OIL & GAS

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Industry thrown into turmoil

Japan's nuclear emergency and Middle East events cast doubt on global energy policy, writes **Sylvia Pfeifer**

Far-reaching consequences: the effects of the Fukushima incident on the nuclear and wider energy landscape are already being felt in global energy prices and policies AFP

Next month the world will mark the 25th anniversary of Chernobyl, the nuclear industry's worst disaster. The catastrophic accident halted the development of new reactors in much of the world for more than two decades.

Over the past 10 days, the world's eyes have been watching another nuclear crisis unfold, this one not in eastern Europe but in Japan.

Experts say the events are not on the same level as those in Chernobyl, but the ramifications for the nuclear industry and the global energy landscape will be far-reaching.

Events in the Middle East, in particular Libya, are also affecting the industry.

Governments around the world are reviewing their plans for nuclear power, most notably in China, which had been spearheading a revival that had gathered pace over the past decade.

Faced with ambitious climate change targets, many governments, especially in the developed world, had embraced low-carbon atomic power as a key element in any future energy mix.

That renaissance is now stuck in its tracks, even if only temporarily, as governments review the safety of their reactors.

While the nuclear industry faces, at best, substantial delays to its plans as well as the burden of much higher costs, there are also likely to be repercussions for other forms of generation such as renewables and gas.

Both will be required to make up any shortfall resulting from any material delays to new reactors.

Nobuo Tanaka, the chief executive of the International Energy Agency, the rich nations' energy watchdog, warned last week that the role of nuclear power in global energy supply may be less than previously forecast, following the events in Japan.

"Building nuclear power or expanding nuclear power may mean more costs or more delay," he said. "That means the nuclear option may not play as big a role as we predicted."

The IEA last year forecast that demand for nuclear energy would rise from 6 per cent in 2008 to 8 per cent in 2035.

The short-term effect has already been felt by the energy markets, with prices for oil and gas soaring as Japan has been forced to import fossil fuels to replace the lost nuclear output.

The cost of gas and coal, the two main alternative commodities for electricity generation, have already risen sharply.

Royal Dutch Shell, Europe's second-largest oil and gas company, said last week it was in talks with Japan to provide it with additional cargoes of liquefied natural gas.

"Non-fossil fuels have been hit with two body blows: this nuclear disaster and the price of natural gas, which is completely eroding the economic competitiveness of alternatives," says Robin West, chairman of PFC Energy, a consultancy.

"A third blow is the fact that governments will find it difficult to subsidise alternatives or force high feed-in tariffs, given the new economic realities. Gas is a big winner, and the life of coal will be extended," he predicts.

Countries rich in gas, such as Qatar, where Shell, for example, is building mammoth LNG projects, are seen as key beneficiaries from a stronger demand for gas. Australia, where several

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Inside this issue

Companies feel effects of Macondo disaster

Gulf of Mexico

Sheila McNulty finds that it will never again be business as usual

When US regulators approved in February the first deepwater drilling permit since BP's Macondo disaster last April, the industry dismissed it as a political gesture aimed at quieting calls from Congress to resume drilling. Unrest in north Africa and the Middle East was pushing up oil prices. And the public was already seeing higher prices at the petrol pump.

However, Michael Bromwich, head of the Bureau of Ocean Energy Management Regulation and Enforcement, said politics had not been a factor. Noble Energy had simply met all the requirements for a permit.

Yet the reality was that Noble did not have to do everything now being required by regulators to get a new permit; it had been drilling when Macondo happened and only needed clearance to finish its job. No permits for new projects have been issued.

"The deepwater drilling moratorium has been lifted in name only," said John Hess, chairman and chief executive of Hess.

And the industry does not see rising oil prices changing that.

Andy Steinhubl, partner in the Houston office of Bain & Company, the consultancy, notes pressure on regulators to permit new deepwater drilling has been high for some time because of the economic downtown, high unemployment and growing financial pressure on drilling companies from lost work. Seahawk Drilling has already filed for bankruptcy, citing the drilling ban.

"The administration has been sticking to their principles. They're not stalling. There was a lot to work through and they're working through it," Mr Steinhubl said. "I don't see this [north Africa/Middle East] crisis as accelerating that timetable."

Yet the industry is impatient. Companies such as Chevron had been counting on new projects in the gulf to increase production in coming years. And while they are still hopeful, with most companies on standby, oil companies believe they are being held to a much higher standard than any other industry. The constant refrain is that when there is an aircraft crash, the US does not ground all aircraft.

Yet the reality is that regulators have come under so much criticism for being what Mr Bromwich calls a "permitting mill" before Macondo, that they are going to do everything to change that reputation.

Companies complain that permit applications are repeatedly kicked back by regulators, who are asking for more information, and that they need a clear template for what is needed. Regulators have yet to come up with one.

Mr Bromwich says regulators were working on a number of improvements to strengthen oversight, given that they had simply failed to keep pace with the transformation of the offshore drilling industry as it moved into deeper water.

He points out these things take time, noting that UK activity dropped off substantially for two years after the Piper Alpha accident there and almost came to a standstill. "We have a new normal; it's going to take more time than in the past," he says.

Kurt Hallead, co-head of global energy research at RBC Capital Markets, is among those who sees the Noble permit as a positive sign.

"We're going from a standstill to some movement," he said. And, despite all the threats to leave the region if the deepwater drilling ban went on too long, the majors remain keen to get back out there. He adds: "The major oil companies view the Gulf of Mexico as a world-class oil-producing region. They have every intent to continue to invest there."

John Parry, principal energy analyst at consultancy IHS, says he expects offshore contract drillers to see increased demand for their newer, more technologically advanced rigs.

> 'Once the dust settles and the rules become clear again, most deepwater players will go back'

And competition between operators will surely drop, as smaller companies move to leave the gulf, given the liability of operating there demonstrated by Macondo.

These are both attractive reasons for those with deep enough pockets to wait patiently on the sidelines for permit granting to resume.

"The US cannot afford to shut down one of its key sources of energy supply," said Rodolfo Guzman, director at Arthur D Little, the consultancy. "Once the dust settles, and the rules become clear again, most deepwater players will go back." However, the region will never again be seen as business as usual.

Many companies insist that least some of the changes afoot in the US – such as the requirement of adequate spill response systems – should be duplicated around the world the better to safeguard deepwater drilling from Africa to Brazil.

Bob Dudley, BP's chief executive, says it is working to spread the lessons learnt from the disaster. "We believe we have a responsibility to share our learning with those who can benefit from it – including our competitors, partners, governments, regulators," he says.

He adds: "Indeed, we have been asked by people around the world to explain what we have learnt. BP executives have travelled to Angola, Russia, Australia, Brazil and elsewhere in recent months, bringing our learnings to stakeholders, industry partners, academic and governments."

Cleaning the beaches: 5m barrels of oil spilled after the Deepwater Horizon explosion last year Bloomberg

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North Sea Opportunities west of Shetland

The North Sea is officially back. Last year saw a development surge with $13.8bn of projects approved by the UK government.

This resurgence was exemplified in the run-up to Christmas in the most unlikely of places: Dundee City Council website.

The webcam for the centre of this city on Scotland's east coast kept crashing, as thousands of eager retail investors logged-in to catch a real-time glimpse of Galaxy II, a jackup rig waiting to be dispatched northwards to a position 110 miles off Aberdeen.

Its target was Catcher, an estimated 100m barrel field of the kind long thought to have been depleted. The companies involved in the project are hardly household names.

Apart from FTSE 250 Premier Oil, there is Encore – which contracted the rig to examine the Catcher field further – Wintershall, Nautical Petroleum and Agora Oil, all Aim-traded companies that have proliferated in the area, snapping up unwanted assets by bigger companies.

In February, BP announced plans to sell its ageing oil and gas fields in Britain. The UK assets being sold are valued at about $1bn and produce 40,000 barrels of oil equivalent a day, 15 per cent of BP's UK production.

"With the high oil price, snapping up these assets is bread and butter acquisition activity," says Keith Morris, an analyst at Evolution Securities, an investment bank.

Apart from one-offs, such as Catcher, exploration opportunities in the North Sea are generally limited. So more consolidation is expected. Ithaca Energy, which produces 5,500 boe/d from its North Sea fields and bought GDF Suez's North Sea assets last year, recently secured a $140m lending facility in part for more acquisitions.

"We're looking to acquire; we're in an M&A cycle. There are a lot of small companies that want to monetise what they've done, while there are others looking to absorb. So, it's a really vibrant commercial atmosphere," says Nick Muir, Ithaca's chief exploration officer.

Despite the success of independent companies – which has created a dedicated retail investor following – foreign giants have moved the North Sea back into the limelight.

Last summer, Dana Petroleum purchased £270m ($398m) of Dutch North Sea assets, producing 16,000 boe/d, from Canada's Suncor Energy.

KazMunaigas, Khazakhstan's state-oil company, made its first foreign purchase when it bought a $30m 35 per cent stake in BG Group's White Bear prospect in the central North Sea.

Korea National Oil Corporation (KNOC) then acquired Dana in a £1.9bn ($2.88bn) hostile bid. KNOC wanted Dana's North Sea oil to help double its production to 300,000 b/d.

"National oil companies, particularly those from Asia, will continue to be acquisitive [this year]," says Ian Sperling-Tyler, head of oil and gas corporate finance at Deloitte.

"During 2010, companies held cash on their balance sheets to cover risk. With risk declining, it is now being put to work in pursuit of acquisition opportunities, including assets being sold by the supermajors."

In truth there are two North Seas. The traditional sphere – composed of northern, central and southern areas – is the focus of independents' recent activity and mostly contains mature fields. Then there is the area west of the Shetland Islands.

"People are waking up to West of Shetlands. Profits are being recycled in exploration and suddenly it's become somewhere [where companies] realise they can make a lot of money," says Peter Hitchens, an analyst at Panmure Gordon, the stockbroking and investment banking group.

Indeed, as big companies left the Gulf of Mexico following the Macondo disaster last spring several have taken the deepwater technology pioneered there to exploit opportunities elsewhere.

> In return for subsidies now, the government stands to gain up to 600,000 b/d

That is part of the reason why the UK government last year announced a tax allowance worth up to £160m ($256m) per field to help catalyse development.

On the gas side, France's Total received regulatory approval for its Laggan and Tormore gas fields last year, a £2bn ($3.2bn) development that would bring gas to a processing plant on the Shetland Islands by 2014 and then into the UK grid.

The hope is that, once the infrastructure is in place, more modest discoveries could be tied in cheaply.

Nevertheless, despite near record oil prices, there is a shortfall in funding to develop what Hannon Westwood, an oil and gas consultancy, estimates are 2.6bn boe held in "near-term" developments. Jim Hannon, who co-founded the consultancy with Charles Westwood, says the government will need to provide funding of $8bn to $18bn to secure long-term UK oil supply.

"All of those barrels are capable of being brought onstream over the next five years but are held back by the tax regime and a lack of capital provision from markets.

"In return for subsidies now, the government stands to gain up to 600,000 b/d in extra production and a potential $44bn in extra tax revenue."

Christopher Thompson

Ice thaws on Canadian projects

Oil sands

With the price of crude three times what it was two years ago, the economics start to make sense, says **Ed Crooks**

At the trough of the last oil price cycle two years ago, with crude briefly below $33 a barrel, the Canadian oil sands – "tar sands" to their opponents – seemed in danger of being written off as a failed experiment.

Construction costs for new projects had soared, as a consequence of trying to bring too much investment into a constrained area around the hub of the oil sands – Fort McMurray in Alberta.

While existing projects that had sunk their start-up costs long ago – the earliest goes back to the 1960s – were still commercially viable, new projects that had to put in place expensive facilities seemed utterly uneconomic. Some were said to need oil prices of $90 a barrel or more to show a profit.

The International Energy Agency, the watchdog backed by rich country governments, reported in 2009 that 15 planned developments in the Canadian oil sands had been put on ice, as a result of the economic downturn and the collapse in the price of crude.

There were signs, too, that the hiatus could be prolonged.

Plant at Fort McMurray in Alberta, the centre of the oil sands industry Jiri Rezac

Peter Voser, the chief executive of Royal Dutch Shell, which had been one of the most enthusiastic investors, told the Financial Times early in 2010 that the company's expansion in the region would be "very much slower", once its latest investment phase was over, as the group made a strategic shift away from high-cost "unconventional" oil.

Today, with the price of US crude three times that low of two years ago, the outlook for the Canadian industry looks brighter.

Without much fanfare, projects that were already under way when the downturn hit are coming to completion, and projects that were put on ice are being warmed up again.

Analysts at IHS Cera, the research group, estimate that at the height of the boom, in the summer of 2008, there were projects planned or already under way to add 2m barrels a day of production to last year's total of about 1.4m-1.5m b/d. Today, those projects that are set to go ahead will add about 1.5m b/d, suggesting that only about a quarter of previously planned investment remains on hold.

After a couple of years of being embarrassed to talk to their investors about their Canadian commitments, leading international oil companies are once again promoting them as a source of strength.

ExxonMobil, the world's largest private sector oil company by market capitalisation, has faced concerns that it is becoming excessively reliant on low-value US gas, following its $41bn acquisition of Texas-based XTO. It is answering that criticism in part by pointing to its Kearl oil sands project, which is due to come into production by the end of 2012.

Even Shell, which has its costly expansion of its Athabasca Oil Sands Project coming onstream this year, looks likely to commit itself to further investment in "debottlenecking" the project: installing new equipment to make maximum use of capacity.

The expansion is adding 100,000 b/d of production to take output to 255,000 b/d; the first phase of debottlenecking will add a further 35,000 b/d.

Shell's move to spend its money more carefully on lower-cost adjustments to existing projects, rather than a grandiose development, is typical of the industry's new approach.

The revival of the oil sands is being driven not only by the upturn in oil prices, but also by a smarter attitude to costs.

Fort McMurray remains a very expensive region in which to operate, but companies are now doing more to get round that problem.

"The industry has realised there is a limit to how much new capacity it can bring on at once," says Jackie Forrest, the Calgary-based director of global oil at IHS Cera.

"Today we are seeing an upturn in investment in projects where the break-even oil price is about $60-$70 per barrel. So the economics make sense."

Among the examples of this new carefulness about costs, she says, have been decisions over upgraders, the expensive facilities needed to convert the sludgy bitumen extracted from the oil sands into a saleable form of crude.

At one point, as many as eight of these multibillion-dollar upgraders had been proposed, and five looked likely to go ahead. Now just two such projects are under development.

Last December, Suncor of Canada and Total of France agreed a deal that reflected this new spirit, pooling operations in a range of oil sands developments and in Suncor's planned Voyageur upgrader.

A joint venture between Britain's BP and Husky Energy of Canada is another example. In 2007, Husky abandoned its plan for an upgrader, and signed up for a joint venture with BP that will pipe the bitumen (diluted with lighter liquids so it will flow) to the British company's Toledo refinery in Ohio, to be processed into fuels there.

With the economics looking more favourable, environmental arguments may now return to the fore.

Opponents of tar sands development, who had hoped market forces would remove the need for their efforts, seem likely to be disappointed.

Industry thrown into turmoil

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big LNG projects are under construction, could be a winner in the longer-term, if nuclear programmes are severely delayed, said one oil and gas analyst. BG Group last October announced plans for a $15bn LNG project in Queensland.

For the world's international oil and gas groups all this is good news. Many of them are sitting on strong balance sheets and growing cash piles, underpinned by the current high oil price environment.

Yet the challenge remains of delivering sustainable growth in exploration and production – and proving this to the market – and that means getting access to new reserves.

The supermajors have all announced increases in their exploration budgets in recent months, but analysts also expect more deals this year.

Bob Dudley, chief executive of BP, has led the way, striking two strategic alliances in quick succession since the start of the year, as he tries to rebuild the UK oil group after last year's Gulf of Mexico accident.

Both deals give BP access to potentially big reserves: a $16bn share swap with Rosneft, the Russian oil champion, coupled with an alliance to explore in the oil-rich seas of the Arctic; and a $7.2bn thrust into India by taking 30 per cent stakes in natural gas blocks controlled by Reliance Industries.

Both deals hold out the potential for huge reserves and both the Russian Arctic and the deep water off the east coast of India could one day become an important contributor to BP's profits.

Both also underline the gradual shift of power between the international oil companies and their national oil company (NOC) peers, whose countries hold the majority of the world's reserves.

Most of the supermajors, have recently announced some form of alliance with a national oil company,

> Most supermajors have announced some alliance with a national oil company

although BP is so far the only one to have agreed a substantial share swap.

Philip Lambert of Lambert Energy Advisory, which advised BP on the Rosneft transaction, told the Financial Times in January, when the deal was announced, that partnerships were the way forward.

"National oil companies still want the technology of the international majors, but by itself this is not sufficient to get sustainable access. It needs to be a proper partnership," he said.

Many national oil companies (NOCs), notably China's, are also becoming an increasing force to be reckoned with outside their own countries. A number of Chinese companies, including PetroChina, have announced overseas acquisitions in recent months, several of them focused on unconventional shale gas.

"The NOCs accounted for 20 per cent of the mergers and acquisitions market in upstream oil and gas last year," said Robert Plummer, senior analyst at Wood Mackenzie, the oil and gas consultancy. "Ten years ago, they barely participated on the market."

According to Mr Plummer, some of the NOCs are "now investing capital in the upstream oil and gas sector at a rate above that of the majors, especially when considered on investment per barrel produced".

Most analysts argue that, for now, both sides need each other, but no one is ruling out a time when the NOCs may hold the upper hand.

There are also other risks. The unrest in the Middle East, in Egypt, and Libya in particular, has underlined the scale of the political risk companies face in their search for more reserves.

BP had been preparing to drill in the deepwater off Libya before the recent crisis erupted, but those plans are now on hold. Shell has had to stop its exploration activities in Libya for the time being.

Peter Voser, chief executive of Shell, last week said it was too early to predict the impact of events in the Middle East and in Japan, both for the company and the rest of the industry.

However, he conceded that they were "a clear reminder" that such developments can affect the oil markets.

"We are living in a very interdependent world."

Huge prize lies under a pristine wilderness

Arctic frontier

With nearly a quarter of the world's untapped reserves, revenues could transform local economies, writes **Sylvia Pfeifer**

Russia's first offshore gas development: the Sakhalin II oil and gas project in the sub-Arctic Sea of Okhotsk has a huge liquefied natural gas plant

Bob Dudley, BP's chief executive, knows the perils of doing business in Russia.

When he was head of TNK-BP, the oil company's 50:50 joint venture with a group of Russian billionaires, he was embroiled in a shareholder dispute and had to leave the country after authorities refused to renew his visa.

That furore died down, but less than three years later Mr Dudley is again rattling his partners. There is a huge prize at stake – the untapped oil reserves that lie under Russia's Arctic waters.

To secure access to those riches, Mr Dudley struck an ambitious deal in January, agreeing to a $16bn share swap with Rosneft, the Russian state oil company, and to collaborate on exploration of the Arctic.

BP's Russian partners in TNK-BP say the alliance breaks their shareholder agreement with the UK group. BP disagrees.

The dispute is now in the hands of an arbitration court and BP's share swap with Rosneft is on hold.

The stakes for BP and Mr Dudley are high.

In order to rebuild BP after last year's tragic accident in the Gulf of Mexico, which has undermined the company's future in the US, it needs to gain access to new reserves and experts believe the waters around the Arctic are one of the world's last and potentially largest untapped hydrocarbon areas.

According to the US Geological Survey (USGS), the area may hold 90bn barrels of recoverable oil – nearly a quarter of the world's unmapped reserves and more than twice that produced by the North Sea since the 1960s. Two-thirds is thought to be in Russia and, although there has been some exploration, so far there has not been any development.

BP is not the only company making a move. From Russia to Alaska and Greenland, a land grab is unfolding in the Arctic.

The potential prize is great, not just for oil companies but also for local economies.

For example, in Greenland, an icy land mass three times the size of Texas but with a population of just 57,000, oil revenues could transform an economy hitherto dominated by fishing.

Wood Mackenzie, the consultancy, estimates there could be 20bn barrels of oil and gas in Greenland. So far only nine wells have been drilled there.

Royal Dutch Shell and Statoil of Norway were last year among a number of companies awarded exploration blocks, joining a host of others, including ExxonMobil and Chevron.

High oil prices are also fuelling the land grab, making even the most expensive projects look worthwhile.

Critics argue that drilling in the Arctic, one of the world's pristine wildernesses, is fraught with risks, from drifting icebergs to hostile weather.

BP's accident in the Gulf of Mexico has only heightened the sensitivity and scrutiny of offshore drilling.

> BP's accident in the Gulf of Mexico has only heightened the sensitivity and scrutiny of offshore drilling

Robert Blaauw, senior adviser on global arctic themes for Shell, which has already been drilling in arctic-style conditions in Sakhalin in Russia, says: "People ask us, why look for oil and gas in the Arctic?"

The reasons, he argues, are clear: with the world's growing population expected to lead to a doubling in demand for energy by 2050, "we need all the credible sources of energy to meet that demand".

"We believe the Arctic holds around 30 per cent of the yet to be found gas and 20 per cent of the yet to be found oil," he adds.

The big oil companies argue they are well aware of the environmental and safety concerns and will tailor their operations towards the special conditions in the Arctic.

As part of its alliance with Rosneft, BP announced that the two companies would set up a technology centre that will work closely with Saint Petersburg university, international research institutes and design bureaus to develop technologies and engineering practices for the "safe extraction" of oil and gas resources from the Arctic shelf.

Exploration in the Arctic, while environmentally contentious, is not regarded as technically difficult in comparison with areas such as the deep waters of the Gulf of Mexico.

Companies will be drilling in shallow waters and there are also relatively few storms.

However, development does pose challenges, not least because drilling can only take place for three months of the year because of the icy conditions – although BP has drilled in ice onshore in Alaska and also offshore in ice-bound conditions in Sakhalin.

Technology is very important, says Mr Blaauw, noting that it is possible to use floating structures and that pipelines can be buried underneath the seabed.

While the potential prize may be great, the time horizons are long and the costs substantial.

There will also be setbacks along the way.

In February, Shell announced it was delaying plans to drill in Alaska by 12 months, amid uncertainty over when it will receive regulatory clearance in the wake of the Gulf of Mexico accident.

The company is five years into 10-year leases in Alaska but its plans have been delayed by environmental concerns and government permit issues, in particular an air quality permit.

There have also been calls for better spill and containment capabilities following the BP accident.

Shale extraction technology leads to oversupplied market

US gas market

Producers pin hopes on exports, but competition is stiff, says **Sheila McNulty**

The breakthrough technology that created the US natural-gas boom has been the industry's undoing.

The market is so swamped with gas that prices are at or below break-even for many producers. And yet the US government is so keen on renewables that it has yet to recognise that supporting a shift to gas from coal and oil would rapidly reduce carbon emissions.

"It's a no-win situation for the industry," said Fidel Gheit, managing director of oil and gas research at Oppenheimer and Co. "We're sitting on a huge amount of gas."

The Japanese earthquake and nuclear disaster have caused a jump in natural gas prices. Japan was already the world's largest buyer of LNG and has been bidding on additional cargoes in recent days.

We do not know what this will mean for demand in the long term but in the meantime some producers are moving to export the fuel in liquefied form.

Macquarie, the Australian bank, and Freeport LNG (liquefied natural gas) propose to retrofit an import terminal to condense and ship the fuel abroad.

The plan, announced in November, follows one outlined by Cheniere Energy for a combined import and export terminal at Sabine Pass, Louisiana.

Nick O'Kane, Macquarie's global head of Energy Markets, said the response from countries it already has permission to export to – those 16 countries with a free-trade agreement with the US – has been "overwhelmingly positive".

"The US offers diversity for LNG buyers," Mr O'Kane says. "And our pricing is attractive." He will not detail what it is, only noting it is based on Henry Hub-based pricing, which has been about $4 per million British thermal units in recent months, since falling from a record of $13.69 per mBtu in 2008.

"We have enough customers who are interested," says Charif Souki, chief executive of Cheniere. The company is working on the final design and long-term export agreements for the project. "With oil so high, there is an enormous market for gas on a global basis. We don't have to 'sell' the reasons for the project to anybody."

Nonetheless, the plans of both companies are being met by much scepticism in the industry, given the billions in investment required to enable gas to be liquefied for export, and competition from other potentially huge LNG export markets.

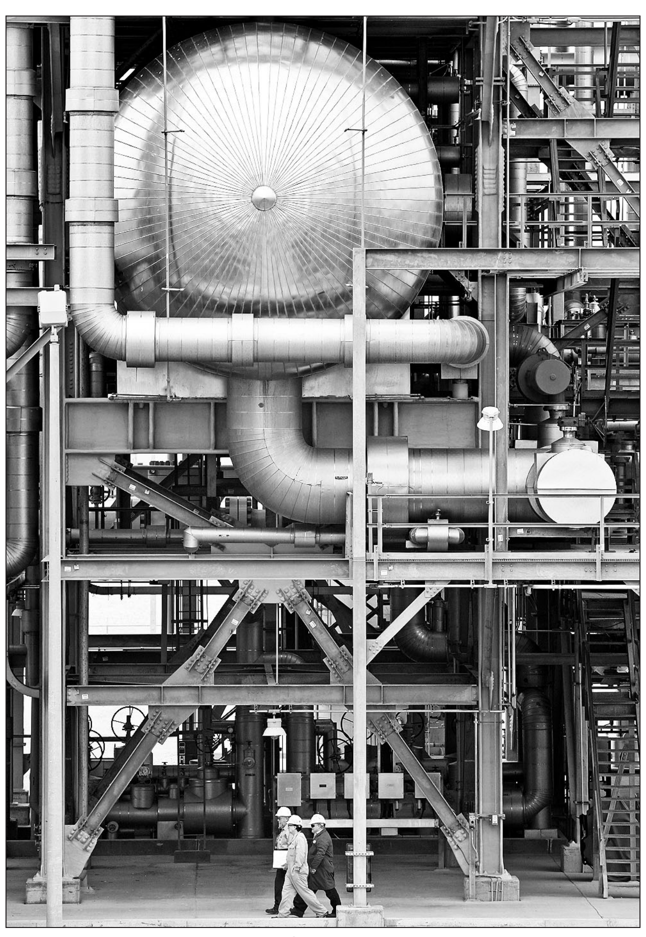
"I don't see a strong push to import US LNG," says Paolo Dutto, associate director with Arthur D Little Energy Practice. He notes that Australia and the Middle East were among those with huge gas resources that were preparing to export LNG. "It will be very hard for the US to compete with other regions."

Particularly, he says, since those countries are closer to Asia, the primary import market and, therefore, cheaper for importing.

> 'With the oil price so high, there is an enormous market for gas globally'

"The long-term economics don't support it," says Andy Steinhubl, Houston partner at Bain & Co.

He believes the US will start using more of its gas with a recovery in the economy, which will promote power use, and the fact that it is cheaper to build gas-fired generating capacity than coal-fired.



Room for expansion: an LNG facility in Texas Bloomberg

That does not mean gas will displace current coal-fired capacity. Even at these low rates, Mr Steinhubl says, gas prices are not low enough to take out existing coal-fired capacity.

It would take much lower gas prices to do that. Nonetheless, he says, a carbon tax would put pressure on the installed coal base. It would take a charge of $35-$50 a metric ton to make it uneconomic to run existing coal.

But Mr Souki insists that in the past 30 years the US has not increased its domestic gas consumption and even if it moves to do so, there will be more than enough gas to fuel the domestic market as well as to be exported. He notes that 33 US states are gas producers and that number might well grow.

Nonetheless, the technology for extracting shale gas that has enabled the US to expand forecasts of supply to more than 100 years' worth at current usage rates will spread abroad.

Foreign energy companies have been buying into the US sector to learn the expertise and technology to take back home.

And while it is unclear just how much shale gas will be developed across the globe, one indication came in a report from IHS Cambridge Energy Research Associates, which said: "The size of European unconventional commercial gas reserves rival that of North America."

It estimates that Europe's total unconventional gas in place could be 173 thousand billion cubic metres.

"The technological revolution in unconventional gas has been the single most important energy innovation so far this century," says Daniel Yergin, IHS CERA Chairman and author of the Pulitzer-Prize winning book *The Prize*.

"Its tremendous potential has already transformed North America's energy landscape and may now transform the global gas industry." If that happens, there will be even more competition for US LNG.

Oil & Gas

Two very different disasters will have profound effects

US energy policy

The administration will struggle to reconcile demand and a range of safety concerns. **Ed Crooks** reports

US energy policy for the coming decade will be shaped by two disasters less than a year apart: the Deepwater Horizon explosion and blow-out in the Gulf of Mexico in April 2010, and the Sendai earthquake and tsunami less than a year later.

The first has led to significant curbs on future supply of fossil fuels in the US; the second is likely to cause a significant increase in demand.

As a consequence, the price of US natural gas is likely to be pushed higher, and the country's reliance on imported oil, which has been falling since 2006, may stop declining, or even rise.

In Washington, the political heat has been centred on the debate over the powers of the Environmental Protection Agency, the government regulator, to control emissions of carbon dioxide and toxic pollutants from power stations.

The outcome of that argument, which divides on broadly party-political lines between Republicans and Democrats, will also be important for shaping the energy landscape of the 2010s.

Yet the most profound influences are likely to be the policy responses to those two very different disasters.

On the supply side, the question will be how far the federal and state authorities allow domestic US oil and gas production to grow.

At the time of writing, just two permits for drilling deepwater wells in the Gulf of Mexico had been awarded by the offshore regulator since Deepwater Horizon.

The slowdown in awarding permits, even after the formal lifting of the moratorium on deepwater drilling last October, appears already to be having an impact on oil production in the gulf, and that drag on output will grow greater with every passing month.

George Kirkland, the head of exploration and production at Chevron, the second-largest US oil company, told the Financial Times that the combined effects of the moratorium and the subsequent "permitorium" – the slow pace of new approvals – had set the company's plans for the development in the gulf back by a full year.

Its deepwater project Jack/St Malo, which is scheduled to come on stream in 2014, will have to begin with less production than was originally planned, because the company will be able to drill fewer wells.

The story of the deepwater slowdown is important for its own sake, and also for what it says about the approach to energy policy in the US.

Faced with a high-profile crisis, the authorities' natural response was to reach for the blunt instrument of regulation, and not to worry too much about the collateral damage to companies working there, or US energy supplies.

The obvious next candidate for such a reaction is the shale gas and oil industry, which extracts resources from regions once thought to be uneconomic, via long horizontal wells, fracturing the rocks by injecting water under higher pressure.

"Fracking", as it is known, has become increasingly controversial, featuring in the Oscar-nominated documentary *Gasland*, and drawing increasingly vocal protests from residents of northern states such as New York and Pennsylvania, where drilling and fracking are either proposed or already under way.

The industry argues that there has not been a single proved case of contamination of groundwater with escaped "fracking fluids" – water and sand mixed with chemical additives.

But just one confirmed incident could deal a huge blow to an industry that, after a few years of significant growth, now seems capable of making an important contribution to US energy security.

On the demand side, the main variable is the use of natural gas for power generation.

The US gets about 50 per cent of its electricity from coal-fired plants, and a further 20 per cent from nuclear.

Many plants of both types are approaching the end of their working lives, and will need to be replaced.

The proposed EPA regulations curbing poisonous emissions from power stations will accelerate the end for some old coal plants, if owners decide it is not worth investing in the improvements needed to meet the standards.

Meanwhile, after the events in Japan, electricity companies will be much less likely to be able to secure the financing and regulatory approval they need to build a nuclear plant, or even get approval for a life extension for an old one, even though regulators have already allowed extensions for 63 of 104 reactors.

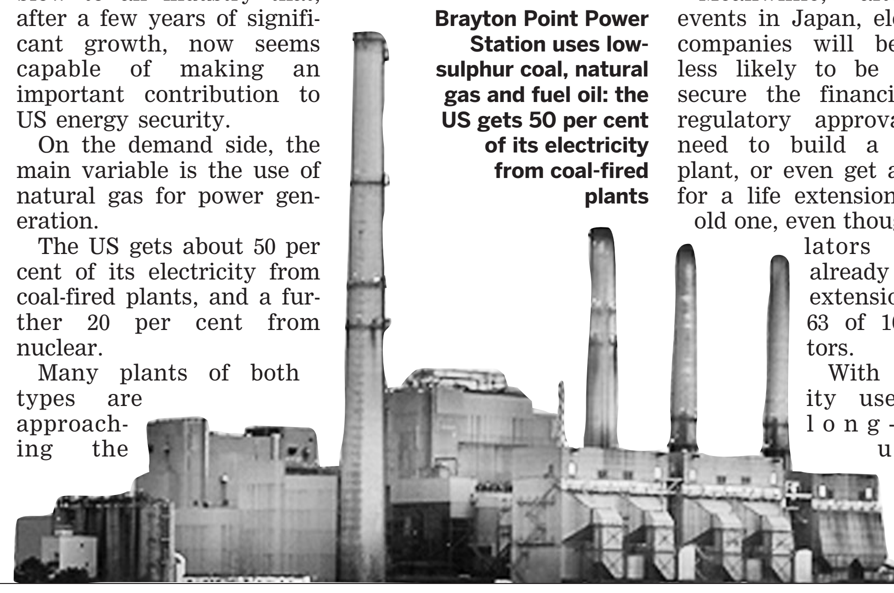
With electricity use on a long-term upward trend, thanks to the growing number of gadgets in homes, the plant closures will mean a shrinking margin of excess generation capacity, implying a greater risk of problems on the network, up to and including blackouts.

To avoid that, generators are likely to go for the quickest and easiest routes to building new capacity, which means building new gas-fired plants.

The fact that US natural gas prices are now very low adds to the appeal of gas-fired generation.

The problem is that US politicians are under pressure to do three things that cannot be reconciled: meet increased demand for gas, while not increasing either domestic production or – for reasons of energy security – imports.

For now, these contradictions can be partially set aside, but there may come a time, such as in the aftermath of the next catastrophe, when they can no longer be ignored.



Brayton Point Power Station uses low-sulphur coal, natural gas and fuel oil: the US gets 50 per cent of its electricity from coal-fired plants

Sweeter deal: higher energy prices have improved the economic competitiveness of fuels derived from plants, such as sugar cane AP

Plant power seen as only viable long-term alternative to petrol

Biofuels

Critics say the production process eats up land that could be used for food crops, says **Sylvia Pfeifer**

Henry Ford thought of it as the fuel of the future. When he launched his Model T car in 1908 he envisioned that ethanol, derived from the fermentation of crops, would power mass transportation – not fossil fuels pumped out of the ground.

Today, a century later, his vision has returned. Higher energy prices have improved the economic competitiveness of fuels derived from plants, and the world's big oil and gas companies are pumping increasing amounts of money into the sector.

BP this month paid $680m to acquire majority control of a Brazilian bioethanol and sugar producer, Companhia Nacional de Acucar e Alcool, the largest deal so far for its alternative energy business.

The UK company expects alternatives to be the fastest-growing energy sector over the next 20 years, with global biofuels production projected to more than triple.

BP is not alone in its bullish forecasts. Energy experts now accept biofuels are here to stay, but the outstanding question is how big a role they will play in the energy mix of the future. People have long agreed that there will be a need for liquid fuels for many years to come – especially in transport – and especially in a world where fossil fuel reserves are finite.

First-generation biofuels such as ethanol, derived from corn and sugar, are now well-established in many countries thanks in part to government incentives and policies.

Today there are about 100bn litres of production capacity globally, dominated by the US and Brazil, with Europe trailing in third place.

Mark Gainsborough, vice-president for strategy for portfolio and alternative energy at Royal Dutch Shell, says: "Governments around the world have introduced mandates for biofuels, and these policies have helped create a growing international market which we think could see biofuels increasing from 3 per cent of the fuel supply today to more than 9 per cent by 2030."

Shell last year teamed up with Cosan, Brazil's biggest sugar and ethanol producer, to create the country's second-largest fuel distributor.

It is undoubtedly a growing market, but the industry has been unable to shake off some questions that have dogged it from the start.

Critics say production of plant-based biofuels eats up land that could be used for food crops, and that they are too expensive compared with the equivalent fossil fuel. There are also questions about their environmental impact.

"We have been cautious over investment in 'first-generation' biofuel producers and related technologies," Ian Simm, chief executive of Impax Asset Management told the FT earlier this year.

He adds: "Although government support for this sector has been attractive, there are very low barriers to entry, so manufacturers struggle to sustain attractive profit margins."

In addition, analysts point out that the European market is unprofitable, thanks in part to low ethanol prices, at a time when wheat prices have been forced higher because of poor harvests. Wheat is a popular feedstock for ethanol production.

> 'The development of cellulosic biofuels, in other words non-food biofuels, is the Holy Grail'

"Europe's production capacity is about 20 per cent greater than consumption. In the US and Brazil the two are roughly matched," says Nick Wood, director in the energy practice at Deloitte.

Most of the oil companies, including BP and Shell, are working on second-generation biofuels as well as teaming up with partners in Brazil to produce conventional ethanol from sugar cane.

Shell, for example, is working with Iogen Energy, a Canadian company, to develop the processing technology to allow ethanol to be made from straw using enzymes.

"The development of cellulosic biofuels, in other words non-food biofuels, is the Holy Grail," says Henry Toller, biofuels analyst at Czarnikow, the sugar broker and consultant.

"On a more technical basis, the ability to move ethanol demand away from being a gasoline blendstock to an actual choice of fuel for the consumer at the pump, in effect replicating the Brazilian model, is critical," he adds.

Mr Gainsborough at Shell says: "Ultimately, all biofuels will have to compete with oil on a level playing field.

"We are investing in the production of Brazilian sugar cane ethanol that competes without subsidy and we are successfully progressing next-generation biofuels technologies from lab-based process to demonstration phase and towards commercial scale-up. But it will take time and investment to reduce costs and get these technologies to full-scale commercial refineries," he admits

Despite the obstacles, professionals in the energy business think biofuels are a good long-term bet. Philip New, president of BP Biofuels, says: "We see them as the only practical, feasible alternative to petrol."

BP has its sights set on Brazil but it is also investing closer to home. It has linked with Associated British Foods to build a £200m ($320m) bioethanol facility in Hull to make 420m litres a year from wheat feedstock.

When it is in full production, it will swallow 1m tonnes a year – equivalent to 5 per cent of British output.

UK suffers from legacy of North Sea abundance

Gas storage

Government intervention is vital to increase capacity to ensure supply security, reports **David Blair**

When North Sea gas production was at its height, British governments of all political stripes had no need to keep large reserves in storage to meet any contingency.

But the era when the UK could take security of gas supply for granted ended in 2003, when the country became a net importer of natural gas. From then on, Britain was exposed to many of the same risks faced by its neighbours.

Thanks to the legacy of safe reliance on the North Sea, however, Britain retains less gas storage capacity than other big European countries. Today, the UK can hold 5bn cubic metres of gas in reserve, enough to cover 14 days of normal consumption. The Rough storage facility, a depleted gas reservoir under the North Sea owned by Centrica, can hold 3.3bn cubic metres, making it the country's largest reserve by far.

Yet France could meet 91 days of normal consumption from gas supplies held in storage, while Germany could cover 77 days and Spain 65 days.

The British government has identified the expansion of gas storage as a strategic priority and aims to quadruple the current level of capacity over the next decade.

But the "big six" energy companies would have to come up with the money – and at present, new gas storage plants are not a good investment. The commercial rationale for building these facilities rests on the assumption that a company can buy gas at low prices and hold it in storage until prices rise and the stock can be sold for a profit.

In the past the seasonal difference between cheap summer gas and expensive winter supplies made storage a viable business in its own right. But the winter-summer differential in gas prices has narrowed sharply in recent years.

In the summer of 2006, gas sold for an average price of 44.9p per therm; by the time winter came in the first quarter of 2007, this had risen to 81.3p, according to figures compiled by the Energy Contract Company, a consultancy. This added up to an attractive price differential of 36.4p.

Since then, however, the summer-winter spread has fallen by about 75 per cent. On 1 March this year, gas prices per therm were only 9.5p higher than the summer average of 2010.

The availability of liquefied natural gas, imported largely from Qatar, has given the UK a new source of winter gas, helping reduce the seasonal price differential. Consequently, the commercial rationale for building more storage has been undermined at exactly the moment when a pressing need has been identified.

Some argue that imports of Qatari LNG reduce the need for storage capacity because they allow the UK to "re-gas" from overseas, while also diversifying sources of supply. The fact that the market has made gas storage unattractive reflects its judgment that holding supplies in reserve is less necessary.

But the verdict from the market may not reassure the government. "If you're the government and you're concerned about security of supply, then how secure do you feel with having re-gas capacity, rather than gas actually in the ground?" asked Trevor Sikorski, head of environmental market research at Barclays Capital.

"You could argue that LNG imports from Qatar involve some security of supply risk. From a policy perspective, does the government leave storage up to the market and the market will find a level of security of supply that it's comfortable with? Or does the government choose to intervene in some way?"

If the government is determined to increase the UK's ability to store natural gas, few doubt that intervention will be needed. At present, six projects to build new storage facilities with a combined capacity of almost 3bn cubic metres have been granted official planning permission. But all remain on hold because the energy companies concerned are not convinced of their commercial viability.

"It's not clear that the market is going to deliver the stimulus needed to build more storage," said Niall Trimble, managing director of the Energy Contract Company. "By the time the market works out that we're short of winter gas, it will be too late. The government will have to do something about it, because the market won't deliver on its own."

One option would be for the government to impose an obligation on the six leading energy companies to build more storage capacity. Under present market conditions they are unlikely to go ahead on their own.

In the meantime, a comparative lack of storage space makes the UK's liberalised traded gas market more vulnerable to price volatility than others in Europe. "Whatever the question is, the answer is to build more gas storage," said Mr Trimble.

"More storage would make the market work better. Because we have a traded market, if there's a lack of storage and a lack of availability at peak times, then prices will surge."

So more storage would reduce price volatility and guard against future supply shocks.

For all the attractions, however, only government intervention is likely to make it happen.

Energy in reserve: the Rough storage facility can hold 3.3bn cu m of gas