Energy

Monday October 14 2013

www.ft.com/reports | @ftreports

Stakeholders struggle to strike the right balance

While the US enjoys cheap gas, Europe has become a battleground of conflicting priorities and worries over prices, writes *Guy Chazan*

Powerful combination: wind turbines in front of an RWE Power brown coal plant near Cologne, Germany Alamy

When Ed Miliband, leader of the UK's opposition Labour party, promised in September to freeze energy prices if he won the country's next general election, it caught Britain's business elite by surprise. It should not have done.

In stark contrast to the US, where gas prices fell to 10-year lows last year, the question of rising energy costs is coming to dominate the political agenda in Europe. It is an equally hot topic in Japan, which is having to rely on expensive imported gas as it shuts down its nuclear reactors. In many countries, it is becoming one of the defining issues of our time.

It is a problem that not only affects hard-pressed consumers struggling to pay their bills amid recession and economic hardship. It is also hurting European industry, which is becoming increasingly outspoken on the subject. Business leaders blame the growing burden of environmental levies and renewable energy subsidies.

Jim Ratcliffe, chief executive of Ineos, one of the world's largest chemicals groups, says the danger is that some companies, especially manufacturers, will move to places where energy is cheaper.

"It's fine being very, very green, but not if you're interested in manufacturing," he says. "The UK is already disadvantaged on the wholesale cost of energy, and then it puts taxes on it. Anybody who's an energy user is just going to disappear."

European companies say high energy costs mean they are less competitive than their counterparts in the US, where the shale boom has led to lower natural gas prices and heralded an industrial renaissance.

The gap in competitiveness was the central theme of a summit of EU heads of government in Brussels in May, when the European Commission revealed that gas prices for industry fell by 66 per cent in the US between 2005 and 2012, whereas they rose 35 per cent in Europe.

> 'It's fine being very, very green, but not if you are interested in manufacturing'

That price difference is leading to some doom-laden pronouncements.

"There is no near-term cure for Europe's energy price gap with the US – be it in shale gas, liquefied natural gas or US imports," says Johannes Teyssen, chief executive of German utility Eon. "Companies will continue to move overseas as a result." European policy makers should "focus not on correcting the situation but [on] not making it worse", he adds.

Japan pays about five times more for its natural gas than the US and has become a lot more dependent on the fuel since it started shutting down its nuclear reactors after the 2011 Fukushima disaster.

Its utilities rely on expensive imports of LNG, crude oil and coal to replace nuclear, which once accounted for 30 per cent of electricity generated in Japan. The government has allowed them to pass some of the extra cost to consumers. In August, the price of electricity in Tokyo was 15 per cent up on a year earlier.

In Europe, the debate centres on the so-called energy "trilemma". European energy policy has been designed to pursue three objectives: mitigating climate change by reducing carbon dioxide emissions, achieving security of supply and making sure energy is affordable to consumers.

In the years before 2008, the imperative of preventing global warming loomed largest. The EU adopted ambitious goals for cutting carbon and sourcing more and more energy from

Continued on Page 3

Inside »

Over a barrel
A ban on US oil exports may lead to a glut with no outlet
Page 2

Shale challenge
Russia may have best chance of emulating success in North America
Page 2

N-power revival is thwarted
Safety and cost issues have put future in doubt
Page 3

Green Germany comes at a cost
Renewables plan will survive but may need revision
Page 4

King Coal's rise
China and India will drive demand but is peak global usage in sight?
Page 5

Politics means industry is not being allowed to do what it does best

Opinion
NICK BUTLER

With the world's population growing by almost 10,000 a day, and more and more people in Asia and Latin America enjoying access to effective spending power for the first time, the energy business should be a thriving and happy place.

It is not.

Across the sector, the mood is downbeat. The talk is of building resilience against risks and threats.

An industry that ranges from utilities and exploration companies to the builders of wind farms is at odds with two key stakeholders – investors and politicians.

The risk of continued conflict between them is that the sector will not be able to fund all the investment required.

Energy and politics are inseparable. John D Rockefeller's manipulation of the transit routes and refineries in the US ended in the break-up of corporate power. In 1953, the attempts of Iranian prime minister Mohammad Mossadegh to reassert national control over the resources owned by the Anglo-Persian Oil Company led to a coup and the fall of his government.

At a more mundane level, the sector is well accustomed to a running battle over taxation, royalties and pipeline tariffs.

But the 21st century is bringing different challenges. The energy business sector finds itself in the crosswinds of at least three political debates – on climate change, the cost of living and national and international security. The importance of the three varies from one country to another and the rank order can shift rapidly.

In the UK, the energy debate has shifted from climate to costs in a matter of months. Energy companies there are also threatened with a price freeze designed to win the votes of consumers.

German utilities are still trying to recover from Chancellor Angela Merkel's overnight decision to close Germany's nuclear power stations. In France, the nuclear sector has to deal with a new tax designed to fund a transition to renewables. Across Europe, solar and wind businesses are nervous that generous subsidies will be cut back.

And in the US, companies are bemoaning the breakdown of the rule of law evidenced by the handling of compensation claims after the disaster at BP's Macondo well in the Gulf of Mexico.

Energy companies are usually run by engineers who deal in facts and data and whose philosophy is firmly rationalist. Now, though, they must also be attuned to ever changing political tides, and able to work in circumstances where the rational is often trumped by the popular and the expedient.

Business can complain that particular policies are wrong or that change makes long-term planning impossible. They can point to the number blindness in the attack on profits that may be counted in billions but reflect no more than a modest return on large capital investments.

But their complaints make little difference because, for politicians, energy policy has become an arena within which the biggest debates can be played out.

Energy companies may not be to blame for climate change or squeezed living standards, but they make easy targets and convenient villains. Few people protest if their profits are taxed a bit more.

All this increases costs and puts a restraint on the companies' freedom of action. It also complicates the relationship of the sector to investors. The market has fallen out of love with most of the biggest companies. Energy stocks lag behind the main indices and the gap is widening. Many provide secure dividends but there is little or no growth. Price/earnings ratios have fallen sharply over the past decade. There is a pervasive belief that management and boards of directors have lost touch with the interests of shareholders.

This mood extends beyond the oil majors. Companies such as Gazprom are struggling to keep up with a rapidly moving gas market driven by gas-to-gas competition. On the evidence of Flamanville, EDF's ill-starred nuclear plant now under construction, the French company has lost the ability to control costs. In Japan Tokyo Electric Power seems to have lost control of everything since the Fukushima disaster.

> The energy sector has become simultaneously a punch bag and a milch cow

Utilities and retail businesses are trapped by fierce price competition in markets that, at least in the developed world, are static or shrinking.

There is no appetite for rights issues and a strong desire among shareholders to see more of their money returned. So far, investor activism is focused on smaller companies such as Hess, the US oil company, but it will spread.

The risk is that the twin pressures of politics and investor sentiment drive funds away from a sector that needs to invest on a huge scale to meet global demand over the next two decades. According to the International Energy Agency, about $37tn is needed – much of it in unfamiliar parts of the world that carry added risks. Such sums will be available only if the policy frameworks and terms, including shareholder returns, are acceptable and secure.

The energy sector has become simultaneously a punch bag and a milch cow. Both success and failure are punished.

There are faults within – particularly the neglect of shareholders and a reluctance to accept that costs be controlled.

Something will have to give, however, because while the energy business can live without being loved, it can only do its job if its indispensable role is respected and rewarded.

Nick Butler is visiting professor and chair of the Kings Policy Institute at Kings College London. His blog on energy and power appears at blogs.ft.com/nick-butler

Energy

Gushing reports: pump jacks in the Midway Sunset oilfield, California, near the vast Monterey shale formation Reuters

Export ban has producers over barrel

US oil industry The country may find itself left with a glut that has nowhere to go, reports *Ed Crooks*

Only five years ago, the US ban on crude oil exports looked about as relevant a piece of legislation as an ordinance against riding unicorns.

Today, it is rapidly becoming one of the US oil industry's most worrying issues: a regulatory restraint that is affecting business decisions, and is likely to create increasingly severe distortions in the next few years.

It is particularly troubling because although the prohibition is an artefact of a very different time, it is likely to prove difficult to remove.

As Maria van der Hoeven, executive director of the International Energy Agency, put it in an article for the Financial Times this year: "Washington will need to address this misalignment, lest the great American oil boom goes bust."

Until very recently, US crude oil exports seemed a purely theoretical proposition. After steady decline since its peak in 1970, US crude production hit a low point of just 5m barrels a day in 2008, and seemed to be heading inexorably lower. Domestic production provided just two-thirds of the crude used in US refineries.

Half a decade later, the position has been turned on its head.

Booming production and weak demand have sent America's oil imports plunging, to the point that it has fallen behind China as the world's largest net oil importer.

Some analysts believe that by the end of the decade, US net oil imports, which are about 6.2m b/d today, may be negligible.

Gushers of light and sweet oil are flowing from the Eagle Ford shale of south Texas and the Bakken shale of North Dakota, creating a flood of crude in the storage tanks and refineries of Oklahoma and the Texas coast.

If, as many analysts expect, production from those shales continues to grow, and production from newer growth areas such as the Permian Basin of west Texas also rises strongly, the US is likely to be left with a glut of oil in the Gulf of Mexico region that has nowhere to go.

The US ban on crude oil exports dates from the 1975 Energy Policy and Conservation Act, reinforced by the 1979 Export Administration Act. In the energy crisis-conscious 1970s, with US oil production in steep decline, these seemed sensible measures to protect domestic crude for American consumers.

Crude oil can be exported with a special licence, but very few have been granted. Exports from Alaska were approved in 1996, although no crude has actually gone to a foreign market since 2004.

A few licences for exports to Canada that have a special dispensation making approvals easier were sought by oil companies last year. A single cargo of oil left the US for China this year, apparently foreign crude that was being re-exported. In general, though, crude is trapped in the US.

Gas exports face similar restrictions under the 1938 Natural Gas Act, but the Obama administration has been moving to relax those restraints. More than 20 projects have been approved to export liquefied natural gas to countries that have a trade agreement with the US, and four have been approved to export to countries without such agreements.

> 'It would be tough even for a Republican from Texas to [allow more oil exports]. For Obama, it's even more so'

Licences for oil exports, however, are more difficult to obtain. As Scott Lincicome of the Cato Institute, the free-market think-tank, puts it: "With natural gas, the law is 'export unless', but with crude oil the law is 'ban unless'."

As the build-up of crude in the US began, it drove down West Texas Intermediate and other onshore benchmarks relative to internationally traded crude. Last November, the spread between WTI and Brent prices widened to $26 per barrel.

Since then, added pipeline capacity has come on-stream to carry oil to the Gulf of Mexico coast, and more is coming, including the lower section of the controversial Keystone XL project, now known as the Gulf Coast Project, which is set to be in use before the end of the year.

The effect of that has been to close the WTI-Brent spread down to about $7 per barrel, but promises merely to shift the glut down to the gulf region.

Already, refiners have been saying that they no longer use any imported light and sweet (low-sulphur) crude in their gulf coast refineries, because those varieties are in plentiful supply from US production.

Many refineries in the region, however, have been designed to work best with heavy and sour (high-sulphur) crude, and have relationships with parent companies in Saudi Arabia and Venezuela that mean they will want to continue importing.

As a result, Mr Lincicome says, the problems of excess US oil in the gulf region will become critical long before oil imports actually drop to zero.

Companies have been getting around the ban by exporting more refined products, including very lightly refined oil that requires further processing. US refined products exports have trebled since 2005.

Other expensive workarounds are being used, including transporting more oil by train and tanker to the east and west coasts.

Before much longer, however, the export ban risks creating an artificial glut of US oil, forcing down prices and choking off production.

For both President Barack Obama and the US Congress, there is little political capital to be gained from allowing more oil exports, pushing up domestic oil prices to help foreign consumers and the oil companies.

"It would be tough even for a Republican from Texas to do it," says the Cato Institute's Mr Lincicome. "For the Obama administration, it's even more so."

As the tensions mount, the oil industry can be expected to become increasingly vocal.

The impact of the export ban may be a problem that comes with success, but it is nevertheless a serious threat.

LNG projects from Africa to Australia seek buyers

Gas

Ajay Makan finds rising demand is a given, but supply is harder to predict

Only one thing appears certain in the global gas industry: demand is set to rise for many years to come.

As China builds more gas-fired power stations and public transport fleets look to adopt the fuel, the International Energy Agency forecasts gas consumption will increase 50 per cent from 2010 levels by 2035.

Where supply will come from, on the other hand, is a great unknown.

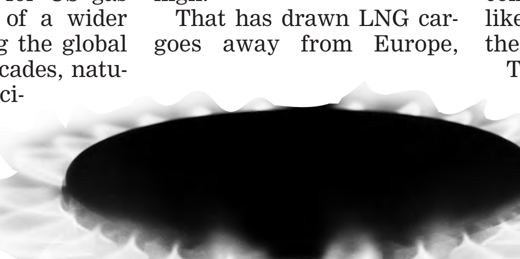
And that means the price of gas, on which billions of dollars of investment in new facilities from Australia to east Africa and Canada depends, is perilously difficult to estimate.

Much of this uncertainty can be traced to a single disrupting factor: the shale gas revolution in the US.

Having pushed US gas prices to decade-low levels last year and encouraged a domestic industrial renaissance, the shale gas glut is now set to be exported. Exactly how much US gas reaches foreign shores will have huge consequences for whether projects in other areas go ahead.

Neil Upton, head of energy and infrastructure at SJ Berwin, a law firm, says: "As international companies get more wedded to the idea that shale gas is a real option, it is shortening the tenor of contracts they are willing to sign with other suppliers and that creates uncertainty."

The potential for US gas exports is part of a wider change sweeping the global industry. For decades, natural gas was principally transported by pipeline within discrete regional markets and sold at prices linked to oil, to give companies certainty over revenues.



But technology that allows gas to be supercooled into liquid means it can now be transported by tanker to any port with a facility to turn it back into usable fuel. That has allowed for the development of a global market, and for gas prices to decouple from oil prices.

BG, the energy company, says liquefied natural gas – or LNG – will account for 14 per cent of total gas demand by 2025, up from 11 per cent today.

For now, however, LNG supplies are struggling to keep up with demand.

In Asia, purchases by companies in South Korea China, and Japan, where gas-fired power stations have been working overtime to replace nuclear capacity turned off after the Fukushima accident, is keeping import prices high.

That has drawn LNG cargoes away from Europe, forcing the continent to turn back to piped gas from Russia.

LNG supplies fell for the first time in several years in 2012, and with the export programmes of Egypt and Algeria disrupted by security concerns, it could fall again this year.

At the same time countries including India, Latin American states and even Gulf countries have been installing regasification capacity, adding to potential demand. Thierry Bros, senior LNG analyst at Société Générale, says that LNG import facilities operate at only 30 per cent capacity, because of a shortage of available cargoes.

It will take several years to meet this pent up demand. LNG projects take many years, and many billions of dollars of investment, to build. So projects commissioned now are unlikely to be operating before the end of the decade.

The next consignment of gas to hit the market will be from a series of Australian projects. Wood Mackenzie expects Australia to add 70m tonnes a year of export capacity over the next five years, displacing Qatar as the world's biggest supplier and increasing global capacity by a quarter from current levels.

Goldman Sachs analysts expect supply to be plentiful and prices to soften from late 2015 to the end of 2017 as a result. The big question is what happens after that.

BG estimates that $400bn of investment will be required by 2025. There is a queue of projects lined up to bid for that investment, from Yamal in Russia to Kitimat in British Columbia near Canada's west coast and a huge project planned in Mozambique. Significant offshore gasfields have also been found in neighbouring Tanzania.

All the projects are competing to tie in buyers to long-term contracts. Because of the upfront cost involved, companies need to display guaranteed revenues before banks will extend project finance.

But the potential flood of US gas complicates these negotiations. The cost of US LNG is expected to be relatively low, because most projects already have shipping terminals – a legacy of the years before the shale gas revolution when the US was expected to have to import LNG.

The US government has appeared increasingly willing to grant licences for LNG export projects, despite concerns about higher domestic prices.

> 'It is very easy to tilt the balance from a relatively tight market to a well supplied one'

That means the cost of supply, as well as buyers' willingness to depend on the US market, are likely to determine how many US projects proceed, and how big a market is left for others across the world.

Analysts tend to agree that the new Australian projects are priced out of the market for now. For other countries much will depend on transport costs to the largest markets in Asia.

After shipping costs, Goldman Sachs analysts believe gas from Mozambique will cost between $11.50 and $11.80 per million British thermal units (mBTU) in Asia – about the same as their estimate for US gas. They think Yamal's price would be only slightly higher, while projects on the west coast of Canada could also be attractive because of their proximity to Asia.

With uncertainty remaining over so many projects, the outlook for price is hard to gauge.

Samantha Dart, an analyst at Goldman, says: "It is easy to tilt the balance from a relatively tight market to a well supplied market, because the size of these proposals is very significant."

North America sets pace that others will find hard to match

Global shale

Russia may have the best chance of emulating the US, writes *Guy Chazan*

This summer, the small English villiage of Balcombe became an unlikely battleground in the increasingly polarised debate over hydraulic fracturing.

Opponents of the technique, also known as fracking, converged on the West Sussex beauty spot to protest against plans by the independent energy company Cuadrilla to undertake exploratory drilling for oil in the area. Green MPs, eco-warriors and well-heeled local residents joined forces to block the site.

Cuadrilla was forced to suspend operations after a group called "No Dash for Gas" threatened direct action against the company.

The events at Balcombe underscored the challenges facing any energy company attempting to export the US shale revolution.

Shale gas is present in huge quantities in many parts of the world, not just North America. The US Energy Information Administration has said that China, Argentina and Algeria have bigger reserves than the US.

But the bare statistics tell only part of the story. In many cases, these resources will be far harder to extract and market than they have been in America. "Not all shales are created equal," says Dale Nijoka, oil and gas sector leader at EY, the professional services firm.

The US shale industry grew up in areas that have been producing oil and gas for decades. Early pioneers benefited from the presence of a well-established oilfield services sector, with large fleets of drilling rigs, sophisticated financial markets, and a favourable fiscal regime.

Another key factor was the private ownership of reserves: in most other countries, oil in the ground is owned by governments, giving local residents little financial incentive to consent to drilling on their land.

In short, the unique set of circumstances found in the US paved the way for a boom. And they may be hard to reproduce. "No other country outside the US and Canada has succeeded in combining these factors to support production growth," says Christof Rühl, chief economist at BP.

Learning how to extract the gas is just part of the battle: companies also have to figure out how to ship it to consumers. "In a lot of countries you don't have the infrastructure in place to get the gas to market," says Mr Nijoka.

Strong environmental opposition can also slow things, as has been seen in France and Bulgaria, two countries with extensive shale resources that have banned fracking.

As a result, no one is expected to challenge the supremacy of the US in shale gas and "tight" – or hard-to-extract – oil for the foreseeable future.

In its latest energy outlook in January, BP said global output of shale gas would treble and that of tight oil would grow more than sixfold by 2030. But it said North America would dominate production of such resources over the next two decades.

Others will certainly try to emulate the US's success. One country that could potentially see a US-style shale boom is Russia: its Bazhenov shale in western Siberia is thought to contain 100bn barrels of recoverable oil, making it five times larger than North Dakota's Bakken, the motor of America's oil renaissance. BP says it expects Russia to be producing 1.4m barrels a day of tight oil by 2030.

The Bazhenov lies in an area where oil has been extracted for decades. That part of Siberia is criss-crossed by roads, pipelines and other oil and gas infrastructure, and there is a trained and experienced workforce readily available.

US service companies such as Schlumberger are shipping advanced fracking technology to the Bazhenov straight from Texas and Pennsylvania to try to tap the region's oil. The Russian government has introduced generous tax breaks to encourage investment.

But it may take years before oil companies operating in the Bazhenov manage to crack its code. The geology is complex and poorly understood, and recovery factors are much lower than in conventional reservoirs.

Meanwhile, the drive to exploit China's shale resources has also turned out to be harder than initially thought. With its huge reserves and vast domestic market, China presents a unique opportunity for shale developers. The government is also supporting the industry, in the hope that it could reduce Beijing's dependence on dirty coal and imported gas.

But early results are not particularly encouraging. Royal Dutch Shell, one of the biggest players on the Chinese shale scene, has found the geology tough going.

There have been protests from villagers upset at the dust and noise and the impact on the local environment. Power and water shortages are common.

Few now believe China will meet its 2015 output target of 6.5bn cubic metres – which anyway is equivalent to only 2 per cent of the country's total gas output.

Another country that had high hopes of becoming a big shale gas producer is Poland. But the outlook there is also deteriorating. Unable to find commercial quantities of gas, Marathon Oil and Talisman Energy have joined ExxonMobil in pulling out of the country.

Then there is the UK. Here, the stage appears to be set for a shale boom. A recent estimate suggests there is about 1,300tn cubic feet of shale gas lying under 11 counties in the north of England, although only a small fraction of that may turn out to be technically recoverable.

The government has encouraged the industry,

> 'There is a fear that it's all moving too quickly and no one has assessed the possible consequences'

promising substantial tax breaks. Locals should also benefit, with companies pledging £100,000 to every community situated near an exploration well, as well as 1 per cent of the revenue if gas is extracted. David Cameron, the prime minister, has lobbied hard for shale, saying it could bring down fuel bills.

Hamish McArdle, partner in oil and gas at the law firm Baker Botts, says: "There is a general sense that the UK has a history of extractive industries both onshore and offshore, a regulatory framework that's fit for purpose and lots of change in terms of taxation as well as the promise of reform on the permitting and planning side."

But despite all that, it is still unclear that Britain's shale industry will ever take off on the kind of scale seen in the US. Events at Balcombe do not bode well for the sector.

Mr McArdle thinks the government's outspoken support for shale may have run so far ahead of public opinion that it could provoke a backlash.

"There is a fear that it's all moving too quickly and no one has assessed the possible consequences," he says.

Companies will clearly have to do a lot more work to reassure the locals that fracking is safe; otherwise drilling sites across the country might have their own version of this summer's Battle of Balcombe.

Energy

Global revival threatened by safety fears and building costs

Nuclear It may make sense to use but who will go ahead and do it, asks *Sylvia Pfeifer*

Brief visit: Japanese prime minister Shinzo Abe is shown leaking water tanks at Fukushima last month Getty

Nuclear power provides reliable, low-carbon energy, so it should be in an enviable position to compete against other sources of electricity as governments try to cut harmful carbon emissions while ensuring the lights stay on.

Yet the global renaissance of atomic power predicted by many a few years ago is not taking place as expected.

The industry is still suffering the consequences of the disaster at Japan's Fukushima plant in 2011, which prompted a number of governments, notably Germany, to scale back their commitment to nuclear energy.

But there is another threat: the shale gas revolution that has gripped North America is helping to prompt a re-evaluation not just of new reactors but of existing plants.

In the US, four reactor closures have been announced this year, two for maintenance and two in part because of low natural gas prices. The electricity they supplied is being replaced by gas-fired power, which will increase carbon emissions. "This was an agonising decision," said Leo Denault, Entergy's chairman and chief executive, when the Louisiana-based utility announced in August it would shut down its 41-year-old plant Vermont Yankee next year.

Energy market conditions, including low gas and electricity prices resulting from the shale boom, however, meant it was the right move to make.

The company added that Vermont Yankee was a small, standalone plant, with a capacity of 650MW, which meant that it had relatively high costs and a greater burden of compliance than larger plants.

The plant at Vernon on the Connecticut River was expected to break even in 2013 and would have fallen into loss in subsequent years, the company said.

While four new reactors are expected to come into service in the US over the next few years, analysts believe more of the older nuclear plants will shut down, as the costs of maintaining them while also having to compete with low gas prices make further investment uneconomic.

If the dynamics of North America's energy markets have changed thanks to shale, most market watchers do not believe nuclear faces the same threats elsewhere.

In the UK, for example, the government is going ahead with new plants even as it promotes the development of the country's shale resources.

> 'The big problem with nuclear is the construction and upfront cost'
> George Borovas
> Pillsbury

According to Alex Hand, partner at Eversheds, the law firm, there is still a "question mark" over just how big the reserves of shale are and over what time period they will be developed in reality.

Nuclear, he argues, has to be in the mix for the UK and other European countries if they are to mitigate the carbon cost and reliance on foreign – and often uncertain – lines of supply that use of gas brings.

Not only that, but there is no guarantee, even in the US, that gas prices will stay low and that electricity bills will therefore also remain relatively low.

Tony Ward, head of power and utilities for the UK at EY, the professional services firm, says: "If you are progressively closing old nuclear plants that have been producing cheap power, you are placing a big bet that the cheap gas you are getting today will keep staying cheap."

Whereas the biggest cost for a nuclear power plant is construction and fuel is only a tiny percentage of the eventual running cost, the gas burnt by a combined cycle gas turbine (CCGT) is a significant element of the output price.

Over the whole lifetime of a CCGT project, from construction through to closure, the cost of the gas burnt to generate electricity will typically equate to 65-75 per cent of the total cash flows of the project. It is therefore the biggest determinant of the output price, points out Mr Ward.

"Gas can also go elsewhere depending on the price, whereas once nuclear plants are built, you keep running them," he adds.

Turkey, for example, which has a very large energy import bill, is planning to build nuclear reactors as well as coal plants in an attempt to cut its reliance on foreign supplies.

For those countries looking to build new plants, the main challenge remains the upfront cost.

In the UK, the government is offering renewables and nuclear power support in the form of contracts for difference. These will guarantee companies a fixed price for their electricity over the lifetime of a plant.

George Borovas, head of nuclear projects at Pillsbury, an international law firm, says: "The big problem with nuclear is the construction and upfront cost. You have to be smarter and more innovative in terms of how you fund plants."

The industry is looking at new ways to fund plants, in particular through the use of export credit agencies.

Taking on equity partners is another route. EDF, the French utility spearheading Britain's nuclear drive, for example, is talking with China General Nuclear Power after Centrica, its previous partner, pulled out of a project to build two reactors at Hinkley Point in Somerset.

Industry supporters also argue that what is needed are "repeat projects" that will enable operators to cut the costs associated with first-of-a-kind technologies.

In western Europe, all eyes are on what happens in the UK. According to Eversheds' Mr Hand, time is of the essence.

While the country is an attractive market for construction companies, reactor designers and operators, nuclear new build is still taking a long time to get under way.

"We are battling against other markets that may have more money to spend. There is a risk over the next two years if we don't see very significant moves, of it not happening," says Mr Hand.

Spikes in demand put pressure on grid operators to keep lights on

Infrastructure

Avoiding blackouts is a big problem in many countries, says *Michael Kavanagh*

Just how confident Britain can be about keeping the lights and central heating on was thrown on to the political agenda last week. The UK's national grid operator warned that the narrowing gap between peak demand and maximum generating capacity had increased the chances of power cuts this winter.

In reality, the chances of outages remain remote and would depend on a highly unlikely combination of extended cold weather and unplanned disruptions to power delivered into the grid, explains Richard Smith, National Grid's head of energy strategy and policy. "We haven't a crystal ball to know how the winter will play out, but we are confident the market can deliver," he says.

It is also the case that consumers in most of the world's developed economies have become so used to a steady delivery of electricity that interruptions risk creating a minor political scandal.

As things are, interruptions are usually small in nature – the result of a road digger cutting through a local mains cable, for example.

More extensive failures are often the result of freak weather conditions – such as last October's Hurricane Sandy that hit large sections of the eastern US, causing widespread flooding and wind damage that left an estimated 8m homes without power.

But for many countries, dealing with intermittent electricity supplies is a way of life. It is a pressing issue in developing economies, where energy demand is outstripping supply and the ability of local grids to deliver.

The scale of the disruptions caused by Hurricane Sandy was dwarfed last year by the July power outages in northern India that were estimated to have affected 620m people.

Again, unusual weather conditions prompted exceptionally high power demand were blamed in part for prompting India's patchwork of grids to collapse.

The incident was described as the biggest power failure in the world to date. But it was also just the latest of frequent blackouts in a country well used to regular, if more minor, failures.

It highlighted the increasing stresses on a fast growing economy where, although a quarter of the population has no direct access to electricity, peak demand is estimated to outstrip supply by nearly a 10th.

Grid operators in Indonesia were also embarrassed after the country was hit by one of the world's worst blackouts in 2005, when the country's fragile grid system failed, cutting supplies to 100m people and leaving Jakarta office workers stuck in lifts.

> 'We don't have a crystal ball to know how the winter will play out, but we are confident the market can deliver'

For many consumers and businesses in developing countries that lack the power generation capacity to deliver reliable electricity supplies around the clock, all that can be hoped for is that interruptions to the grid are scheduled to cause least disruption.

In Japan, the earthquake and tsunami of March 2011 and Fukushima nuclear plant failure prompted rolling blackouts as electricity in one of the world's leading economies was effectively rationed because of the shortfall in supply.

Where generation capacity is routinely smaller than demand, there is little that regional or national operators can do to guarantee supplies.

However, grid operators around the world are under pressure to ensure that power outages are not the result of their own avoidable failures caused by underinvestment and poor maintenance or planning.

And the growth of renewable energy sources creates another complicating factor in the equation.

In Europe, grid operators are increasingly grappling with the issue of how best to balance the intermittent output from growing fleets of wind farms with patterns of peak industrial and consumer demand.

The growing emphasis on unpredictable renewable energy, often produced in remote areas, also creates a problem for grid operators and generators of how to tackle power lost across long stretches of cabling.

This is in part being tackled through the development of high voltage, direct current (HVDC) cabling that can transmit electricity far more efficiently over long distances compared with traditional alternating current systems.

Friends of the Supergrid, a campaign group, advocates investment in an international web of HVDC interconnectors that would allow for the efficient transfer of solar, wind and hydro power from as far afield as Scandinavia and Morocco to large population centres in central Europe and help smooth power supplies.

However, Chris Train, director of network operations at National Grid, suggests that "demand management" in domestic markets is also an important tactic in ensuring steady and reliable supplies when grid operators face mismatches between peak demand and generating capacity.

The problem of grid operators struggling to deal with spikes in demand could be eased by offering more attractive incentives to large industrial customers willing to reduce their electricity use on request, he argues.

In essence, deals that reward customers willing to see their supplies curtailed at times of peak demand could be the most rational and economic way to ensure the lights stay on for others.

Struggle to strike the right balance

Continued from Page 1

renewable sources such as wind and solar.

The world is different now. The 2008 financial crash, the ensuing eurozone debt crisis and the weak recovery that followed have changed the parameters of the debate and made it harder for policy makers to balance what are often mutually conflicting goals.

"There's been a tangible shift in Europe," says Roger Reynolds, a utilities specialist at Exane BNP Paribas in London. "The balance has now moved away from reducing emissions at any cost to the question of affordability."

That shift has happened despite any softening in the scientific consensus on global warming. Indeed, opinion has, if anything, hardened.

The latest report by the UN's climate panel said global warming on the ground, in the air and in the oceans was "unequivocal". The panel added that scientists are 95 per cent certain that humans are the "dominant cause".

There is little evidence that the public is becoming more sceptical about climate change, certainly in Europe. What has changed is that consumers are less willing to foot the whole bill for policies to mitigate global warming.

The shift in the debate is most conspicuous in Germany, where the Energiewende – Chancellor Angela Merkel's historic drive away from polluting fossil fuels and nuclear power towards wind and solar – has left German consumers with among the highest prices for electricity in Europe.

Germany plans to raise the percentage of renewables in the electricity mix to 35 per cent by 2020 and 80 per cent by 2050. This compares with 23 per cent last year. But there is a huge price tag. The cost of the renewable energy surcharge, which is placed on all consumers' bills, is expected to jump this year from €14.1bn to €20.4bn euros, according to one estimate.

> 80%
> Target for renewables in Germany's electricity mix

The German environment ministry says the total cost of the Energiewende could reach about €1tn.

Some big energy-intensive companies have managed to win exemptions from the surcharge. But much of Germany's Mittelstand – the network of family-owned businesses that are the bedrock of the economy – are required to pay.

Peter Atherton, utilities analyst at Liberum Capital, says: "Modern industrial economies are predicated on robust, affordable and competitive energy and you mess with that at your peril."

Germany's big power suppliers, such as Eon and RWE, are also suffering from the alternative energy boom.

Germany's renewable energy law, the EEG, prioritises solar and wind power over coal and gas in the grid, which means that the many conventional power stations that have nothing to do on sunny and windy days are no longer profitable to operate.

In one of the most perverse outcomes of the Energiewende, Germany's CO_2 emissions actually rose last year. That is because the shale gas boom in the US prompted many local power generators to switch from coal to gas as a feedstock, leading to a huge influx of cheap North American coal into Europe.

As a result, coal plants have become cheap to operate and modern, efficient gas-fired power plants have been shuttered. The failure of the EU's carbon-emissions trading system has not helped.

Gérard Mestrallet, chief executive of GDF Suez, says over the past five to six years about 50,000MW of gas-fired capacity in Europe – equivalent to 50 nuclear plants – have been closed down or mothballed by 10 of the continent's biggest utilities.

That, he adds, has "implications for energy security", namely there may not be any gas plant available to provide peak power in northern Europe when the wind is not blowing and the sun is not shining.

GDF Suez is one of nine big European utilities that recently appealed for a complete rethink of European energy policy. Europe, argued Mr Mestrallet, was "destroying its energy industry through a lack of consistency, coherence and wrong decisions by the European Commission and by individual governments".

He called for a reduction in subsidies for renewables, saying they should be limited to "technologies that are not mature today – such as tidal and wave power".

It is not such an outlandish idea. Spain has cut its non-fossil fuel subsidies and other governments are thinking of doing the same.

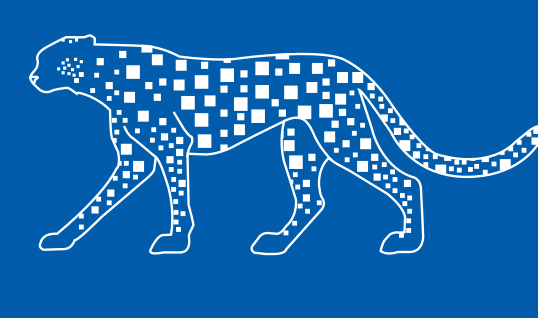
"There have been a lot of good intentions," says Eon's Mr Teyssen of Europe's energy policy. "But things are now getting out of control."

Eon and other European utilities have been lobbying Brussels to ease state aid rules so that governments can provide "capacity payments" – effectively a subsidy for gas-fired plants. This would allow power companies to keep such plants as back-up for calm grey days.

Such an approach has plenty of opposition and the likelihood is that the energy policy debate will continue to rage for years to come.

"The cost of energy is becoming a key battleground for policy makers, utilities, renewables developers and consumers," says Mr Reynolds at Exane BNP Paribas.

"It's becoming a real struggle to strike the right balance."



It's a jungle out there

Warwick Business School: a top institution for ambitious people.

At WBS we believe that sustainable and affordable energy lies at the heart of growth and prosperity across the world. Join us to learn how successful business leadership is transforming the energy industry and can transform your future as well.

The Warwick Global Energy MBA

Be part of an international cohort of industry professionals exploring the management challenges of how we will provide and use energy in the future.

Sign up for our regular newsletter, and watch our films, at our website below.

Don't forget to follow us on Twitter @warwickbschool

wbs WARWICK BUSINESS SCHOOL

T +44 (0)24 7652 4100
E warwickmba@wbs.ac.uk
W wbs.ac.uk/go/ftenergy

THE UNIVERSITY OF WARWICK

Cost burden is big issue in transformation to renewables

On the way out: an anti-nuclear protester rides past a nuclear power plant at Broksdorf, northern Germany Getty

Germany The Energiewende's broad goals are supported across the political spectrum, but changes may be inevitable, writes *Pilita Clark*

Before a single vote was cast in last month's German election, one thing was clear: whichever parties ended up in government would have to make the country's green energy policy their first priority.

Few countries have transformed their energy systems as comprehensively in the last 15 years as Germany has under its so-called Energiewende, a shift to renewable power generation.

But the cost of this transformation has become a growing concern as it has accelerated following Germany's decision to phase out atomic power in the wake of the 2011 Fukushima nuclear disaster in Japan.

So, as Germany's Chancellor, Angela Merkel, works on forming a new governing coalition after her Christian Democratic Union party's emphatic election victory, the energy industry is watching closely to see what lies ahead for the Energiewende.

In 2000, when Germany launched the generous subsidies that have driven its green power shift with the renewable energy law (EEG) that came into force that year, it obtained less than 7 per cent of its electricity from renewable sources such as wind farms and solar parks.

Last year, it obtained just under a quarter and under current government plans, it will get at least 35 per cent by 2020 and 80 per cent by 2050.

As more and more renewable energy has come on to the grid, however, its financial impact has become more noticeable, along with its effect on the broader power industry.

The cost of Germany's renewable policies for the country's electricity consumers jumped from €8.2bn in 2010 to €14bn in 2012, year, according to BDEW, the German association of energy and water industries. This year it is expected to soar to more than €20bn.

"Costs have escalated out of control," says Anna Czajkowska of the Bloomberg New Energy Finance research company. "Politicians across all parties agree they need to lower the cost of supporting renewables."

Environmental groups such as WWF say €20bn accounts for a tiny fraction of German GDP and the Energiewende has helped bring down renewable power manufacturing costs globally, especially for solar and wind power.

The German Renewable Energy Federation (BEE), adds that there are now some 380,000 jobs in the green energy industry and although electricity prices have risen, they have not increased as sharply as other energy costs, such as heating and transport.

But there is broad agreement that one aspect of the renewables programme may need urgent change: the way the cost of renewable subsidies is distributed.

Energy-hungry industries exposed to international competition are exempt from the renewable energy surcharge imposed on other consumers, meaning ordinary households have had to pay a much larger proportion of total costs.

Ms Czajkowska points out: "In 2013, the exempted companies will consume about 20 per cent of renewably generated electricity while they will only contribute about 0.2 per cent of the overall EEG surcharge. So I think the distribution issue will definitely be very high on the new government's agenda."

At the time of writing, it was not clear what the new government would look like, let alone its agenda.

Ms Merkel has been negotiating with the centre-left Social Democratic party, widely deemed the most likely coalition partner for her centre-right CDU. She was also expected to talk to the Green party, in a move that could see potential partners played off against each other.

The country's green energy transformation may feature in the talks, some analysts say.

Henrich Quick, an energy expert with the Pöyry consultancy, says: "The Energiewende is at a point where some of it now needs a major overhaul and it will be a pivotal issue in the negotiations over the make-up of the coalition."

All parties generally support the Energiewende, he says, but some want to see costs come down faster than others.

And those costs are not just attributable to the renewable energy subsidies. As with any new form of energy, the extra wind and solar power capacity spurred by Germany's financial incentives has added pressure to upgrade a national power grid that has been slow to expand in line with the growth of renewables.

This has proved a particularly acute problem for the country's offshore wind power industry. Costly delays in hooking up North Sea offshore wind parks are jeopardising the country's plans to have 10 gigawatts of offshore wind power by 2020. Some wind industry analysts think as little as 8GW or even 6GW is more realistic.

In addition, the way the EEG prioritises renewable power on the grid over electricity produced by conventional fossil fuels such as coal and gas has become contentious.

Wind and solar power plants in Germany accounted for more than 60 per cent of the national power supply capacity on Sunday June 16 this year, according to IWR, a renewable energy institute.

> 'No politician would ever think about [a return to nuclear power] in public because he would be dead politically'

The figure, a new record, underlines the success of the Energiewende. However, that success has weighed on the German utilities running conventional fossil fuel plants, exacerbating the impact of sagging economic demand.

Many power stations are no longer profitable to operate, according to one utility, RWE, which last month announced plans to halve its dividend and cut future payouts because of a fall in profits that it attributed in part to the green power boom.

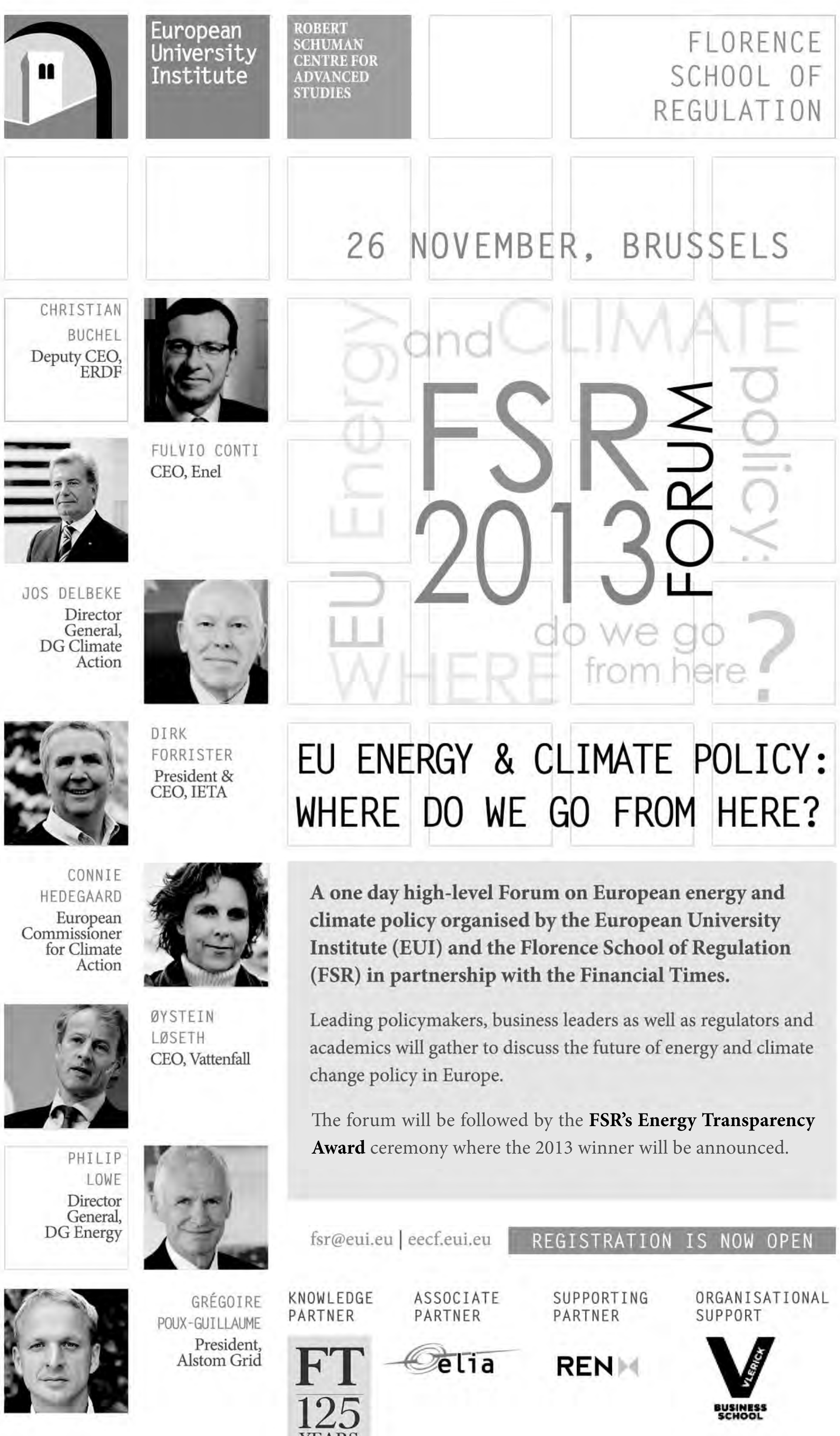
Hermann Falk, head of the BEE, agrees renewable power plants have played a part in the utilities' problems, but says some of their woes are due to their own decisions.

"They should have done their homework and calculated their risks better," he says.

Despite what many think will be inevitable changes to some aspects of the Energiewende, there is little doubt its broad goals will remain unchanged.

And one thing about Germany's energy system is certain, says Mr Quick at Pöyry: a return to nuclear power is inconceivable for any party.

"No politician would ever think about that in public because he would be dead politically," he says.



Wood fuels industrial rebirth

Case study
UK biomass projects

Drax is leading the way towards reduced use of coal, writes *Michael Kavanagh*

Ironbridge, Shropshire, birthplace of the Industrial Revolution in the 18th century, and Drax, the UK's biggest coal-fired power station near Selby in North Yorkshire, are at the forefront of change in the UK's energy landscape.

Both became centres of coal-based power generation because of their proximity to a fuel source that was cheap and plentiful. Both have emerged as 21st century centres of eco-friendly biomass burning.

In the case of Drax, preparations are being made by the UK's biggest emitter of carbon dioxide for the conversion next year of the second of its six power generation units to biomass, predominantly pellets derived from woodchip culled from forests overseas.

A third unit is due to switch from coal in 2015 under a plan requiring a £700m investment. Drax is western Europe's biggest coal-powered station to switch to biomass.

The conversion of half of Drax's generating capacity to biomass requires specially designed rail wagons, boilers and storage facilities. It will enable the plant to continue to operate as the UK's largest electricity producer well into the next decade, accounting for 7 per cent of supply on average.

The Ironbridge plant, operated by German-owned power group Eon, offers a more complicated picture. Situated less than a kilometre from the world heritage site, the facility was due to close under the terms of an EU directive aimed at limiting emissions from coal-fired plants.

Ironbridge, one of two biomass-fuelled plants operated by Eon in the UK, has been given a new lease of life by being converted to run on wood pellets. Even so, the operation is still scheduled to close by 2015.

But as Ironbridge prepares for closure Eggborough Power Station, another big UK coal-fired station based near Selby in Yorkshire, is planning to extend its use of biomass fuel stock that already includes items as exotic as olive pellets and olive cake. These are blended with pulverised coal before it reaches the boilers.

Elsewhere in the UK, a number of smaller-scale biomass ventures are planned.

Renewable energy company Eco2 recently confirmed it had won £128m in financing backing to build a power station in Lincolnshire that will be fuelled by straw and capable of generating enough energy to supply 70,000 households.

And last month the Western Wood Energy Plant near Port Talbot, south Wales, announced further financial backing and supply agreements to support expansion of a biomass burning unit fuelled on virgin and recycled wood waste supplied in part by the UK's Forestry Commission.

Ironically, the drive towards increased co-mingling of coal and biomass and investment in conversion of coal-fired generation units to biomass coincides with a fall in global coal prices.

This has boosted imports of a fuel widely seen as being the least environmentally-friendly feedstock used by electricity suppliers.

But the latest statistics from the Department of Energy and Climate Change also pointed to a year-on-year jump, in the three months to June, of nearly 60 per cent in the contribution that bioenergy made to overall electricity supply. This includes the co-firing of biomass with coal across Britain's fleet of power stations.

In total, renewables' share of the UK's electricity generation increased from 9.7 per cent in the second quarter of 2012, to 15.5 per cent in the April to June 2013.

> Ironically, the drive towards increased use of biomass coincides with a fall in global coal prices

Biomass accounted for two-fifths of this total of 12.8 Terawatt hours supplied to the grid. Wind power contributed half of renewable output, with hydropower, solar, wave and tidal power schemes contributing the remainder.

DECC attributed the jump in bioenergy output last quarter to the conversion of Ironbridge and switch of one Drax unit to biomass, along with the return of Tilbury B power station to operation after a fire.

But Tilbury B, like Ironbridge, has stopped operating, despite its conversion to biomass. Its owner RWE Npower blamed the failure to secure sufficient subsidy to pursue its plan to keep it open for a further 10 to 12 years as a biomass burner.

The eventual scale of take-up of biomass power generation in the UK, then, remains uncertain and subject to the vagaries of government subsidies and guarantees.

But even if there is no hope for the UK to be self-sufficient in production of biomass fuel, proponents argue that there is plenty of feedstock available globally, if not locally, to accommodate a further large move away from fossil fuels, should public policy allow.

Support for biomass power projects is not universal, however.

Plans to expand the UK's use of biomass for electricity generation have been attacked by many environmental campaigners, who have warned of the dangers of overexploitation of forest habitats and possible disruption to local communities in developing countries caused by any switch to commercial biomass crops.

But the UK's Back Biomass Campaign, supported by the Renewable Energy Association, defends the green credentials of imported biomass fuel stock.

It argues that, if properly culled and processed at source, the shipping of biomass in large volumes can be equally carbon-efficient as transporting dispersed, locally produced biomass material by truck to generator plants.

However, with both Ironbridge and Tilbury set for closure, Drax and Eggborough are set to emerge as the two champions of large-scale biomass generation.

The driver of any further expansion of biomass as a renewable energy source in the UK would appear to depend on further encouragement – and subsidy – from government.

Contributors »

Guy Chazan
Energy Editor

Pilita Clark
Environment Correspondent

Ed Crooks
US Energy Editor

Michael Kavanagh
Energy Reporter

Ajay Makan
Oil & Gas Correspondent

Sylvia Pfeifer
Energy Special Correspondent

Paul Breeze
Freelance Energy Writer

Andrew Baxter
Commissioning editor

Chris Lawson, Andy Mears
Pictures

Steven Bird
Designer

For advertising details, contact: **Liam Sweeney**, tel +44 (0)20 7873 4148, email liam.sweeney@ft.com, or your usual FT representative.

Energy

Demand will be driven by China and India

Black power: a coal-fired plant near Datong, China – the country's future coal consumption is hard to predict Corbis

Coal The fuel still accounts for the largest share of power generation but analysts differ over whether the peak is in sight, writes *Sylvia Pfeifer*

For most of the past decade, one of the most widely held assumptions in the energy world has been that demand for coal will keep on rising, fuelled by China's soaring thirst for power as its population leaves the countryside for the cities in large numbers.

International coal prices duly rose and stimulated mining activity across Australia, Indonesia and as far away as Colombia and South Africa. The International Energy Agency (IEA) last year predicted that coal would rival oil as the world's top source of energy by 2017 if no changes were made to government policies; global coal consumption would be 4.32bn tonnes of oil equivalent by that year, compared with around 4.4bn tonnes of oil equivalent for oil, according to its projections.

Yet more recently there have been signs that King Coal's rise may not be as relentless as predicted. While there is a general consensus that demand for thermal coal, used in power generation, is slowing, there are a growing number of market watchers who suggest that demand may peak as early as the next decade.

They point to several factors, from a slowdown in China's economy to competition from shale gas and stringent environmental regulations that discourage investment in coal-fired power plants. Only real progress in carbon capture and storage technology will secure the long-term future for coal, they say.

"The window for profitable investment in coal mining is closing," said analysts from Goldman Sachs in July.

Coal currently enjoys a position at the top of the global fuel mix with a 36 per cent share of electricity generation – ahead of gas with 23 per cent, hydro at 16 per cent and nuclear at 13 per cent – thanks partly to China becoming the world's largest importer of the fuel. However, the analysts said that a sharp deceleration in seaborne demand had moved the market into oversupply and led to lower prices for thermal coal. As a result, "earning a return on incremental investment in thermal coal mining and infrastructure is becoming increasingly difficult", they said.

Analysts at Citi take a similarly bearish view, arguing that Chinese demand for thermal coal in power generation could peak even before 2020, because of slowing domestic economic growth, robust growth in the country's renewables and nuclear capacity, along with efficiency improvements in coal power plants and energy demand in an effort to control air pollution.

There is, however, an opposing camp that argues just as strongly that predictions of coal's demise are exaggerated and that demand will not stop growing.

"We think the idea of peak coal is a myth," says Andy Roberts, principal analyst for thermal coal at Wood Mackenzie, the consultancy.

One point everyone does agree on is that events in China, which accounts for half the world's consumption of coal, will to a large extent determine what happens to demand.

"The notion of peak demand for thermal coal having been reached is not a crazy idea," concedes Laszlo Varro, head of the IEA's gas, coal and power division. "We do see a significant slowdown in demand growth," he adds.

The agency's baseline scenario shows Chinese coal demand and consumption continuing to grow, albeit at a slower pace than in the past decade. Yet Mr Varro identifies two risks: a slowdown in China's economy; and/or a significant change in its energy consumption away from coal towards low-carbon sources.

"China is throwing the kitchen sink at diversifying its energy sources. It is spending five times what the French did at the peak on a new nuclear programme; and eight times what the Germans spent at the peak on wind energy," says Mr Varro.

Another factor impacting coal demand is the shale gas revolution in the US, the second largest user of coal today. Last year, US gas prices fell to a 10-year low, prompting many utilities to switch from burning coal to gas. This year, a rebound in gas prices has seen a modest revival in coal use, although electricity from new coal plants is still expected to be about 50 per cent dearer than from new gas plants. America's Environmental Protection Agency in September promised new rules to limit carbon dioxide emissions from power plants.

The IEA assumes "a slow decline in consumption" in the US, but "if you combine the threat of shale gas and the US finally adopting climate policies, then there could be an acceleration of the decline," adds Mr Varro.

As a result of a shrinking domestic market, coal companies have shifted much of their product to the export market over the past two years. More US coal has been going to Europe, where low carbon dioxide prices and high gas prices have increased the competitiveness of coal in power generation.

> 'Coal is so cheap and abundant, you need a strong, dedicated climate policy with a high carbon price to defeat it'

"In the UK, the clean dark spread – the profit margin from burning coal and selling the resultant electricity – has more than doubled over the past two years from £10 per megawatt/hour to more than £20 per MW/hour in early 2013," says Robert Coates, utilities analyst at Citi in London.

Most experts believe this trend will not last over the long term, especially as many of Europe's older coal plants are due to close by 2015 under the EU's Large Combustion Plant Directive and in view of increasing renewable generation.

Another big player is India, which desperately needs more coal to boost power generation and is predicted by some experts to overtake the US to become the world's second biggest importer.

Those bullish on coal argue that the recent fall in coal prices – with heavy investment in new production by the mining industry in recent years for export projects and China's domestic industry investing in production – will reinforce the attractiveness of the fuel.

"Coal is so cheap and abundant, you need a strong, dedicated climate policy with a high carbon price to defeat it," says the IEA's Mr Varro.

But it is China, experts say, that most defines coal's future. Some predict that the country, with its increasingly restrictive policies, may no longer be a net importer in the next few years.

Others, yet again, argue that even if China experienced slower growth, it would still help underpin demand growth for coal.

"The two big demand drivers are China and India. Change in coal consumption in the rest of the world is noise compared with how much consumption will grow in these two countries," says Mr Roberts.

Power-hungry industries warm to do-it-yourself

Distributed energy

A dedicated plant can reduce costs or improve supply if grids are unreliable, writes *Paul Breeze*

Paper mills soak up power

Energy-intensive industries have a long tradition of using dedicated production plants to meet their power needs.

The oil, paper and chemicals industries are some of the biggest energy users and companies such as BASF, the German chemical concern, often have energy plants at their sites around the world.

Often, the main demand at these industrial sites is for high-quality heat and steam that was traditionally produced in dedicated boilers. However, the modern energy landscape offers options that supply energy both more efficiently and more cheaply, such as replacing the heat-producing boilers with gas-turbine-based electricity and heat generating facilities.

"Customers are becoming more aware of the cost of energy," says Fraser Blunt, director of cogeneration at Npower Cogen, a subsidiary of Germany's RWE.

A combined heat and power (CHP) plant offers higher efficiency by using waste heat from the electricity production to create steam. A good quality scheme should cut energy costs by 10 per cent.

However, many industrial sites require steam at different temperatures and pressures and operating an industrial CHP plant can become complex, particularly where a steam turbine is added to turn any unused steam into more electricity.

Large companies may opt to build and operate their own CHP plants. Others may balk at the prospect.

This is where companies such as Npower Cogen can step in, building, owning and operating the plant for the industrial customer, which takes the energy under a long-term power purchase agreement (PPA). However, for this to work, the company will have to be prepared to sign a PPA that may last 25 years.

An industrial CHP plant will generally be designed to meet the heat demands of the site. This may lead to surplus electricity that can be sold. More complex arrangements are possible in which the industrial CHP plant offers grid support services in return for a fee from the grid operator.

"You could turn the CHP plant off and import power from the grid – overnight, for example, when wind power exceeds demand," says Mr Blunt.

Financial savings from more efficient use of energy offer one incentive to install a dedicated power plant.

Grid stability, or the lack of it, offers another. APR Energy, which specialises in providing blocks of power generating capacity, primarily in developing markets, recently contracted to provide power to the Escobal silver mine in Guatemala.

John Campion, chief executive of APR Energy, says: "The company had used the grid, but power fluctuated so much, it decided on a dedicated power plant."

> Modern electronic devices are much more sensitive to the quality of power

In this case, the dedicated power plant, based on diesel generating sets, will provide power alone. The mining company believes it is a cost-effective way of maintaining energy security.

However, Mr Campion stresses that grid stability is becoming a problem everywhere. This is not just because grids are becoming more unstable, but also because the modern electronic devices that underpin many industries are much more sensitive to the quality of power from the grid than was the case 30 years ago.

It is not only industry that is affected. Smaller commercial organisations may also decide to install some form of primary or back-up supply.

In Germany, where there have been rising grid stability problems, anecdotal evidence suggests that the installation of dedicated power sources is becoming more common.

Meanwhile many homes being built in the US are fitted with back-up generators and this practice is starting to appear in Europe, too.

Even when supply stability is not the issue, there may be simple economic arguments for generating electricity rather than purchasing it from the grid.

In the US the sharp fall in the cost of natural gas following the arrival of shale gas means that in some cases it can be cheaper to generate electricity than to purchase it from the grid.

Meanwhile, as the German situation exemplifies, a failure to invest in grid infrastructure or simply a lack of generating capacity – as is being predicted for the UK in the middle of the decade – could also lead to greater use of distributed generation.

One of the industries that is beginning to capitalise on this situation is solar. While solar generation is most closely associated with domestic rooftop installations, there is potential for much larger dedicated solar power plants.

A big solar facility occupies a large area, so the pioneers are companies that have such space available.

In the UK, the supermarket chain J Sainsbury has plans to place panels on all its stores, while competitor Morrison has installed 1MW of solar capacity on its distribution centre in Bridgwater, Somerset and 2MW at Sittingbourne, Kent.

The cost of solar panels has fallen significantly in the past two to three years, making them increasingly cost effective.

"Solar will continue to be an attractive option," says James Armstrong, managing partner at Bluefield Partners, an investment manager that specialises in solar investment.

Unlike CHP, a solar photovoltaic installation is relatively simple to manage and many companies will opt to own and operate their own facilities.

However, there is an alternative route, exemplified by that being proposed by Bluefield.

The partnership has raised funding to purchase or build a number of large solar plants which are operated on behalf of clients such as Toyota and Thames Water. The clients take power under long-term PPAs.

"This is an underused model so far," says Mr Armstrong.

FINANCIAL TIMES
NON-EXECUTIVE DIRECTORS' CLUB

Non-Executive Directors in the Oil and Gas Sector

Risk, Governance and the Role of the Non-Executive

Wednesday 23 October 2013

Whether you are already a non-executive director working in this sector or just thinking about taking up a role, this workshop will help you to make sure you are on top of what you really need to know about finance, the regulatory environment, risk, and protecting your reputation.

Chaired by portfolio non-executive director and chairman David McManus, and led by Jon Fitzpatrick of Cenkos and Kevin Davidson of Maxwell Drummond, the event will draw on the collective experience of a wealth of industry specialists.

Topics

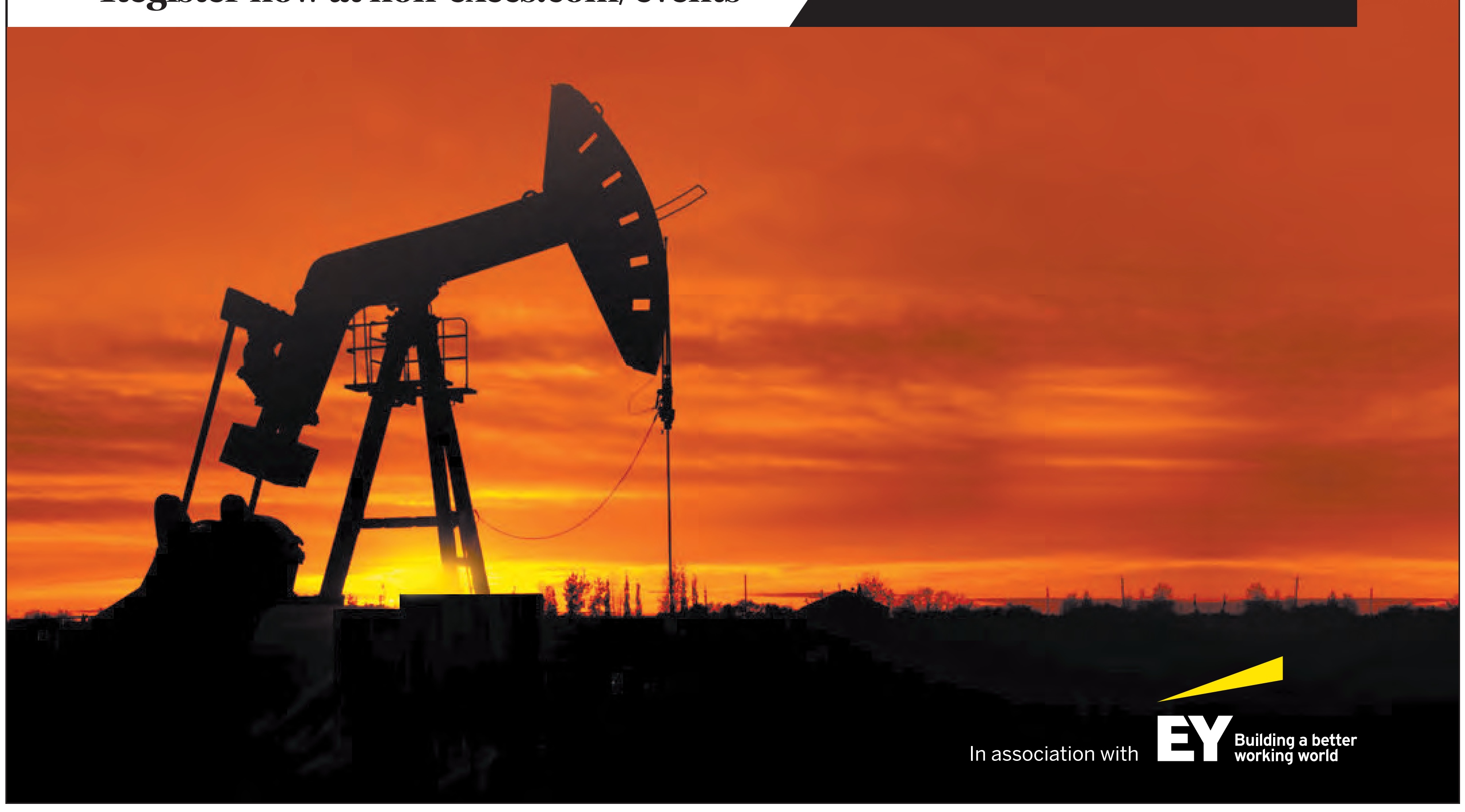
- Finance, Audit, Impairments
- Regulation
- Risk, Reward and Board Selection
- Risk and Reputation
- An Investor's Perspective
- Chairmen's Panel

This workshop will include a light lunch and a networking drinks reception.

Time: 09.00 - 18.15 *followed by networking drinks reception*
Venue: Financial Times, London
Price: Non-member fee £717 (inc VAT) Member fee £654 (inc VAT)
Become a member today and save £60 +VAT off this seminar

Attendance counts as 8 CPD hours of structured learning.

Register now at non-execs.com/events



In association with EY Building a better working world

Energy is only the first link in our value chain

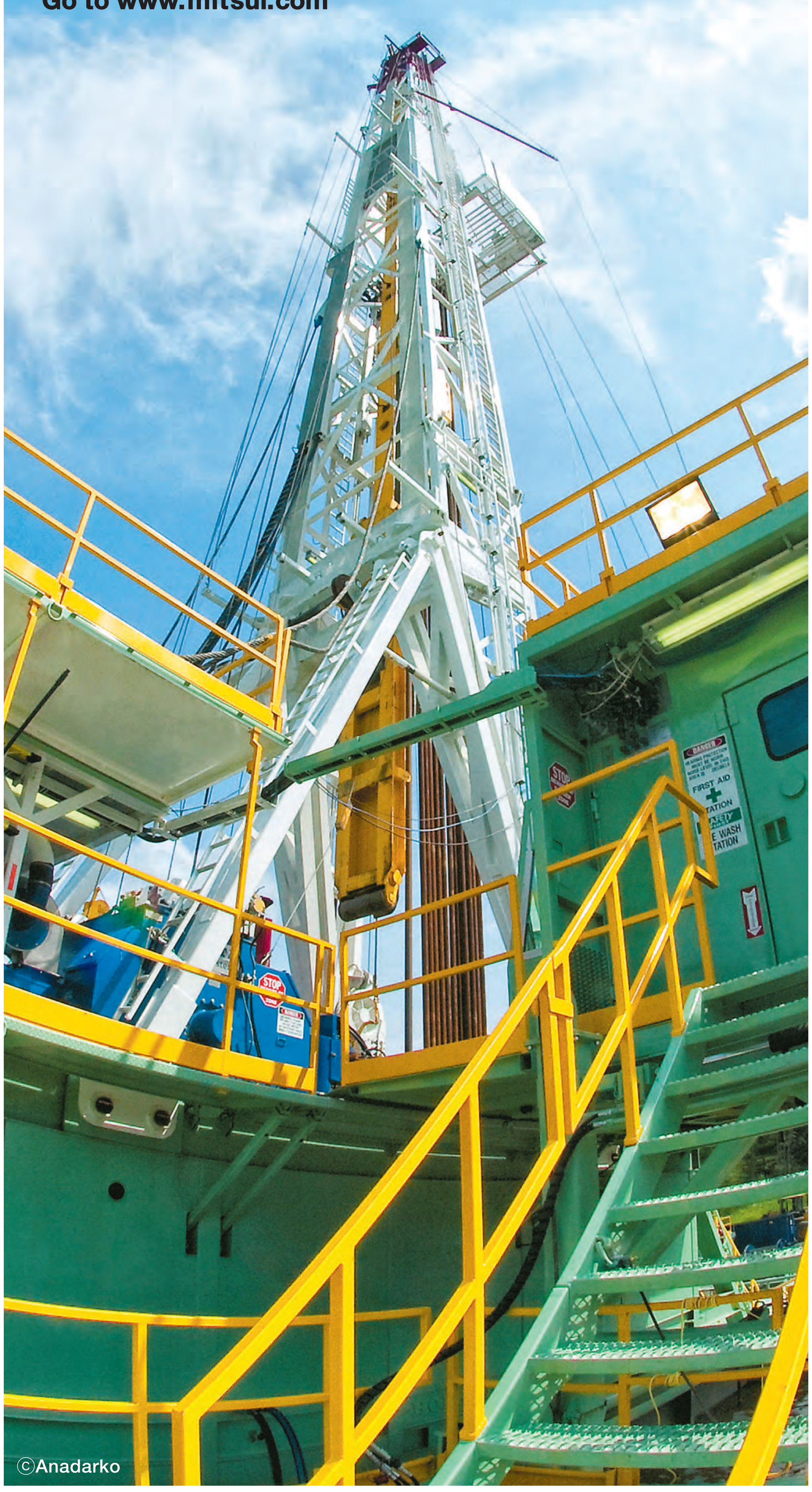
The shale revolution in the United States has transformed the world energy map—but shale gas itself is only the beginning.

At Mitsui & Co., we're combining our wide-ranging capabilities with the technical know-how of joint venture partners to build a natural gas value chain that covers everything from gas production, distribution and export to the manufacturing and marketing of petrochemicals and gas chemicals.

The possibilities are endless, but our goal is simple: to create a more connected and prosperous world.

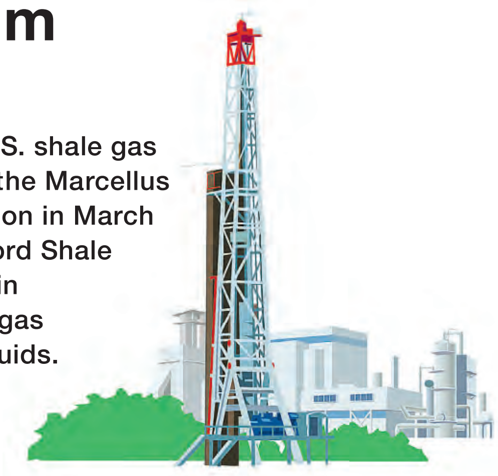
After all, isn't that what every revolution should be about?

Go to www.mitsui.com



Acquiring upstream assets

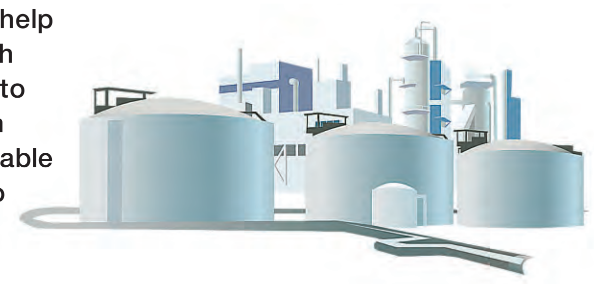
Mitsui was quick to secure top-quality U.S. shale gas assets. We acquired a 15.5% interest in the Marcellus Shale project from Anadarko for $1.4 billion in March 2010 and a 12.5% interest in the Eagle Ford Shale project from SM Energy for $680 million in December 2011. Marcellus produces dry gas while Eagle Ford is rich in natural gas liquids.



Drill Rig, Marcellus Shale, Pennsylvania

Boosting Asia's energy security

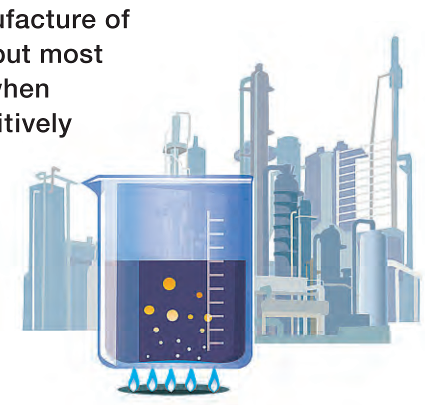
Mitsui is actively seeking new sources of liquefied natural gas (LNG) worldwide to help reinforce the energy security of Asia. With partner Sempra Energy, we are planning to add liquefaction facilities to the Cameron LNG receiving terminal. Cameron will be able to export 12 million metric tons of LNG to Asia and other markets annually.



Cameron LNG Terminal, Louisiana

Bringing U.S. manufacturing home

Methanol is a key raw material in the manufacture of adhesives, plastics and pharmaceuticals, but most U.S. methanol production moved abroad when natural gas prices were high. With competitively priced U.S. natural gas, that situation has been reversed. The plant Mitsui and Celanese Corporation are constructing will cover around 20% of total U.S. methanol demand.



Methanol Plant, Clear Lake, Texas

Adding value through technology

Alpha olefins (AO) are ethylene-based chemical products used as raw materials or co-monomers to enhance the performance of everyday products like synthetic engine oils, plastics, detergents and paper. Together with AO technology leader Idemitsu Kosan, Mitsui is planning to construct an AO plant on the U.S. Gulf Coast to serve the world's growing appetite for these key applications.

Alpha Olefins Plant, The U.S. Gulf Coast

Reducing chemical production costs

The chlor-alkali plant Mitsui and The Dow Chemical Company are currently building will manufacture caustic soda and chlorine. When combined with ethylene, chlorine produces EDC, a key ingredient for PVC, which is much in demand to make water pipes for developing countries. Thanks to shale, our plant benefits from competitively priced gas-generated electricity and ethylene.

Chlor-Alkali Plant, Freeport, Texas

CHALLENGE & INNOVATION

MITSUI & CO., LTD.

www.mitsui.com