for granted.

**Hi-tech challenges**

Indeed, just churning out the stuff we already know how to make isn’t an option for companies to remain competitive and profitable. They need to create new products and find cheaper ways to do things, which is where a good research and development department comes in. The chemical and manufacturing processes in this part of the downstream business require a huge pool of expertise — and a lot of money — to ensure engineers and scientists continue to make breakthroughs. The drive to produce more with less, and more cheaply, provides researchers with access to the sort of facilities rarely found beyond the commercial sector.

Keeping costs down is vital, because the facilities are expensive to build, maintain and run. Refiners and petrochemicals producers must also contend with continual volatility in the prices of the commodities that they produce, planning in years when profits are high for times when margins are low.

And, of course, environmental issues are now a vital part of research in the sector, so firms have to focus on how the industry can meet the increasingly stringent quality standards now required of oil and petrochemicals products.
Fractional Distillation

Crude oil is heated until it vaporizes — to 350°C plus. The resulting gas is pumped into a tall, thin tower called a fractioning column, or pipe still. The vapour rises up the tower, passing through a series of trays with holes in them; as it rises, it cools down, condensing back into several distinct liquids. Lighter fractions, such as kerosene and naphtha, collect near the top of the tower; heavier fractions, such as lubricants and waxes, fall through weirs to trays at the bottom. Engine fuels such as gasoline are then processed further elsewhere in the refinery, before being trucked out to filling stations or other market outlets. The heavy bottom fractions often undergo further treatment to convert them into more useful products (see p89).
In the US, which has more refining capacity than any other country, the sector is, in the words of the US Department of Energy, “one of the most heavily regulated industries”. If plants don’t comply, then they can’t operate. Companies have also had to be flexible enough to adapt to gasoline legislation that varies from state to state, requiring many different products to be created for sale within the US.

The refining sector is also having to adapt to new challenges, as feedstocks diversify to include oil from unconventional sources, such as oil sands and oil shale. These feedstocks require different refining techniques from those used to process conventional crude oil.

Heavy duty

Oil sands produce a very heavy form of crude, known as bitumen, which must first be upgraded in special units into synthetic oil, before being refined. Oil from shale has less hydrogen, and more sulphur and nitrogen compounds in it than conventional crude, so it needs to have hydrogen added and the impurities removed by extra chemical treatment before it can be processed. These extra steps make both shale and oil sands processing an expensive proposition compared with crude refining, but one that is deemed worthwhile if oil demand — and the oil price — is high, as it was until recently and will be again in the not-too-distant future.

Even when you’ve refined your oil and created your petrochemical product, that’s not the end of the story. The industry still has to get the right products to the right customers and that involves massive infrastructure, encompassing road and sea transport and gasoline stations, knowledgeable marketing and sales personnel and many other links in the commercial chain all pulling together to ensure that what emerges from the ground as useless sticky goo can oil the wheels of the global economy.

Oil products: explained

Motor gasoline/petrol
The most common form of gasoline, this is light hydrocarbon oil used in internal combustion engines. It is distilled from crude oil at between 35°C and 215°C. It can include additives such as oxygenates to reduce the amount of carbon monoxide created during combustion, as well as octane enhancers. It can also be mixed with ethanol.

Octane rating: this measures the resistance of fuels such as gasoline to detonation (or knocking) in an engine. The rating is derived from comparisons between a given fuel and a benchmark mixture of iso-octane and heptane. Higher octane ratings are more suitable for higher-performance engines, whose greater compression ratios make the gasoline used more likely to detonate.

Jet fuel
This kerosene-based fuel may be tailored from many different types of hydrocarbons to run aviation-turbine power units. It needs to satisfy a welter of strict international regulations and usually has a freezing point of lower than -40°C to cope with cold temperatures at high altitude. It is similar to diesel fuel. Aircraft operated by piston engines run on a different fuel — aviation gasoline (avgas). This has a high octane rating and more closely resembles motor gasoline than diesel.

Distillate fuels
This category covers a wide range of products. These oils are extracted mainly from the lowest fraction of crude oil distillation. They include diesel oil for use in diesel engines, light heating oil and heavy gasoils, which can be used as a feedstock in petrochemicals plants. Diesel oil is distilled at around 180-380°C.
Residual fuel oils: Sometimes known as heavy fuel oils, these are extracted from what is left after the distillate oils and lighter hydrocarbons have been distilled in the refinery. They include oils suitable for powering some types of ships, power plants and heating equipment, as well as for use in various other industrial purposes.

Still gas: also known as refinery gas, this is a gas, or mixture of gases (methane, ethane and ethylene, for example), produced as a by-product of upgrading heavy petroleum fractions to more valuable, lighter products through distillation, cracking and other methods. It can be used as a refinery fuel or petrochemicals feedstock.

Liquefied refinery gas: this is fractionated from refinery or still gases and kept liquid through compression and/or refrigeration. These gases can include ethane, propane, butane, isobutane and their various derivatives.

Liquefied petroleum gas (LPG): is a type of refinery gas, mainly comprising propane or butane. LPG can be used to run vehicles such as lorries and buses, and for domestic cooking and heating in remote areas that lack alternative fuel sources, or, indeed, on camping expeditions.

Propane: an odourless, easily liquefied, gaseous hydrocarbon, which is the third member of the paraffin series, along with methane and ethane. It can be separated from light crude oil and natural gas in the refinery. It is available commercially in liquefied form, and is used to power a range of items, such as barbecues, welding torches and some vehicles. It is also a major component of LPG.

Petroleum coke
A black solid residue used as a feedstock in coke ovens for the steel industry, for heating, chemicals production and for other purposes. It has a high carbon content — around 90-95% — and a low ash content, so it burns well. However, it has a high sulphur content, which can create environmental problems. It is obtained by cracking and carbonising petroleum-derived feedstocks, vacuum bottoms (the heavier material produced in vacuum distillation), tar and pitches using processes such as delayed coking and fluid coking.

Asphalt and road oil
Also known as bitumen in some regions, asphalt is best known as a road-surfacing material. A sticky semi-solid, it can be found in naturally occurring deposits, but it can also be derived from crude oil, by separation through fractional distillation, usually in a vacuum. It can be made harder by reacting it with oxygen. Road oil is any heavy petroleum oil used as a surface treatment on roads.

Petrochemicals feedstocks
Any inputs — such as naphtha — derived from petroleum and natural gas that can be used to produce chemicals, plastics, synthetic rubber and so on in a petrochemicals plant. © BASF
Carbon capture: explained

It’s economically and technically speculative, but CCS could be a bridge to a low-carbon future

Fossil fuels are set to remain a large part of the world’s energy mix for the foreseeable future, so the hunt is on for the best way to carry on using them while drastically cutting the amount of carbon dioxide (CO₂) pumped into the atmosphere.

A technology called carbon capture and storage (CCS) is among the most promising low-carbon solutions; it involves extracting CO₂ from power plants, factories and other industrial facilities before it is expelled into the atmosphere. The captured gas is then injected into a secure underground storage site — and removed from the climate-change equation (see box).

It’s the key to the sustainable long-term use of fossil fuels — helping mitigate the effects of climate change while renewable energy systems are developed. As such it’s an “airbag” technology, says George Peridas, a climate scientist at the Natural Resources Defense Council (NRDC), a US-based environmental non-governmental organisation.

How effective an airbag could it be? The International Energy Agency (IEA), a multi-

Capturing CO₂: the key to clean coal

CO₂ can be captured before or after coal is burned. In post-combustion capture, the CO₂ is stripped out of a power plant’s exhaust gases with a solvent such as amine or ammonia. Post-combustion technologies can be added — retrofitted — to existing pulverised-coal power plants.

Pre-combustion carbon-capture technology can be used in the new wave of integrated-gasification combined-cycle (IGCC) plants. Here, instead of being directly combusted, the fossil fuel is gasified to produce a synthetic gas (syngas) — a mixture of hydrogen and carbon monoxide (CO). The syngas is then processed in a water-gas-shift reactor, which converts the CO to CO₂ and more hydrogen. The CO₂ is then captured, leaving a hydrogen-rich syngas that can be combusted to generate electricity.

IGCC plants are more expensive to build than conventional coal-fired plants and the high hydrogen content of the fuel gas (over 90%) makes them less efficient than steam-driven plants. However, they come into their own once CCS is factored in, as the CO₂ they produce is in a high pressure, concentrated form that is relatively easy to capture — and that means big cost savings compared with post-combustion CCS technology.

In another variation, called oxy-combustion, fossil fuels are burned in nearly pure oxygen rather than in air. This produces a nitrogen-free flue gas that has water vapour and CO₂ as its main components. Although using oxygen increases costs, the highly concentrated stream of CO₂ that results from the process again makes capture relatively straightforward.

Leaders in IGCC technology, such as US company GE Energy, say the cost savings at the carbon-capture stage make IGCC the way forward, but there is still much debate over the pros and cons. One certainty is that post-combustion CCS technology will continue to play a significant role in the power industry for decades to come.

That’s because you can’t retrofit conventional pulverised coal power plants with IGCC technology and not only do most existing plants use conventional technology, but many new facilities in countries such as China — which has been opening more than one new coal plant a week on average recently — use it as well.

So if we are to tackle CO₂ emissions through carbon-capture technology successfully, a multi-pronged approach will be needed.
Profile — Mark Nesbitt

Name: Mark Nesbitt
Company: BP
Present job: Process engineer
Age: 27
Nationality: British
Degree: Queen's University Belfast, Masters in chemical engineering

Before I joined BP, in 2005, I’d already spent a year with the company — on an internship programme, between my third and fourth years at university. I worked at the Grangemouth terminal in Scotland that processes oil from North Sea fields, stabilising it for onward transport to refineries. It was a steep learning curve, but a great opportunity to take what I’d learned in the academic world and apply it on a practical scale.

That experience helped enormously when I joined BP’s training programme for new graduate recruits in the Exploration & Production business (E&P) — Challenge.

My first role at BP was in the E&P technology group at BP’s offices in Sunbury as a facilities engineer, providing technical support to business units around the world — helping select development concepts for projects and preparing feasibility studies for prospective projects, for example. I provided technical support on the business case for investments in Libya, which the company has since followed through, which is satisfying.

I then worked as a commissioning engineer on Greater Plutonio, a $5 billion, five-field development in deep Angolan waters. Initially, I spent time in South Korea, helping oversee the completion of the giant floating, production, storage and offloading (FPSO) vessel that is now producing oil from those fields. Then I worked in a rotational role offshore, until the start-up of the facilities; I was tasked with ensuring vital parts of the facilities were commissioned to the required standard. I won’t forget the day we commissioned the first well — seeing equipment I’d worked on processing first fluids from the Plutonio reservoir was immensely rewarding.

Recently, I have moved into a joint venture — in Amenas, a big gas project in Algeria in partnership with Norwegian oil company StatoilHydro and Algerian gas company Sonatrach. It’s been interesting to be exposed to other companies’ ways of working.

Initially, I was based in Oslo, Norway, working in an engineering contractor’s office. Again, the responsibility was huge: sometimes I was the only BP representative, even though I’d only been with BP for short time. Since completing the Challenge scheme, I’ve stayed on at In Amenas, assuming responsibility for all aspects of process engineering on a new gas compression project. I want to see the project right through the design and build phases to production. The whole process could take several years and will involve working in the UK and on-site in Algeria; but it’s not often you get the chance to see a project through all the cycles. And, if I stick with it, I could become the lead start-up engineer, which would be a great opportunity. In the long term, I see myself in engineering management for big projects in the E&P business.

Variety is one of the things that makes the job so interesting: one day you can be working with a deckhand offshore and the next you can be presenting to senior management in head office. There’s enough diversity in the energy business to satisfy anyone’s ambition: if one role isn’t to your liking there’s the flexibility to move into many different disciplines. But you need to be flexible too — prepared to travel widely and enjoy interacting with people from different cultures. If you are adaptable and open-minded, the industry offers great opportunities.
government think tank, says CCS could provide a fifth of the greenhouse-gas emissions cuts the world needs to make by 2050. However, the snag is that, unlike many other methods of cutting CO₂ emissions — renewables, nuclear power and greater energy efficiency — the idea remains untested at a commercial scale. Demonstration projects are urgently needed to show that the technology can operate safely and economically. The EU’s Zero Emission Fossil Fuel Power Plants (ZEP) programme, for example, wants to have 10-12 demonstration projects up and running by 2015.

The problem of price
But therein lies another problem: the plants are very expensive to build. According to Hydrogen Energy, a joint venture of BP and Rio Tinto, it costs $1.5-2.0 billion to build a large power station with the equipment and infrastructure needed to capture the CO₂, transport it and bury it underground. Energy companies don’t have that kind of capital knocking around. Even if they did, no sensible chief executive would invest in something as economically and technically speculative as CCS, at present.

The energy industry is well positioned to play a central role in developing the necessary technology, not only because the sustainability of its own operations is likely to rely on the deployment of CCS, but also because of its expert knowledge of areas such as reservoir and pipeline management. However, the financial impetus must come from governments — at least until CCS is an established business with predictable streams of revenue and profit.

When that happens, companies will be queuing up to invest: according to Gardiner Hill, head of CCS at BP, the CCS industry could be handling the equivalent of 120 million barrels of CO₂ a day by 2050 — half as
big again as today’s oil industry. If a high enough economic value can be attached to decarbonising energy supply, you don’t have to be Warren Buffett to work out that this could be big business.

But how do you assign a value to low-carbon energy that is high enough to get the necessary finance flowing? One option is to tax carbon emissions: that’s worked at the North Sea’s Sleipner West gas field. For over a decade, Norwegian energy company Statoil has been removing CO₂ produced with natural gas from the Sleipner field and reinjecting it into an aquifer more than 800 metres below the seabed because that is cheaper than releasing the CO₂ into the air and paying the taxes that this would incur.

**Cap and trade**

Another approach, being favoured by many governments around the world, is to create a marketplace in which carbon allowances — essentially the right to pollute the atmosphere with CO₂ — can be bought and sold. Known as cap-and-trade schemes, the higher the price of the carbon allowances goes, the more expensive it becomes to pollute and the more profitable it gets to introduce pollution-saving technologies and equipment (see p111).

Another way of incentivising investments in CCS — and indeed other, expensive low-carbon energy systems, such as solar power — would be to provide subsidies from public funds. Yet another would be simply to ban power plants that aren’t equipped to capture and store CO₂.

Why power plants? Because they’re the best place to start fighting climate change. The power sector accounts for around 33% of greenhouse-gas emissions and 45% of CO₂ emissions, says World Resources Institute, an environmental think tank. And over 40% of energy-related CO₂ emissions come from coal, according to the IEA. That’s because coal, when burned, produces twice as much CO₂ as natural gas.

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**Beyond carbon capture**

Carbon capture and storage (CCS) is not the only way of cleaning up the coal industry. New clean coal-burning technologies — some of which can be applied not only to new capacity, but also to some existing plants as they are upgraded — can cut coal’s environmental footprint significantly. Part of the solution lies in improving thermal efficiency, so enabling plants to generate more power from less feedstock.

Germany’s Siemens, for example, is planning to build what it calls the world’s “most efficient coal-fired power plant”, for power company E.On in Wilhelmshaven, Germany. The plant, which could be up and running as early as 2014, will operate at a steam temperature of 700°C, compared with today’s maximum of 600°C, giving it an efficiency rating of more than 50%, says Siemens. That improved efficiency should translate into 40% less coal being used than in a typical coal plant — and 40% less CO₂ being emitted.

Another idea is to mill renewable biomass, such as forestry residues and leftovers from agricultural products, into a powder and mix it with the pulverised coal before combustion — a process known as co-firing. The UK’s Drax power station is developing what it claims will be the world’s largest biomass co-firing project of its type: scheduled for completion in the first half of 2010, the facility will boost the plant’s co-firing capacity to 500 megawatts of power and cut emissions from the North Yorkshire power plant, which has a total capacity of 4 gigawatts, by over 2.5 million tonnes a year. That, it says, is equivalent to the CO₂ saving that would be achieved by generating power from 600 wind turbines.

Carbon-efficient fossil-fuel technologies are applicable elsewhere, too. US oil company ExxonMobil, for example, has adapted a combined heat and power technology called co-generation for use at some of its refineries — reducing its own energy bills and cutting CO₂ emissions from its plants. ☀
The other reason to tackle power plants and industrial facilities first is that a large amount of CO₂ is being emitted from a single point, so there's more to capture from one place. A power station called Drax is the UK's biggest emitter of carbon emissions, with an output of 21 million tonnes a year of CO₂. That's equivalent to the CO₂ output from something like 6 million cars. But capturing CO₂ from a single, static point is obviously much easier than capturing it from 6 million mobile ones.

Could we just stop using coal? No: it is forecast to account for 8.67 trillion kilowatt hours of the power we generate globally in 2010 — that's 42% of total power production. In India, Germany and the US it accounts for around half of electricity generation. In China the figure is about 80%. Other fuel sources, such as oil, gas, nuclear and renewables, couldn't fill this sort of gap overnight. Besides, coal is relatively cheap, it is abundant in some of the world's most stable countries and it is generally easy for energy-deficient countries to buy — so it's economically and strategically attractive.

For the moment, we just can't do without it. And that reality won't change much for decades: 13.6 trillion kilowatt hours — or 43% — of our fast-rising energy requirements will still be met by coal by 2030, according to the US government's Energy Information Administration.

Unless greener coal technologies are deployed, either the world won't have the energy it needs or it could find itself facing an environmental catastrophe.

Going underground

Thankfully, greener technologies are being developed. Reducing coal plants' environmental footprint partly depends on finding more efficient ways of burning coal to reduce the amount of coal burned — and CO₂ emitted — per unit of energy generated. But taking coal and other fossil fuels to the next level of cleanliness will have to involve CCS.

There's good news on the technical side: the technologies that make up the various stages of CCS are already proved. CO₂ is

BP is working with Statoil and Algerian national oil company Sonatrach on a big CCS project linked to the In Salah gas development in the Algerian desert
already routinely stripped out from natural gas to improve the gas' heating value or to meet pipeline specifications. It's also captured from industrial facilities to supply the food industry. The oil industry, meanwhile, has a profound understanding of oil and gas reservoirs and other geological formations; in fact, CO₂ has been injected into oil reservoirs for decades to boost recovery of oil by flushing more of it out, notably in the US.

And even some of the infrastructure is in place: there are over 3,500 kilometres of pipelines transporting more than 40 million tonnes a year of CO₂ to support the US' enhanced oil-recovery business. And pipelines elsewhere that were formerly used to transport hydrocarbons from such reservoirs to refineries might be suitable for sending CO₂ the other way — back to empty reservoirs.

There's also plenty of space for storing the gas underground, which can be held in various geological formations (see box). BP — which is working with Statoil and Algerian national oil company Sonatrach on a big CCS project linked to the In Salah gas development in the Algerian desert — has estimated that old North Sea reservoirs could hold all the CO₂ produced by European power stations over the next 60 years; others say they could accommodate considerably more. Just the aquifer of which Sleipner West is a small part has a thickness of 250 metres and has the potential to hold 600 billion tonnes of CO₂. At present, Statoil is storing just 1 million tonnes a year there.

But what about leakage? If the CO₂ seeps back out into the atmosphere, then the benefits of storage would be lost. However, there can be few places better suited to storing CO₂ securely than the subterranean chambers that managed to hold oil and gas securely for millions of years until man removed it. No-one can say the CO₂ will never leak out into the atmosphere, but Statoil estimates its North Sea site is highly unlikely to leak for several hundred years, by which time the human race should have created other solutions to the CO₂ problem. The Intergovernmental Panel on Climate Change (IPCC), the main global forum for collating scientific advice on climate change, says tests so far indicate that more than 99% of CO₂ is likely to be retained in properly managed geological

WHERE CAN THE CO₂ GO?

There are three main types of geological storage. The most attractive are existing oil and gas fields: their ability to hold gas indefinitely is already proved, the geology of producing fields is well defined and companies have experience of re-injecting gas through enhanced oil-recovery operations. Re-injecting CO₂ can also defray the cost of CCS by boosting rates of recovery of oil and gas at mature oil fields.

The second category is geological traps that do not contain hydrocarbons, but have similar characteristics to oil or gas bearing structures, or coal seams. The third possibility is aquifers — deep saline reservoirs with no defined structural traps. Although less well understood than oil reservoirs, aquifers are an attractive long-term solution because of their large size.

CO₂ does not necessarily have to be stored underground. Alternatives under consideration include deep-ocean storage, in which CO₂ is dissolved into seawater. Mineral sequestration above ground is another possibility, with CO₂ exothermically reacted with natural minerals to form stable carbonates. Another possibility would be to capture CO₂ directly from the atmosphere with chemical solvents.
structures after 100 years and that it could potentially be held there for thousands of years with little of it escaping.

**Can we afford it?**

Not everyone sees CCS as an appropriate solution to global warming problems: plenty of people have questioned whether CCS on a scale able to tackle climate change is feasible, either technologically or financially. While storage is comparatively straightforward, the process of capture is complex and expensive. The IPCC estimated in a report on CCS in 2005 that building a power plant with carbon-capture technology would add 20-40% to the cost of electricity production. The good news is that the cost of this technology is likely to fall rapidly, as engineers understand more about it.

Even environmental organisations that would prefer to see fossil fuel use reduced dramatically admit that this is not a practical proposition in the short term and are backing the use of CCS technology. NRDC, for example, wants the White House to make the fitting of CCS technology to all new coal plants compulsory.

Some potential CCS investors are concerned that high-cost CCS projects — like other expensive, climate-oriented technologies — may become lesser priorities for governments grappling with the more immediate problem of stopping the economic rot caused by the credit crunch of 2008. But many involved in the green-energy business say CCS could help move economies out of trouble, generating jobs and economic growth. Says BP's Hill: “The financial crisis is minuscule compared with the long-term challenges of climate change. CO₂ stays in the atmosphere for 200-300 years.”

**Signs of serious action**

It is clear that governments are coming around to this view and are now taking the technology seriously as part of a basket of measures to limit global warming. President Barack Obama’s US administration has brought a greener hue to its policies than its predecessor. Australia and China — like the US, countries with huge coal reserves — have been pushing ahead with programmes to develop and implement CCS schemes with government backing, while the North Sea offers ample room to handle European CO₂.

The UK said in April 2009 that all new coal-fired power stations in England and Wales must include CCS demonstration on at least 300 megawatts of their capacity and that developers must agree to retrofit CCS across the whole plant once the technology is proved, if they are to get the go-ahead.

The UK’s first application of carbon capture at a commercial coal-fired power station became operational at the end of May 2009 at the Longannet power station in Fife, Scotland. The 1 megawatt test unit, developed by Aker Clean Carbon, is capable of processing 1,000 cubic metres an hour of exhaust gas, although the captured emis-
sions are then being released into the atmosphere at present. Operator Scottish Power — owned by Spain’s Iberdrola — hopes Longannet will be awarded up to £1 billion of government and EU-backed funding to develop one of four large-scale demonstration CCS plants the UK has pledged to build. If that happens, then CCS could be applied to 330 megawatts of Logannet’s total 2.3 gigawatt capacity by 2014, with the CO₂ being buried beneath the North Sea.

Meanwhile, the US government is reversing a decision made by its predecessor to halt a $1.8 billion CCS project called FutureGen and says it plans to build a National Carbon Capture Center to speed up technological development — the country is already home to the world’s first, large-scale, fully functioning CCS plant at Wilsonville, Alabama. In October, US energy secretary Steven Chu said the US could have 10-12 commercial CCS demonstration projects operational by 2016, in preparation for wider commercial deployment by 2019.

In Canada, Alberta province has allocated $2 billion for CCS projects. And in Australia, the development of CCS is now seen as essential if the country’s large coal industry is to clean up its act: the government recently said it would help fund between two and four new CCS-equipped 1 gigawatt coal-fired power plants, as well as creating a CCS research centre.

Governments must also make it easier to finance projects. Again there are causes for optimism. The parliament of the EU this year voted to include CCS in its Emissions Trading Scheme, providing an important stream of financing for the 10-12 demonstration plants the bloc wants to build. The allowances set aside for CCS were worth around €6-7 billion in total when the move was approved, although the ups and downs of the carbon market could substantially affect their value in the future.

But some think more could be done to accelerate the technology’s uptake. Those running the ZEP programme say it could take up to 10 years to construct a major CCS project under the existing system. That time needs to be shortened to help achieve the emissions cuts scientists say are needed in the time available (see p102).
Climate change: explained

Fighting global warming is going to cost us a lot of money. The International Energy Agency estimated in 2008 that it would cost $45 trillion to halve carbon emissions by 2050.

But the cost of doing nothing is likely to be even greater, both in terms of human suffering and financial cost. UK government adviser Lord Stern said in an influential report on climate change in 2006 that failure to take action could end up costing the world more than 20% of global GDP every year to fight famine, disease, rising sea levels and so forth. Given that global GDP totalled more than $55 trillion in 2007 alone, the cost of inaction — based on Stern’s estimate — would be much higher than the cost of taking preventative measures.

Stern has become no more optimistic: in 2009, he said his report had underestimated the rate of global warming and the situation was even more perilous than he had thought.

What’s the panic about?

The Earth’s climate changes all the time and was subject to extreme fluctuations long before man started pumping industrial gases into the atmosphere. What is different now is that the present period of global warming is widely believed to be at least partly caused by man, and that we can do something about it, if we act quickly enough.

In 1995, the International Panel on Climate Change (IPCC), a worldwide team of expert scientists, forecast that the average temperature around the world would getwarmer by 2012. The Kyoto Protocol also helped promote wider use of mechanisms such as cap-and-trade to incentivise industry to cut emissions (see p111).

Initially, some of the big developed economies — and CO2 emitters — such as the US and Australia refused to sign. Big developing-world emitters such as China and India were also not included. However, since then the world has become much more convinced of the need for concerted action; crucially, the US is now much more supportive than it has been in recent years. That has raised expectations that the next big climate conference, to held in Copenhagen at the end of 2009, will produce far-reaching results (see p40).

Everyone from individuals to big companies are being asked to play their part. The push is on to find sustainable power from clean renewable sources, lowering CO2 emissions from transportation (see p20), using less energy in power stations, refineries and petrochemicals complexes, and capturing and burying the CO2 that is produced (see p94).
rise by between 1°C and 3.5°C by 2100, if we carried on pumping greenhouse gases (GHGs) such as carbon dioxide (CO₂) into the atmosphere at the then prevailing rate. Since then, some scientists have said the impact could be even more pronounced — perhaps 5-10°C of warming over the next two centuries if we don’t move fast.

It might not sound like much, but 3.5°C refers to the average for the whole globe, day and night, pole to pole. It translates into much hotter weather in many parts of the world, which would trigger droughts, rising sea levels through melting of the ice caps and possible humanitarian catastrophe. It seems the effects are already being felt: 11 of the 12 hottest years on record occurred between 1995 and 2006, according to the IPCC’s Fourth Assessment Report.

Scientists say that to stem global warming, we need to act urgently. CO₂ stays in the atmosphere for 100 years or more, so we will be living with what we do now for a long time to come. That means that even if we want to limit the increase in global temperature to less than 5°C by 2100, we need to cut CO₂ emissions by perhaps three-quarters compared with the present level, according to some estimates.

**Man-made global warming**

Some of the residual gases from industrial processes that we pump into the atmosphere contribute to the greenhouse effect, which causes global temperatures to be warmer than they otherwise would be.

The greenhouse effect is caused by the ability of some gases and particles to trap within our planet’s atmosphere the radiation from the sun reflected back from the earth’s surface. This radiation is mainly at the infra-red end of the spectrum and is absorbed by, for example, water vapour, methane, CO₂, nitrous oxides from fertilisers, chlorofluorocarbons (CFCs) and ozone. This trapped radiation heats up the atmosphere and, consequently, the earth’s surface.

A GHG can be a good thing — up to a point. It makes the world warm enough to live in, but too much of the effect will also threaten our existence.

Methane from agriculture and landfills is the GHG we are responsible for that has made the most important impact on global warming so far, its atmospheric concentration having more than doubled since pre-industrial times. CFCs are even more potent GHGs than methane, but strong global action on reducing the use of these in everyday products in the latter part of the 20th century has reduced their global-warming impact.

In terms of the energy industry, CO₂ is the main GHG. There is over a third more of it than there was in pre-industrial times. Readings at the Mauna Loa observatory in Hawaii (where better to put an observatory?) show

**A 3.5°C rise translates into much hotter weather in many parts of the world, which would trigger droughts, rising sea levels and possible humanitarian catastrophe**

CO₂ levels in the atmosphere now stand at around 390 parts per million (ppm), the highest level for at least 650,000 years, according to the US National Oceanic and Atmospheric Administration (NOAA). Between 1970 and 2000, the concentration rose by around 1.5 ppm annually, before jumping to an average annual increase of around 2 ppm between 2000 and 2008, according to NOAA.

The greater the amount of CO₂ pumped into the atmosphere, the more average global temperatures are likely to rise, but it is not a straightforward link. For example, not all CO₂ stays in the atmosphere: the sea absorbs some of it as does vegetation — hence the worries about the rate we are cutting down CO₂-absorbing forests. Other factors also influence temperature, such as solar activity and the amount of dust in the atmosphere — from volcanoes for example.
Natural gas: explained

Next time you boil a pot of pasta spare a thought for the stuff that’s heating the water. If your hob lights up with a blue flame then you’re one of the many millions in advanced countries who rely on natural gas for the basics. You use an electric hob? Well, there’s a good chance that the electricity is generated in a natural-gas-fired power station.

As winter started to bite across eastern Europe earlier this year, the question of where the gas comes from suddenly became a political topic as hot as that pot on your stove.

For the best part of three freezing weeks in January 2009 the problem seemed insoluble. Russia, home to almost a third of the world’s natural gas reserves, and neighbouring Ukraine were bickering about gas prices again. Moscow said Ukraine was refusing to carry out its job of passing on Russian gas to customers in Europe and that the country owed Russia about $2 billion in back payments. Kiev said Russia had deliberately charged punitively high prices for the gas. Gas shortages

It was political and it got nasty — especially for anyone relying on the gas. Shortages quickly occurred in Poland, Hungary, Romania, Turkey, Greece and Macedonia; some countries, such as Slovakia, experienced major falls in energy supplies. Russia accounts for about a third of the European Union’s gas supply, so the conflict between the former Soviet states spread across the entire continent. Brussels, home of the European Union’s leading politicians and bureaucrats, begged both sides to compromise. Eventually they did.

By the time Moscow and Kiev had signed an agreement that enabled gas flows to resume, consumers across Europe had, once again, received a harsh reminder of just how heavily they depend on Russia to heat their pots of pasta, fire their power stations and factories, keep their economies ticking over and stay warm during the winter.

People in rich, developed nations tend to take their energy supply for granted. But unless you live in a country blessed with large reserves of oil and gas then you rely as much as the average eastern European on politics and politicians to keep the lights switched on.

In fact, you don’t just rely on politicians. You rely on an entire industry that is built on the task of putting oil and gas into pipelines and energy into your home. That might look simple on the surface: build a pipeline and fill it with gas. But financing and building pipelines is anything but easy — especially if they’re routed across the sea, traverse more than one country or pass through areas where sabotage might be a problem. Or if the costs run into the billions of dollars.

Even if the governments of the countries that will host the pipeline can agree on a route, studies must be carried out to show that the project will not damage the environ-

When do you find oil and when do you find gas?

The type of hydrocarbons that will be found — assuming they’re there at all — depends on pressure and temperature, which rise the deeper you go. Oil tends to be found within a certain temperature and pressure range — in which geologists refer to as the oil window. Typically, the oil window’s 65-150°C temperature range is found at depths of up to about 5 kilometres, although oil that’s formed at one depth can later migrate into shallower rocks or move closer to the surface because of erosion above it.

Natural gas tends to form at higher temperatures and, therefore, at greater depths.
Profile — Katherine Smith

Name: Katherine Smith
Company: Tenaris
Present job: Global trainee, process engineer
Age: 25
Nationality: American
Degree: Engineering management, Missouri University of Science and Technology

Tenaris, a leading supplier of tubular products and associated services to the oil and gas industry, hired me as a process engineer straight out of college. In 2008, I joined the Global Trainee Program for recent university graduates.

During my first year, I have travelled throughout Tenaris’ manufacturing network. I recently spent a month in Campana, Argentina, getting to know the main aspects of the company at the Induction Camp — a requirement for all new recruits. To continue my training, I will be transferred to our seamless-tubes plant in Veracruz, Mexico, in a couple months. Since that plant has been part of Tenaris for a long time, many of the problems I may face at facilities in the US have already been solved. Being exposed to those solutions will help me implement change here.

I am now based in a plant in Arkansas that manufactures welded pipes for drilling operations and for transporting oil and gas. The mill recently became part of Tenaris so we are still in a transitional phase. We have to go from a system that prioritises quantity to one focused on quality and safety. I’ve been given a role in some of our most important projects; the workload’s both challenging and demanding.

Helping manage the cultural shift from one system to another has been among the most interesting problems. How do you communicate the value of a new system to people accustomed to the old way? Add in language and cultural barriers and it becomes even more challenging.

Our main project is recording and analysing our data more effectively to create a more efficient and safer industrial system at our facility. I’m working on verifying that our pipes are being made exactly in accordance with our customers’ specifications.

The precision required to make a uniform section of pipe is incredible and requires high-tech equipment. Some of our facilities have developed amazing systems to track and catalogue everything produced.

In the US, we are introducing more sophisticated ways of weighing, controlling and stenciling our tubular products for tracking purposes. We’re continually upgrading the technology and we’ll gradually introduce those systems, capitalising on the accumulated know-how in the organisation.

Improving production processes serves a double purpose. It helps ensure the safety of our employees and guarantees we comply with our customers’ expectations for quality, reliable products, delivered on time.

The implementation of these processes, which is part of a co-ordinated effort carried out in Tenaris’ mills in more than 25 countries, will facilitate the entire supply chain process. Beyond the plant, there’s a massive, global network — trucks, trains, boats — to move materials from plant to plant and to customers. It’s a taxing logistics operation.

I’ve found that even in a big company, you can make a material difference, if you’re insightful and think creatively. You have to find the non-obvious stuff and gain acceptance.

Personally, I am interested in finding ways to make the plant more energy efficient. For a company to be successful, it must be dedicated to sustainable development.
ment. Both steps take time — usually more than consumers would like. And the banks and governments that will stump up cash to pay for them want to see guaranteed markets and supplies in the form of long-term contracts. This takes years too.

Iran, with the world’s second-largest natural gas reserves after Russia (see p128), has been trying to build a pipeline to India and Pakistan for years — but no-one is throwing cash yet at a project that would require two of the world’s long-standing political antagonists to set aside their disagreements.

There are some fundamental reasons why natural gas has been a flashpoint recently. We all know about the surge — and then crash — in oil prices in recent years. But even when oil prices were flying through the roof in mid-2008, hitting almost $150 a barrel, gasoline and other oil products were still flowing freely to consumers. Even if it cost more, you could still fill up your car.

That’s because the oil market is liquid. That’s not a pun, it’s a term economists use to describe a market place where a commodity is traded by lots of people. Sure, prices go up and down, but there was still oil to trade. The oil market is global, too. Consumer countries buy oil from across the world. Producers take it out of the ground and send it down a pipeline to a port, and once the crude is loaded onto a boat it can travel to whichever buyer pays the most.

**Oil’s troublesome little sister**

Natural gas, by comparison, is oil’s troublesome little sister. In fact, not long ago oil explorers who found gas in a well considered their discovery a let-down. In the bad old days, much associated gas — gas found alongside oil in a reservoir — was simply burned away, with adverse environmental consequences. Making use of the gas would have required a whole different kind of expensive infrastructure. And then the companies would also need to line up customers.

Not so now. Gas burns more cleanly than oil, making it a vital source of energy in a
6.5 — Understanding oil and gas

To liquefy or not to liquefy?

Like oil, natural gas is often found in some of the world’s remotest regions. Russia, for example, wants to develop a gas field called Shtokman; it’s in the Barents Sea, well north of Russia’s landmass and close to the Arctic. For most of the year, it is under ice.

One solution for getting those kinds of reserves to market is to liquefy it close to the gas field and export the liquefied natural gas (LNG) by tanker. That involves cooling the gas to -162°C. LNG is the fastest-growing segment of the natural gas market. But it’s costly. Some of the LNG projects being developed on the northwest coast of Australia, a burgeoning exporter, cost upwards of $15 billion.

LNG accounted for about 7% of total gas demand last year, according to Wood Mackenzie, an energy consultancy. But this will grow rapidly, because LNG has advantages that pipelines lack.

For example, many consumer countries see LNG as a way to reduce their reliance on piped gas. Gas through pipelines exposes consumers to the kind of problems that eastern Europeans faced last winter — when the supplier can’t ship his product, the pipelines can stand empty. If an LNG supplier fails to deliver, another one can be found to fill the gap.

More liquid

The LNG market is beginning to operate as a liquid market too. In theory, that should result in the most favourable price for consumers.

Lots of the LNG produced in countries such as Qatar, the world’s LNG powerhouse, is contracted on a long-term basis. But already, says Wood Mackenzie, 15-20% of LNG is traded on the spot market, where buyers can purchase short-term cargoes as and when they need them.

Pipelines are still vital. In the UK, for instance, the North Sea has long been the main source of natural gas, all of it supplied through pipelines. And, when it has needed extra gas, there are pipelines that cross the English Channel, tapping continental supplies.

The North Sea’s production is declining, however, and UK gas consumption continues to grow. So LNG terminals are sprouting up along the country’s shoreline. That’s crucial: any consumer nation that wants to take advantage of LNG’s flexibility needs a sophisticated infrastructure to receive the tankers that carry it — and then the facilities to regasify the liquid gas and deposit it in the local pipeline grid. It also needs deep-water ports able to handle the LNG tankers — enormous cryogenic ships that can carry up to 260,000 cubic metres of gas, and stretch almost 350 metres in length.

A commodity for the world

Piped gas is a commodity for regions, but LNG is one for the world. That is transforming the gas business — and the energy outlook for many countries that depend on imports. China, the world’s fastest-growing energy consumer, now sees LNG as critical to its ability to keep supplying the economic powerhouses along its coastline — cities such as Shanghai and Guangzhou — with energy.

There are other uses for gas reserves that once seemed stranded in inaccessible locations. Gas-to-liquids (GTL) technology involves converting natural gas into ultra-clean liquid products, such as synthetic diesel and naphtha, which are traditionally produced by refining crude oil. Qatar, home of the world’s largest gas field, is leading the way with this technology, as it has with LNG. So far, GTL production is small and, to some eyes, the whole process looks costly and fiddly, given that established infrastructure allows oil to do the same thing.

But, then again, there was a time when people thought natural gas would never be much use for anything. Your boiling pasta pan suggests otherwise.
world where consumers are concerned about pollution and global warming. And building gas-fired power stations is fairly cheap.

Those reasons, combined with the world’s abundant reserves of gas, have made it a fuel of choice for many advanced economies. The downside is that getting gas to a market can be a heinously complex business.

In the gas world, everything hinges on infrastructure. The problems between Russian and Ukraine last winter stemmed from the Soviet era, when Moscow sketched out the routes for the USSR’s gas exports to the West. The most important pipeline goes through Ukraine. And once the Soviet bloc disintegrated, Moscow’s control over that infrastructure grew weak.

Most of the world’s gas is shipped from producer to consumer by pipeline. Consumers pay producers for the gas, and the molecules magically appear at the other end of the pipeline. Usually, the seller wants to lock the consumer into a long-term agreement to buy the gas. These contracts often last for up to 20 years or more and commit the buyer to a given price, even if for some unforeseen reason he doesn’t need the gas.

Politically complicated

Things grow more complicated, politically, when third parties get involved. Transit countries — between the producer and his market, which receive a fee for allowing the pipeline to cross their territory — can be the bane of producers and, sometimes, consumers.

After its experiences with Ukraine in recent years, for example, Russia is keen to build pipelines that link its borders directly to the EU, its main customer. It has two pipelines in the works. One, Nord Stream, will go under the Baltic Sea to Germany and the other, South Stream, will go under the acidic waters of the Black Sea, at a depth of up to 3,000 metres, and land in the Balkans. Both pipelines avoid Ukraine.

Meanwhile, the European Union is tired of what seems to be an annual dust-up between Kiev and Moscow. So, in addition to the two new pipelines Russia plans, Brussels also wants at least one more pipeline to supply eastern Europe with gas from Central Asia, another region rich in reserves.

To understand the geopolitical chess game of gas supplies, it’s easiest to look at a map (see p106). Consider the European Union’s dilemma: to diversify its sources of natural gas, it wants to import it all the way from Azerbaijan, Iran, Egypt, Iraq and even Turkmenistan through a proposed pipeline called Nabucco. It is one of the most ambitious infrastructure projects ever considered. Linking Turkmenistan with central Europe, for example, would require a pipeline under the Caspian Sea to Azerbaijan, then the transit of the gas through the Caucasus, Turkey, up through the Balkans and into Austria. And that doesn’t include the spur lines that would allow Iranian, Iraqi, or Egyptian gas to feed into the system.

OMV, the Austrian firm that leads a group of companies planning the Nabucco pipeline, says it could cost around €8bn, although many analysts expect it would be much more expensive. At the same time, consider the challenge of getting all of those countries to agree even a timetable to begin building the infrastructure.

That and the Iran-Pakistan-India venture are the most political pipeline projects around. But politics isn’t the only problem producers face when they want to deliver their gas to market.
Name: Mario Sobacchi  
Company: Eni  
Present job: Project manager  
Age: 31  
Nationality: Italian  
Degree: Degree in engineering, Politecnico di Milano; MSc in mechanical engineering, University of Illinois, Chicago

Since joining Eni — after graduating in 2002 — the job has exceeded my expectations: the variety of activities, the different locations I’ve worked in, the diversity of people I have teamed up with have given me a wide range of valuable professional experience.

I started in the engineering department of Eni Exploration & Production in Milan as a process engineer. I moved to a project-engineering position two years later, co-ordinating a range of engineering disciplines on various upstream projects, mainly related to gas production and flaring in Nigeria. Although still based in Milan, I often travelled to project sites, spending about half of my time in west Africa. I also travelled more widely, working with several different divisions of the company across the world — in Pakistan, Indonesia, Russia and elsewhere.

In 2006, I was given a managerial role in Eni’s research and development (R&D) department, co-ordinating R&D activities relating to surface-production facilities. It was a very interesting experience — one that helped me understand the biggest technological challenges facing the oil and gas industry and gave me valuable insights into the types of solutions that might work.

But although there are many exciting and creative ideas out there, there’s a long way to go. The industry is having to develop resources in increasingly difficult conditions — coping with deep waters, sour fluids, remote locations and heavier oils, for example. We must extract the greatest possible value by, for example, maximising recovery factors, developing new products and reaching new markets. That’s what makes R&D an essential investment for a major oil company.

Last year, I moved to Eni Venezuela as a project manager. My role involves identifying the best development scheme for a heavy-oil block in the Orinoco oil belt. We’re setting up a joint venture with PdV, Venezuela’s state-owned oil company, to develop it and I’m providing technical support.

Finding the most economic ways of transforming the heavy oil we will be producing into marketable products requires careful co-ordination of a large number of professional functions; all components of the business chain — from reservoir exploitation to refining technologies, and from enhanced oil-recovery technologies, to market analysis and distribution to end users — must be thoroughly investigated and finely tuned.

The breadth and scope of this project is fascinating and careful planning is essential. In addition to the technical issues, we must take full account of the needs of local communities around the site and strict sustainability requirements, as well as complex legal, taxation and financial constraints and difficult negotiating conditions. Being exposed to the entire value chain of the industry is a unique learning opportunity — and one that should help me move forwards to business management and more senior positions.

The oil and gas industry is complicated: it relies on teamwork. And it depends on motivated professionals all over the world getting to know and adapting to different cultures and ways of doing things. It supports people with a can-do attitude. It’s a business where people still make the difference. ✤
Cap-and-trade: explained

Governments generally claim to be in favour of fighting climate change, but are also reluctant to introduce emissions-regulations domestically if it puts their companies at a competitive disadvantage to rivals from countries with laxer emissions regulations.

What’s needed is a global system that rewards reductions in carbon emissions while penalising excess pollution, without making companies and countries feel they are putting themselves at a disadvantage. This, according to its backers, is where cap-and-trade comes in.

How does cap and trade work?

Cap-and-trade schemes aim to make it very expensive and undesirable for industries to produce more than a certain level of carbon — hence the “cap” — and to reward companies financially for developing greener projects. These two elements are closely linked by a mechanism involving the “trade” aspect.

Under a cap-and-trade scheme, polluting companies are issued with a certain amount of free, tradable credits — effectively emissions-cuts IOUs — each representing a set volume of carbon dioxide (CO₂) emissions and covering what the managers of the scheme deem to be an acceptable level of atmospheric emissions from the companies’ plants.

If a company exceeds the emissions limits covered by the credits allocated to its plant then it must either reduce its emissions or buy more credits from another company that has some spare ones. Those sellers may have acquired their surplus credits by making their plants cleaner, so that they produce fewer emissions than are covered by the number of free credits issued to them.

Effectively, the big polluter in this case is paying someone else to make emissions cuts so it doesn’t have to. But as long as the caps are set at a low enough level, the effect should be to lower overall CO₂ levels in the atmosphere. The scarcer the tradable credits, the higher the price of carbon and the more prohibitive the cost incurred from producing it: a sufficiently robust price signal should then encourage investment in low-carbon technologies.

The EU Emissions Trading Scheme covers more than 10,000 installations in the energy and industrial sectors, collectively responsible for nearly half of the EU’s CO₂ emissions and 40% of its total greenhouse-gas emissions.
This type of scheme can be applied not just within one country, but over a larger region, or even — potentially — the world. It still relies on co-operation between as many nations as possible if it is to work properly, but cap-and-trade supporters say such a scheme is the easiest route towards such co-operation.

Who is doing it?
So far, cap-and-trade is in the relatively early stages of development and is mostly being adopted by the world’s long-standing industrial powers.

The EU is ahead of the field. The EU Emissions Trading Scheme (ETS) was launched in January 2005 and has gradually increased its scope through successive phases, each introducing tougher caps and covering more sectors and companies than before. At present, the ETS covers more than 10,000 installations in the energy and industrial sectors, collectively responsible for nearly half of the EU’s CO₂ emissions and 40% of its total greenhouse-gas emissions, according to the European Commission. Phase three of the ETS is due to be introduced in 2013 and will run

CDM projects
A particularly thorny issue for the architects of global emissions legislation is the participation of developing countries in cap-and-trade, or indeed any tough action on carbon emissions. Developing countries argue that their economic progress would be held back by the need to adopt expensive green measures and that developed countries — which are largely responsible for manmade climate change — should shoulder most of the burden.

The trouble is that the biggest of the developing world countries, including China, India and Brazil, are responsible for a growing proportion of today’s CO₂ emissions. The US Energy Information Administration estimates that energy consumption will be around 73% greater in the developing world — non-OECD (Organisation for Economic Co-operation and Development) countries — in 2030 than it was in 2006, but only 15% higher in the industrialised world — OECD countries. That suggests the failure of emerging markets to participate in cap-and-trade would make the system much less effective. So can cap-and-trade be adapted to make it more palatable to developing countries, even if they don’t participate fully now?

One solution being tried is the use of schemes such as the UN-managed Clean Development Mechanism (CDM), set up under the Kyoto Protocol. This enables firms from the industrialised world to generate credits by building green projects in developing countries. Those credits can then be used in, for example, the EU’s ETS, to offset the cost of carbon emissions produced by those companies at home. CDM projects are becoming increasingly widespread. A carbon-capture project in China could be eligible, as might a solar-energy project in the Middle East or a reforestation programme in Africa — anything that can be shown to reduce the amount of CO₂ going into the atmosphere.

But they remain controversial. One argument against CDM projects is that they do not encourage Western firms to make big emissions cuts at home, if they can do so — usually more cheaply — in the developing world. In other words, the resulting cuts may be “instead of”, rather than "as well as", cuts in the industrialised world.

Another issue is that the CDM encourages developing countries to rely on Western firms to create green projects on their soil, rather than doing it themselves. And then there is the tricky concept of “additionality”, which CDM projects are supposed to embrace. This means a project that earns CDM credits is supposed to be one that would not have gone ahead anyway without that incentive — and that can be a very hard thing to prove.
to 2020, by which time the EU aims to have achieved emissions cuts of 20%, compared with the 1990 level.

The credits traded are known as “allowance” units, each representing a tonne of CO₂. The sheer number of credits generated by the EU ETS means the most straightforward way to trade them is to set up big exchanges as intermediaries, much like stock and bond markets. Trading on these exchanges determines the price at which allowances change hands. The biggest established so far is London’s European Climate Exchange (ECX).

Several other nations have their own schemes in development. Australia — one of the world’s largest CO₂ emitters per capita because of its high reliance on coal for power generation — hopes to introduce its own trading scheme in the next few years, for example. But the big prize for cap-and-trade proponents would be to get the world’s largest economy, the US, on board.

**Going it alone**

The reluctance of the government of George W Bush to adopt emissions-cutting policies prompted several states to attempt to go it alone. California — one of the world’s top-10 economies on its own — together with six other US states and four Canadian provinces decided in 2008 to set up their own trading scheme. However, it may no longer be necessary: President Barack Obama, who is supportive of climate-change measures, wants to introduce a US-wide scheme, similar to the EU ETS.

These national and regional initiatives, and others that will follow, are all well and good, but unless the countries involved cooperate by merging their schemes or making the credits from one tradable in the others, emissions trading is unlikely to maximise its potential. International negotiators are putting a lot of effort into resolving how this can be done, ahead of the Copenhagen climate change summit in late 2009, where emissions trading will be one of the hottest topics.

Already, one of the main problems for regulators is deciding how to calculate emissions from movable sources, such as planes.
Biofuels: explained

With the world’s largest economies pushing increased usage, biofuels are here to stay

The internal combustion engine is a part of virtually everybody’s life — like it or not, it’s here for the foreseeable future (see p20). But we need to cut down on the amount of harmful carbon emissions it produces.

That’s where biofuels come in: they offer the prospect of reductions in carbon emissions without the need to replace or radically alter existing transportation infrastructure. Hydrogen and electricity are interesting alternatives for powering vehicles, but they require a complete redesign of the way vehicles work and can’t be used with existing cars, whereas biofuels can.

Biofuels are created by processing vegetation high in sugars or vegetable oil into bioethanol and biodiesel. These can be blended with, or even used instead of, conventional gasoline and diesel — and they produce much less pollution when burned than conventional refinery fuels.

In the EU, one of the world’s biggest vehicle markets, nations are being asked to raise the amount of renewable energy — mainly biofuels — used for transport to 10% of total fuel consumption by 2020, compared with an average of well under 5% now. That’s a significant increase. Similar measures are being implemented, or targeted, around the world; this will require billions of dollars in financial incentives, but proponents believe the environmental benefits will be worth all the effort and money.

The biofuels industry is already well established in the major economies. The US, the world’s biggest biofuels manufacturer, produces bioethanol from maize (known locally as corn) cultivated across the Midwest. Germany produces biodiesel from rape-seed, among other feedstocks. Brazil, the world’s biggest ethanol exporter, pioneered the production of ethanol from sugar cane, taking full advantage of its ample land resources and sub-tropical climate; it has also developed flexible-use, or flex-fuel, cars that can run on any ratio of gasoline and biofuels. China, India and other fast-developing economies in the Asia-Pacific region are also turning to biofuels as part of their efforts to find viable new transport fuels.

According to the US Department of Energy, total annual biofuels production across the world could increase more than sixfold by 2030, from 12 billion US gallons in 2005 to 83 billion US gallons in two decades’ time.

Fuelling change?

Exactly what form biofuels in use in a decade’s time will take remains to be seen, but a big change seems to be in the offing. The main biofuels on the market today — so-called first-generation biofuels — are bioethanol and biodiesel, which can be made from a variety of raw materials, but are generally derived from crops such as maize, sugar cane, palm oil and rapeseed. However, there are doubts over whether they make a positive contribution to the environment: in
some cases, carbon savings made by burning clean biofuels in motor vehicles can be outweighed by the carbon dioxide (CO₂) that is emitted during the cultivation of the crops, their conversion into fuels and their transportation to market.

Biofuels present another significant risk: by occupying land that could be used to grow food crops, the cultivation of crops for fuels could lead to food shortages and inflation in food prices.

However, the commercialisation of second-generation biofuels technologies — biomass-to-liquids and cellulosic ethanol, for example — could assuage many of these worries. These emerging technologies enable biofuels to be manufactured from a much wider range of raw materials, including agricultural by-products, such as plant husks and inedible maize stalk and grasses, which are easy to grow and can’t be eaten. Even algae can be used to produce biofuels (see p78). This should improve production efficiency and reduce carbon emissions per unit burned. It also ought to ease competition with the food industry because some second-generation biofuels crops can be grown on marginal land that is unsuitable for cultivating food crops.

Much scientific work remains to be done to perfect these technologies, but the backing they are receiving in high places suggests they have a bright future. The US already requires a minimum amount of bioethanol to be blended into gasoline and has set a target of using 36 billion US gallons of biofuel a year by 2022. And, in May 2009, US president Barack Obama’s government upped the ante, with plans to spend $1.8 billion on developing second-generation biofuels.

### Biofuels: key concepts

**Bioethanol:** also known simply as ethanol (ethyl alcohol), this is the most widely produced biofuel. It is usually created by fermenting starch or sugar crops, including maize (corn), sugar beet and sugar cane. Bioethanol is often blended with gasoline to fuel cars. In some cases, it can completely replace gasoline as a fuel.

**Biodiesel:** a combustible fuel that can be mixed with mineral diesel. Derived from fatty-acid alkyl esters, biodiesel can be made from a wide variety of feedstocks, such as rapeseed and soybean oils.

**Biomass:** in the context of the fuel sector, any vegetation whose energy can be harnessed in fuel.

**Biomass-to-liquids (BTL):** a combustion, rather than fermentation, process, in which biomass is converted into synthetised gas, or syngas, and then put through reactions with other compounds to produce a variety of end-products, including diesel and ethanol. BTL products are made using Fischer-Tropsch technology, which has been developed in another area of the energy industry, the gas-to-liquids sector.

**Cellulosic fermentation:** most fermentation processes could be called cellulosic, as the word just refers to breaking down lignocellulose in plant matter. However, in the biofuels industry, it normally signifies the ability to break down a much greater amount of plant matter than has been possible on a commercial scale to date. The end result is the same, though — bioethanol, for example.

**Jatropha:** a plant indigenous to Central America that produces oil suitable for conversion to biodiesel. It has attracted much interest because it grows well on marginal land across tropical and subtropical areas, in places such as India and Africa. This reduces the pressure on land needed for food crops, although it remains to be seen whether jatropha’s much-touted potential can be converted into commercial success.
The US Environmental Protection Agency estimates that bioethanol use in the US reduces CO\textsubscript{2} emissions by around 16% compared with using just conventional gasoline. Now it wants to see a 20% reduction in greenhouse-gas emissions from renewable fuels produced in new facilities, 50% lower emissions for biomass-based diesel and advanced biofuels and a 60% cut from cellulosic biofuels.

**Industry leaders**

Oil companies are eager to play a role in helping to achieve such goals. Most of the big oil firms were among the pioneers of bioethanol and biodiesel, and have successfully integrated biofuels into their supply chains. Given their growing familiarity with the biofuels business and their history of technological innovation, their focus is now switching to developing the technology for second-generation biofuels.

BP, for example, has several biofuels projects on the go, including a partnership with chemicals giant DuPont to develop biobutanol, an ethanol-based product with a much higher energy content than the bioethanol in use at present. It can also be made from next-generation feedstocks, including grasses and stalks. BP has also invested in jatropha, an inedible, oil-producing crop that grows on marginal land and from which biodiesel can be derived, through a joint venture with UK firm D1 Oils.

Shell, meanwhile, is developing new biofuels-to-liquids (BTL) technologies through an investment in Choren Industries, a German company that has built the world’s first commercial BTL plant, in Freiberg.

US ethanol producer Poet is another pioneer, developing cellulosic processing of maize in an effort to make greater use of all parts of the plant in the production of biofuels — not just the edible bits. In January 2009, it opened an $8 million pilot plant in South Dakota that runs on corn cobs and other crop residue. The 20,000 US gallons a year facility is a precursor to a $200 million, 125 million US gallons a year commercial-scale cellulosic plant being built in Emmetsburg, Iowa, and scheduled for start-up in 2011.
Gasoline: packing a punch

Note: values are approximate and may vary
Sources — National Physics Laboratory (Kaye & Laby online), FDDB.info
Grow your own (oil, that is)

Diesel, jet fuel and other useful liquid products don't just come from crude oil. Using some clever chemistry, they can be made from other hydrocarbons — coal, natural gas, biomass

If you’re worried about climate change, pollution or running out of oil, you’ll like the sound of this: fuel manufactured locally from renewable plants or waste that produces almost no greenhouse-gas (GHG) emissions and burns more cleanly and efficiently than today’s pump products.

It sounds too good to be true, but it’s possible; biomass — organic matter, from wood chip and stalks to chicken manure — can be converted into valuable fuels. How? By replicating the process that, over 400 million years, generated oil from organic matter — in the case of plants, by converting photosynthesis-derived chemical energy into hydrocarbons. But a few hundred million times faster.

The FT process

So-called biomass-to-liquids (BTL) technology is based on two main steps: first, the biomass is converted into a synthesis gas, consisting of hydrogen and carbon monoxide. Next, the Fischer Tropsch (FT) process uses chemical catalysts to convert that hydrogen and carbon monoxide mix into liquid hydrocarbons similar to the oil products produced by a conventional oil refinery. These liquid hydrocarbons are known as synthetic fuels.

When BTL products are burned in a car, they emit CO₂; but the cycle is, in theory, carbon neutral because the emitted CO₂ is absorbed by next year’s crop. If the trucks bringing the biomass to the processing unit ran on these green fuels and if the energy used to power the production facilities were derived from green sources, the process could be carbon neutral. German BTL firm Choren Industries, which has been operating a small pilot plant since 2003 and hopes to begin operating its first commercial unit in 2010, claims BTL could cut GHG emissions by up to 90% compared with conventional fuels. Widespread use of BTL would also mean countries could grow their own oil — preferable to relying on other countries to supply it.

It might sound revolutionary, but the FT process has been around for almost a century. It was invented in 1923 by a German chemist, Franz Fischer, and Czech-born Hans Tropsch, at Germany’s Kaiser Wilhelm Institute for Coal Research.

It hasn’t yet been applied to biomass on a commercial scale, because costs are too high and because there isn’t enough biomass available. But the FT process is being used commercially to make synthetic fuels from other hydrocarbons sources — natural gas and coal.

All three processes — BTL, gas-to-liquids (GTL) and coal-to-liquids (CTL) — yield identical end products. The big difference is

Salt and vinegar with your chips sir? Choren Industries claims BTL could cut GHG emissions by up to 90% compared with conventional fuels.
Flying with natural gas

In October 2009, Qatar Airways operated the world’s first commercial passenger flight using gas-to-liquids (GTL) jet fuel — from London to Doha.

GTL fuel is produced using the Fischer-Tropsch process, which involves a catalysed chemical reaction in which carbon monoxide and hydrogen are converted into liquid hydrocarbons (see p118).

On 1 February 2008, the Airbus A380 became the first commercial aircraft to fly with a synthetic liquid fuel, although that aircraft did not carry passengers. Airbus says GTL, at some locations, could be a practical alternative to conventional jet fuel.

Reflecting the growing importance of GTL, the World Petroleum Council (WPC) will dedicate part of its programme for the 20th World Petroleum Congress, in Doha in December 2011, to natural gas and GTL. Says WPC Director-General Pierce Riemer: “Qatar is proving that GTL will become a commercially viable, environmentally friendly fuel.”
how each feedstock is turned into a synthesis gas ready for FT catalysis. It might sound self-evident, but turning natural gas into a synthetic gas is relatively easy, because it’s already gaseous. Gasifying a lump of coal or a pile of woodchip is more difficult and — yes, you guessed it — more expensive. As a result, GTL is the most popular option.

The similarities with conventional refinery fuels are important: GTL products can be transported, distributed and marketed using the same infrastructure as refinery products. And car engines don’t need to be modified to use them. So they fit neatly into the existing supply chain.

But there are important differences, too: GTL fuels are cleaner than conventional refinery fuels. They are virtually free of sulphur, nitrogen and aromatics; as a result, they can reduce local pollution and improve air quality. (But unlike BTL, GTL wouldn’t result in a significant decline in CO₂ emissions compared with products made from crude oil).

GTL manufacturers say synthetic fuels have other advantages. With a cetane rating of 70 or more, compared with closer to 50 in the case of standard refinery diesel, GTL diesel can enhance engine performance. Audi and Shell demonstrated that to spectacular effect in 2006, when an Audi R10 TDI, running on a blend of GTL and normal diesel became the first diesel car to win the Le Mans 24-hour race. And it wasn’t a fluke: the team has since chalked up several more high-profile race victories.

Diesel is a big component of GTL, but the process makes other products too. Last year, for example, the Airbus A380 became the first commercial aircraft to fly with a synthetic liquid fuel processed from gas (see pxx). At some locations, GTL could be a practical alternative to conventional jet fuel, even in the short term, says Airbus.

Reduced reliance on oil

Another attraction of synthetic fuels that reducing reliance on crude oil by using other sources of energy to do the same job — gas, coal or biomass — is just good sense. Sometimes it’s a necessity: synthetic fuels produced from coal were used in Germany during the Second World War and in South Africa during apartheid. Both regimes had coal, a need for mobility, but not enough oil.

The US Air Force also sees strategic advantages in being able to use alternative fuels to oil, because oil is a commodity that the US needs to import in large quantities. Last
year, a B-1B Lancer became its first aircraft to fly at supersonic speed using an unconventional fuel — a 50:50 blend of synthetic fuel and petroleum gases. The Air Force wants to be producing at least half of its fuel from domestic resources by 2016. Those resources might include coal, which is abundant in the US. China, another oil-deficient economy that would also like to become more self-sufficient, also has large coal reserves and is developing CTL projects.

But despite these growing pockets of interest in the technology, CTL has failed to have much of an impact on the fuels market. There’s only one large CTL facility: Sasol’s 150,000 barrels a day (b/d) Secunda plant in South Africa. This is because oil products are widely available and much cheaper. CTL also produces a large amount of carbon and would only be feasible on a large scale if combined with carbon capture and storage technology. That would add significantly to costs.

GTL, however, is set for a rapid growth phase. The world’s first commercial GTL plant, Oryx GTL in Qatar, opened for business in 2006 and, after overcoming some technical problems, is close to its design capacity of 34,000 barrels a day. The next big project scheduled to enter service will take the GTL industry to a new level of scale: the Shell-operated Pearl project, also in Qatar, should start selling products in early 2011, adding 140,000 barrels a day to global capacity and roughly tripling world output to around 213,000 barrels a day. That’s rapid growth, no doubt about it, yet GTL will still be just a drop in the ocean of the 84 million or so barrels of oil consumed every day around the world.

There are several reasons why GTL is still a niche industry. To make a commercial success of GTL, the ideal ingredients are abundant natural gas reserves, low production costs for the gas and good port facilities, preferably within easy reach of a big oil market. Qatar’s North Field has those qualities, which is why the world’s main GTL projects are in Qatar. But there aren’t many other North Fields around.

If one of those ingredients is missing, there are alternatives to building an expensive FT refinery: liquefy the natural gas and ship it to market on liquefied natural gas (LNG) carriers or, if there’s a market within range, build a pipeline. One of those two options will often be cheaper and more profitable than GTL.

And, like other parts of the energy business, GTL suffered from the rampant cost inflation that coincided with the 2004-2008 oil-price boom. Oryx got the go-ahead before costs began their steep rise and ended up costing just over a $1 billion. But a similar project, Escravos GTL, which received approval a year later, could end up costing $6 billion, even though it uses the same technology as Oryx and has the same design capacity.
One reason for higher costs is that Escravos GTL is located in isolated swamp-land in the Niger Delta, as opposed to Qatar’s state-of-the-art Ras Laffan Industrial City. Just preparing the Escravos site involved dredging nearly 4 million cubic metres of sand to make way for the sophisticated system of steel piles being used to support the plant.

Chevron, the operator, has also had to cope with Nigeria’s security threat and to establish a new, high-tech sector for the Nigerian energy industry. Yet the original budget was $1.7 billion, so costs look set more than to triple. The project’s planned start-up date has also slipped from 2009 to 2012. Other potential GTL developers may look on aspects of the venture as a cautionary tale.

Reasons for optimism

Then again, there are reasons for optimism. Cost inflation is in reverse, following the collapse in oil prices in mid-2008, and this could tempt developers back into the market. Certainly, technology-development in synthetic fuels is continuing.

In addition, there are other ways of using FT technology. For example, when oil is produced offshore, natural gas is produced with it, but often — especially in remote offshore locations — there will be no pipeline to export this so-called associated gas to market and building one would be too expensive. Two commonly used solutions, burning the gas off (flaring) or venting it, are not sustainable: both are bad for the environment and a waste of a valuable resource.

CompactGTL, a privately owned UK technology company, says FT technology could be the answer. Its idea — which has drawn interest from Brazil’s state-controlled energy company, Petrobras, predominantly an offshore oil producer — is to convert associated gas into synthetic crude oil at the point of production, using FT technology. The synthetic crude oil is then mixed into the flow of conventional crude oil being pumped out of the oil field and exported to market.

Not only does this get round the environmental problem presented by flaring and venting, but it generates a new and lucrative source of revenue by turning previously useless gas into a marketable and valuable commodity. CompactGTL estimates that associated gas reserves around the world with no commercial value exceed 28 trillion cubic metres — a large and potentially lucrative market with an environmental dividend.
The world’s premier oil and gas forum

The World Petroleum Council is the world’s premier global oil and gas forum and is the only international organisation representing all aspects of the petroleum sector. 2008 marked the 75th anniversary of the organization. The WPC was established in 1933 with the intent to promote the management of the world’s petroleum resources for the benefit of mankind.

The WPC’s prime value to the oil and gas industry is to catalyse and facilitate dialogue amongst stakeholders that will contribute to finding solutions to key technical, social, environmental and management issues facing the industry. In doing so, the WPC will contribute towards sustainable growth.

The WPC provides a neutral and non-political forum and works to bring together in dialogue the various sectors of society that have views on specific issues.

WPC is a non-advocacy, non-political organisation and has accreditation as a non-governmental organisation (NGO) from the United Nations (UN). The WPC is dedicated to the application of scientific advances in the oil and gas industries, to technology transfer and to the use of the world’s petroleum resources for the benefit of all.

Headquartered in London, the World Petroleum Council includes 60 member countries worldwide representing over 95% of global oil and gas production and consumption. WPC membership is unique as it includes both OPEC and non-OPEC countries with representation of national oil companies as well as independent oil companies.

Each country has a national committee made up from representatives of the oil and gas industry, academia and research institutions and government departments. Its governing body is the Council consisting of representation from each of the country National Committees.

The World Petroleum Congress

Every three years, the WPC organises the World Petroleum Congress as the principal meeting place for the international oil and gas industry. Hosted by one of its member countries, the triennial Congress is also known as the “Olympics” of the petroleum industry and covers all aspects of the industry from technological advances in upstream and downstream operations to the role of natural gas and renewables, management of the industry and its social, economic and environmental impact.

In addition, outside stakeholders such as governments, other industry sectors, NGOs, academia and international institutions have also joined in the dialogue. Qatar will be the host of the 20th World Petroleum Congress in 2011.

Beyond the triennial Congress, the World Petroleum Council is regularly involved with a number of other meetings such as the WPC Youth Forum, the WPC-UN Global
Compact Best Practice Forum and a joint WPC/OPEC workshop on CO₂ sequestration, as well as regional meetings, for example for Latin America in June 2010. Other events so far have also focused on dispute resolution, calculating reserves and resources, regional integration and oil, gas and infrastructure developments in Africa.

Legacy
As a not-for-profit organisation the WPC aims to ensure that any surpluses from its Congresses and meetings are directed into educational or charitable activities in the host country, thereby leaving an enduring legacy in the Host country.

The WPC Legacy Programme started in 1994 with the 14th World Petroleum Congress when Norway put the surplus funds of the Congress towards the construction of Stavanger’s state-of-the-art Petroleum Museum to help inform and educate the public and in particular the younger generation on the history and operations of the petroleum sector.

Young people were also addressed as a key aspect of the 15th World Petroleum Congress in Beijing through its theme “Technology and Globalization – Leading the Petroleum Industry into the 21st Century”. To support their education and future involvement in the petroleum industry, the Chinese National Committee donated all computer and video equipment used at the Congress to its Petroleum University.

Profits from the 16th Congress in Calgary were used to endow a fund providing scholarships to post-secondary students in petroleum-related fields. The Canadian Government Millennium Scholarship Foundation matched the amount dollar for dollar which created an endowment that to-date has supported over 2000 students.

The 17th World Petroleum Congress was the first to integrate the concept of sustainability throughout its event. The Brazilian hosts took responsibility for the 16 tonnes of recyclable waste generated by the Congress, with the proceeds of the recycling activities passed on to a local co-operative in Rio de Janeiro.

Vision, Mission and Values

Vision
An enhanced understanding and image of the oil and gas sector’s contribution to sustainable development.

Mission
To promote the development and utilization of oil and gas resources and other energy sources in an efficient and sustainable way, for the benefit of the current and future generations.

The WPC is the only global organisation that represents all aspects of the oil and gas sector, with the purpose of providing:

• an enhanced understanding of issues and challenges
• networking opportunities in a global forum
• co-operation (partnerships) with other organisations
• an opportunity to showcase the industry’s technical achievements
• a forum for developing international business opportunities
• information dissemination via congresses, reports, regional meetings and workshops
• initiatives for recruiting and retaining expertise and skills to the industry
• promoting best practises in the production and consumption of energy resources.

Values
The WPC values strongly:

• Cross-national dialogue and networking
• Respect for individuals and cultures worldwide
• Unbiased and objective views
• Integrity
• Transparency
• Good governance
• A positive perception of the industry
• Science and technology
• The views of other stakeholders
Janeiro. Practical help was provided by 250 volunteers who painted a public school and collected 36 tonnes of rubbish in a special community effort, donating all proceeds to some of the poorest inhabitants of Rio. The surplus funds of the Congress were used to set up the WPC Educational Fund in Brazil, which was further increased in 2005 with tax initiatives added by the government.

The 18th World Petroleum Congress also chose a sustainability focus for the first WPC held in Africa. Besides providing skills development and practical training for unemployed youths in its unique Volunteers programme, the South African National Committee set up the 18th WPC Educational Legacy Trust to provide financial assistance to young South Africans wishing to pursue a qualification in petroleum studies.

In 2008 the Spanish organisers of the 19th Congress in Madrid were the first to achieve a carbon neutral event by addressing the carbon footprint of each delegate attending the event and neutralising its impact for the coming generations. Young people were the main benefactors of a number of legacy projects created by the surplus from the event.

Qatar, Host for the 20th World Petroleum Congress in 2011, is already considering the long term legacy they wish to leave through the first Congress to be held in the Middle East, with education likely to be playing a key role in the allocation of surplus funds.

**WPC Structure**

The Council is the governing body of the World Petroleum Council which convenes once a year. Its global membership elects the President and an Executive Committee every three years to develop and execute its strategy. The Council also selects the host country for the next World Petroleum Congress from the candidate countries. To ensure the scientific and topical quality of the event the Council elects a Congress Programme Committee whose members are responsible for developing the high-level content for its Congress Programme.

The Secretariat of the World Petroleum Council is based in London, led by the Director General and his dedicated team.

**WPC Youth**

Attracting young people to the oil and gas industry, keeping them involved and engaging them directly in WPC activities is a key strategic issue for the WPC. In response, WPC initiated a number of activities to engage youth in the industry and enhance their involvement in setting WPC’s agenda for the future.

The process began with the 1st Youth Forum in Beijing in 2004 where the WPC invited young people to address the future challenges for the petroleum industry. Held under the theme “Youth and Innovation – the Future of the Petroleum Industry” the Forum was an overwhelming success and won widespread acclaim from its participants. The authors of the best papers were invited to the 18th World Petroleum Congress in Johannesburg the following year.
To continue the dialogue and to enhance the involvement of young people in its agenda, the WPC established a Youth Committee in 2006. The 17 young people under 35 from WPC member countries act as ambassadors for the next generation, provide a young people’s perspective for the Council’s work and help put in place strategies to engage youth around the world in the petroleum industry.

Their mission is to promote a realistic image of the petroleum industry amongst the youth together with its challenges and opportunities and initiate the creation of a collaborative and global forum for young people to be heard and new ideas to be championed.

The Committee’s first task was to create a series of activities for the Youth Programme of the 19th World Petroleum Congress.

The new Youth Committee was elected during the 2008 Council meeting and play a major role in planning for the 20th World Petroleum Congress taking place in Qatar in 2011. They also play a key role in the organisation of the 2nd WPC Youth Forum under the theme of “Energise Your Future”, in Paris, France, November 18-20, 2009.

Members of the WPC Youth Committee contributed to the programme development and the concept of an online youth network “Energise My Network”, which will provide an ongoing networking opportunity for young people interested in the petroleum industry.

The members of the Youth Committee continue working with each other and the Council’s bodies to engage with students and young professionals to design a sustainable future and promote their message that the energy sector is a challenging and exciting industry to work for.
Energy security

One of the goals of energy policy-makers in economies that rely on large amounts of imported energy is ensuring they have energy security. That means that they want to have access to flows of energy that aren’t likely to be interrupted and to have contingency plans at the ready if something does go wrong.

That’s not that easy: around 70% of the world’s conventional proved oil reserves are located in seven countries — Saudi Arabia, Iran, Iraq, Kuwait, the United Arab Emirates, Venezuela and Russia. And half of the world’s conventional natural gas is in just three nations — Russia, Iran and Qatar.
People

Ingenuity

Creativity

Commitment

Integrity
For Total, satisfying energy needs and controlling the environmental impact of our activities are our top priorities. In our search for new sources of fossil and renewable energy (such as solar and biomass), the Group is working hard to achieve greater energy efficiency and optimise processes to cut greenhouse gas emissions. With a pilot project to capture and store CO₂ in France’s Lacq basin, Total is developing innovative technology to confront global warming. www.total.com

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