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Prices up, demand down

Forecasts for global oil consumption are falling, but not as fast as might be expected with crude at over $130/barrel. What is clear is the different impact seen in markets directly exposed to crude oil prices and those protected by subsidy. While OECD demand is contracting, strong growth is still evident in the Middle East and Asia. Almost all growth in 2008 is now expected from the latter two regions.

For the major oil producing countries of the Middle East this would appear sustainable while higher crude revenues offset the cost of subsidies, even if a deficit in refined oil products hurts. In China, subsidies have created a heavily loss-making refining sector, but the government's real fear is a potentially uncontrollable surge in already high inflation, if subsidies are removed. The upshot is that the world seems stuck with growing oil demand whatever the price of crude.

The other side of the equation appears equally worrying. Despite a sustained period of high prices, the supply side is underperforming, although there are increasing signs that the market is well supplied in the short term. For the last three years, buoyant January forecasts for non-OPEC supply growth have ignominiously shrunk with each passing month, and this year appears no exception. A lack of access to prime resources might be blamed, but the diminishing forecasts are for assets to which access has already been secured.

The difficulties of keeping up with demand are in part rooted in peak oil theory – having to overcome rises in consumption alongside depletion, while the 'easy oil' is ever harder to find – but it is also taking time for the industry to build capacity, as evidenced by the cost of rigs and other services. However, as demand growth declines, surplus capacity will rise. If it weren't for the geological bias towards OPEC, this might look a lot like a typical boom-bust trajectory.

– ross_mccracken@platts.com

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Editor
Ross McCracken
Ross_McCracken@platts.com
+44 1590 679 989

Managing editor
Paul Whitehead

Associate editor
Henry Edwardes-Evans

Editorial Director, European Power
Vera Blei

Production editor
Dominic Pilgrim

Editorial Director, Global Power
Larry Foster

Vice President, Editorial
Dan Tanz

Platts President
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Manager, Advertising Sales
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Officers of the Corporation: Harold McGraw III, Chairman, President and Chief Executive Officer; Kenneth Vittor, Executive Vice President and General Counsel; Robert J. Bahash, Executive Vice President and Chief Financial Officer; John Weisenseel, Senior Vice President, Treasurer.

To reach Platts

E-mail: support@platts.com

North America
Tel: 800-PLATTS-8 (toll-free)
+1-212-904-3070 (direct)

Latin America
Tel: + 54-11-4804-1890

Europe & Middle East
Tel: +44-20-7176-6111

Asia Pacific
Tel: +65-6530-6430

Advertising
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Sudanese tinderbox threatens oil industry

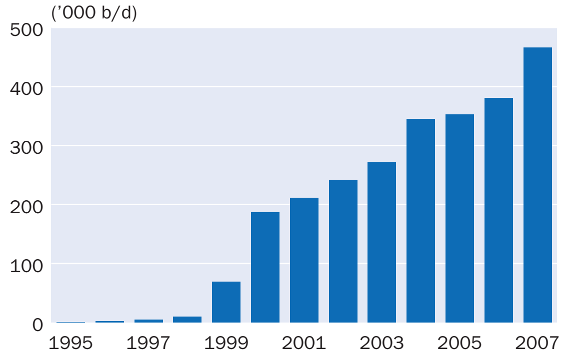
Much of Sudan's oil riches lie in the south and in three key north/south border states, but the export lines run north. As the 2011 referendum on secession approaches, there is little doubt that the south will vote to go, and war is likely if Khartoum resists. Having invested heavily in the country, both north and south, Chinese influence is likely to prove critical, while an all-out conflict could cripple Sudan's booming oil industry. **Neil Ford**

From a standing start, Sudan has taken just a decade to establish itself as the third largest oil producer in sub-Saharan Africa. Almost all investment has been provided by Chinese, Indian and Malaysian companies, with the result that the lion's share of Sudanese oil production now helps to satisfy rising energy consumption in Asia. Yet while the world's attention is fixed on the horrific conflict and humanitarian crisis in Darfur in the west of Sudan, the decades old dispute between north and south threatens to fracture the country along the lines of its most productive oil fields.

Armed conflict between the southern third of Sudan and the government in Khartoum raged from independence in 1956 until 2005, with only an uneasy truce between 1972 and 1983. It is often portrayed as a religious clash between the largely Arab, Muslim north and the Christian and animist south, but ethnic and regional divisions were just as important in encouraging secessionist feeling in what is Africa's biggest country. Even during and prior to British colonial rule, south Sudan had far stronger links with East Africa than with Khartoum, so the lack of national cohesion is not surprising.

The January 2005 Nairobi peace agreement, which brought the war to a close, granted the south autonomy until the end of 2011, when a referendum on secession will be held. In the meantime, southern representatives serve in the Khartoum administration under President Omar Hassan Ahmad al-Bashir and there is no requirement for Sharia law to be implemented in the south. The main southern rebel group, the Sudan People's Liberation Movement and its Sudan People's Liberation Army, dominate the new south Sudan government, although other factions are represented.

Sudanese crude oil production



Source: EIA

Border states

The situation is complicated by the geography of boundary delimitation. While ten of Sudan's 25 'wilayat' or states are recognized as being firmly in the south, leaving twelve in rump Sudan, the status of three states, Blue Nile State, Nuba Mountains/Southern Kordofan and Abyei has yet to be determined. Until the independence referendum is held, the three territories will essentially be governed by Khartoum, but their long-term fate could make or break the peace process.

Abyei is of particular importance because it contributes a large proportion of national oil production, while the Greater Nile Oil Pipeline passes through it, running from the highly productive Heglig and Unity fields to Port Sudan in the north. Under the peace agreement, Khartoum and the south Sudan government based in the town of Juba were to share oil revenues equally. Although the south has a smaller population, most oil production is either located in the south or close to the new border. The initial agreement has now been tweaked slightly, giving the south a 50% share, Khartoum 48% and the three borderland states the remaining 2%.

It would be wrong to give the impression of a cohesive, united south Sudan. Ethnic rivalries and jealousies have spilled over into violence between various armed southern groups since the 2005 agreement, but the level of bitterness over the decades of warfare and the two million lost lives means they are more than likely to unite around the SPLM if Khartoum threatens to renege on the Nairobi agreement. It is almost certain that the people of the south will vote for secession in the 2011 referendum. The question is whether Khartoum will accept it.

The fate of Blue Nile State, Nuba Mountains/Southern Kordofan and Abyei hangs in the balance. The government is currently undertaking a national census, but opposition groups fear the results will be manipulated to boost population figures in pro-government areas and reduce them in areas of strong rebel support. More than 160 census monitors were expelled from the south in April because of the controversy.

Oil development

It is against this unstable and fluid background that Sudan has emerged as an oil exporter of international importance. The country has long been mooted as a prospective destination for upstream investment, but even as recently as 1997, national oil production stood at just 4,800 b/d. Sudan's emergence as an oil power has been spectacular.

Sudanese output had grown to 180,000 b/d by 2000, owing to the development of the Heglig and Unity fields in the Muglad Basin on blocks 1, 2 and 4 by the Greater Nile Petroleum Operating Company. The owners of GNPOC have varied over the years, but equity is now held by the China National Petroleum Corporation (40%), Malaysia's Petronas (30%), India's Oil and Natural Gas Corporation (25%) and the Sudanese national oil company Sudapet (5%). Most European and North American companies pulled out of Sudan because of accusations that their operations were providing Khartoum with the financial means to step up its war effort against the south.

In April, Sudanese oil minister Zubair Ahmed al-Hassan said that oil output had breached 500,000 b/d and should reach 600,000 b/d by mid-2009 as CNPC brings new fields on stream, particularly in block 6 in the west of the country. The government now estimates proven oil reserves at 6.4 billion barrels, but the figure could be much higher given the lack of past exploration. Other areas of new production include blocks 13 and 15 in the Red Sea, where initial exploration by CNPC indicates that both oil and gas is present.

Most investment has been made by Asian firms, but South African state-owned oil and gas company PetroSA has carried out a seismic study in the giant block 14 in the far north, while Sweden's Lundin Petroleum has long standing interests in Sudan, including Block 10a, which includes an extension of the Muglad Basin, called the Anza Basin, where it has discovered oil. France's Total also holds several concessions, but has held back from a comprehensive exploration program because of political insecurity.

Despite uncertainty over Sudan's future, foreign firms are interested in securing new exploration acreage even in the south. In early April, the minister of industry and mining in the south Sudan government, John Luk, said he had received an application from privately-owned company H Oil for a concession next to Total's blocks B and C. His government has therefore created the new Ea block and has invited bids from H Oil and any other interested parties. In addition, Abu Dhabi's Mubadala Development Company is reported to be lining up a bid for block B.

Luk said: "We emphasized that security shall be maintained by the south Sudan police for the oil installations and the employees that are working there. We are sending the police now." Secessionist groups in other parts of Africa, notably Western Sahara, have often offered licenses for disputed territory in the past as a means of promoting sovereignty over their territorial claims. However, any such investment is likely to be limited until independence is guaranteed and the delimitation process completed.

Chinese influence

China could be crucial in determining Sudan's future because of its political and economic influence in Khartoum. CNPC is both the biggest foreign investor and biggest oil producer in the country, while Sudan is China's fourth biggest source of oil, supplying more than 200,000 b/d. In addition, China has vetoed attempts by the UN to impose sanctions on Sudan for Khartoum's role in exacerbating the Darfur conflict by backing military operations by the Janjaweed militia against both civilians and armed rebel groups in Darfur. Finally, Chinese companies are a major source – possibly the biggest source – of military hardware for the Sudanese army.

China's perceived role in backing Sudanese policy in Darfur has encouraged attacks on Chinese oil interests by Khartoum's opponents. In October, one of the main Darfur rebel groups, the Justice and Equality Movement, attacked the Defra oil field on block 4, where GNPOC is operating, and seized five Schlumberger workers as hostages for a month. The same group returned to a neighboring area in December where a GNPOC contractor, the Great Wall Drilling Corporation, was forced to halt operations. According to JEM, the government troops defending the oil field were forced to withdraw and the rebel soldiers were able to seize control of the area for a short period.

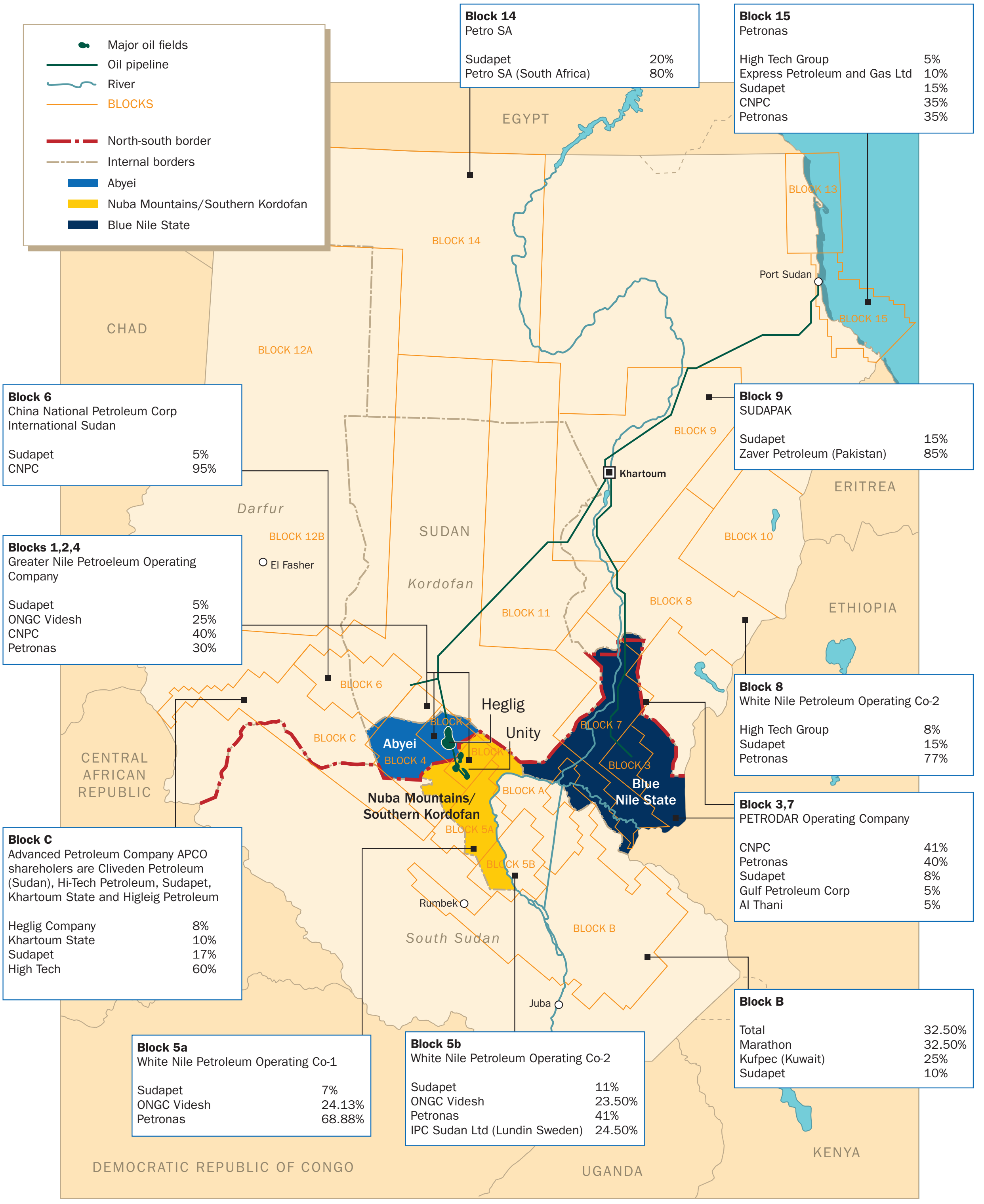
The chairman of JEM, Khalil Ibrahim, warned: "Every company should go from the area before we stop. We are calling on the international community to help us to stop oil production by the Chinese. China is taking oil for blood. We are just stopping oil production for blood." Just as other oil companies were accused of funding the war against the south, so China and CNPC are being accused of helping to finance government backed military operations in Darfur. By attacking GNPOC operations, JEM appears to be trying to emphasize the connection between the two.

In April, a spokesperson for JEM said his group wanted western oil companies to replace Chinese firms in Sudan because they would offer better guarantees on the distribution of oil revenues. He added: "We don't want China. We want to expel them. We have the means and we are preparing new attacks." Despite some protection from the Sudanese army, oil fields across central-southern Sudan seem increasingly vulnerable to attack, while defending the 1,590 kilometer Greater Nile Oil Pipeline could prove even more challenging.

Apart from becoming a target for opposition attacks, the Chinese could play a positive role in the north-south peace process by putting pressure on Khartoum to ensure that secession passes off smoothly. Beijing has been criticized for its policy of non-interference in the domestic politics of Sudan and other countries, although this stance is welcomed by some African governments tired of isolation and with few other friends in the international community. Yet the situation in south Sudan is very different to that in Darfur, where China has few interests at stake.

China has a great deal to gain by encouraging a peaceful, negotiated settlement of the north-south dispute and by seeking strong ties with south Sudan, owing to the economic and strategic importance of

Sudanese oil and the north-south divide



Source: European coalition on Oil In Sudan, EIA, Platts

Chinese oil interests there. Whether Beijing will seek to intervene or to build ties with Juba at the expense of its relationship with Khartoum remains to be seen. It depends on whether the Chinese government believes that southern secession is a real possibility, as Chinese diplomats will surely seek to court those it expects to win control of the oil.

Given the balance of probable outcomes, it appears to be in Beijing's best interests to use its influence to secure a peaceful outcome to the dispute. There are only two likely outcomes: either Khartoum will accept the south's vote for independence, transferring sovereignty over large Sudanese oil reserves to a newly independent state based in Juba; or Khartoum will not accept secession, leading to the resumption of full-scale armed conflict. There is virtually no likelihood of the south accepting the status quo.

The first option would allow oil development to continue in both the north and the south, enabling China to continue sourcing much of its oil requirements from both countries. It would also encourage Beijing to seek strong ties with Juba to ensure both oil supplies and the continuation of concessions held in the south by Chinese firms. Some level of cooperation will be required between Khartoum and Juba post-separation, given that most oil production comes from the south, or the three borderland states, while all export facilities in are the north, in Port Sudan.

The second alternative would destabilize the entire region, discourage oil sector development, probably result in attacks on oil sector installations and ultimately result in less oil being shipped to China. It is difficult to predict whether Khartoum will listen to Chinese pleas, but as the Sudanese government's most important ally, Beijing will certainly have more influence than anyone else.

All out war

There is a third possible outcome to the north-south dispute that could throw the entire future of the Sudanese oil industry up in the air, although it is less likely. While Sudanese government forces have been able to launch campaigns against south Sudan over several decades, and against the Darfur rebels more recently, they have never been able to muster the military strength to permanently overcome the opposition forces. Given the unpopularity of President al-Bashir in the rebel held areas and Sudan's pariah status among much of the international community, Khartoum's great fear has been the formation of a grand alliance of rebel forces seeking to overthrow the national government.

Aside from the SPLA, JEM and the other military groups in south Sudan and Darfur, there are other insurgencies against Khartoum in the Nuba Mountains and from the Eastern Front in eastern Sudan. A coordinated attack would certainly pose a challenge to the national army. Moreover, until recently, the Darfur conflict had been fought solely in Darfur, hundreds of kilometers from Khartoum, yet JEM and other Darfur groups have demonstrated an increasing boldness in their attacks and are now operating well outside their original zone of operation in the non-oil producing west.

On May 10, the Sudanese government was embarrassed by an attack on Khartoum's twin city, Omdurman, which lies on the opposite bank of the Nile to the capital. An estimated 3,000 JEM troops in 300 vehicles drove 650 kilometers to the city and engaged government forces across a wide area. Their attack was only stopped on the edge of central Khartoum. Jan Pronk, the former UN envoy to Sudan, commented: "The government of Khartoum may be under more pressure now to take negotiations seriously ... but that will depend on the pressure on the government from the international community."

Yet the south Sudanese army poses an even greater threat than the Darfur rebels. While the government of south Sudan currently has a vested interest in protecting oil sector infrastructure on its territory, any sign of Khartoum moving to block secession could trigger attacks on oil fields and pipelines just over the border. There are indications that it would not take much to re-ignite the north-south conflict, particularly in the tinderbox that is the oil-rich frontier state of Abyei.

On May 13 and 14, south Sudan forces clashed with the national army in the town of Abyei, killing three soldiers and forcing hundreds to withdraw. It seems that the lack of certainty over the state's fate is helping to stoke up tensions. These are easily exploited because under the Nairobi agreement mixed forces of northern and southern troops are required to defend the Abyei oil fields.

A full-scale war could end any number of ways, but even in the best case scenario it would be unlikely to have a positive impact on oil industry operations for a long time to come. If the worst happens, Sudan's position as one of the world's most important emerging oil exporters would come under threat.

Hanging in the balance

The north-south Sudanese peace deal seems to hang in the balance. Khartoum would lose much of its oil wealth if it allowed the south to walk away in 2011. While the situation in Darfur is not directly connected with the north-south conflict, the ongoing fighting serves to destabilize the entire country. There is a real possibility that full scale conflict could break out between Juba and Khartoum, most likely over the sovereignty of the three borderland states in central southern Sudan. Moreover, any post-independence oil sharing agreement is unlikely to survive the continuing enmity between north and south once south Sudan becomes a sovereign state.

The implications for the oil industry are difficult to predict. Asian oil companies managed to expand national oil production even before the Nairobi agreement was signed, and have continued successfully after the Darfur conflict erupted. They have proved more immune than their western counterparts to accusations that their investments help fund the violence. They might therefore be prepared to sustain their Sudanese involvement even if more general north-south fighting were to resume.

Yet a stable country is a more attractive investment option, particularly when large amounts of money have been committed to pipelines, refineries and other infrastructure that will only prove profitable after years of successful use. In addition to the country's existing productive oil fields, Sudan has many other prospective areas that could yet yield billions of barrels of oil. Development here will be unlikely without a lasting territorial settlement and long-term security. Few oil companies invest in fields with doubtful sovereignty, knowing they could be transferred from one jurisdiction to another at the stroke of a diplomatic pen, or, quite possibly, by force of arms.

US power prices: up, up and away

US utilities and their customers are feeling the pinch. Amidst the credit crunch, huge investments are needed to meet power demand growth, but inflation is rife across the supply side. Renewable obligations are pushing towards high-cost generation and the price of carbon has still to be counted. Gas remains the easy option, but that too has implications for a fuel which increasingly sets the marginal price of power. **Elisa Wood**

When asked where US energy prices are going, R. Skip Horvath, president and CEO of the Natural Gas Supply Association, offers two directions: "up" or "up and up." Horvath's views reflect warnings coming from many top players who are trying to brace the American consumer for a continued upward cost spiral. Already reeling from gasoline price hikes, the US now faces a likely new round of increases in electricity rates, as a combination of forces pressure utilities. Demand for power is growing. Costs for fuel and new infrastructure are up. And Congress appears ready to impose costly greenhouse gas emissions restrictions.

Few are more aware of these factors than the residents of New York, where electricity rates are the second highest on the continental US at 17.05 US cents/kWh. In May, just a few weeks after imposing a $425 million rate increase, US utility Consolidated Edison, which serves the majority of the New York area, again knocked on the door of state regulators saying it needs an additional $557-$654 million. The request came after two major credit rating agencies lowered the company's bond rating, and a third major rating agency put the company on negative watch. The utility says its revenue is not sufficient for adequate return.

Big bills for the Big Apple

Con Edison, which has $13 billion in annual revenue and $29 billion in assets, points to cost pressures beyond its control, such as a 23% escalation in copper prices and 71% in steel this year alone. The rise in copper prices led directly to a higher property tax bill for the utility, a major reason it sought the second rate hike. Tax appraisers increased the value of the copper in Con Edison wires in calculating the utility's tax.

The utility, one of the nation's largest, listed a series of other growing expenses in its plea to regulators. A small underground network of transformers now costs $34,200, compared with $26,600 18 months ago. A typical overhead transformer has gone up from $1,600 to $2,200 since April 2007. And the cost of high-voltage transmission cable increased from $66 per foot in 2006 to an average of $95 per foot in 2007.

These price hikes hit Con Edison particularly hard because the utility is embarking on major upgrades and an expansion of its distribution and transmission system. The improvements are necessary, in part, because customer are using much more electricity. The $5.5 billion in new infrastructure will help the company meet the 1.2% annual growth created by its 3 million customers in greater New York City.

The utility says consumers are using far more power-hungry devices. Con Edison's customers plugged in 650,000 new home computers between 2002 and 2007, and they are expected to add another 500,000 by 2012. They purchased one million air conditioners in the past five years and are likely to add 900,000 additional units over the next five, according to the utility.

New York is just a microcosm of the kind of demand growth occurring nationwide. The Edison Electric Institute expects US consumption to grow by as much as 30% by 2030. The average household uses 21% more electricity than it did in 1978, according to the EEI. Household consumption is likely grow another 11% over the next two decades.

Sticker shock delays projects

To meet this demand, the US needs to spend $900 billion on new infrastructure, according to the US government's Energy Information Administration. As utilities begin to accumulate bids for new projects, they face "sticker shock," according to The Edison Foundation report *Rising Utility Construction Costs: Sources and Impacts.* "While the full rate impact associated with construction cost increases will not be seen by customers until infrastructure projects are completed, the issue of rising construction costs currently affects industry investment plans and presents new challenges to regulators," the report says.

Sticker shock, combined with a growing not-in-my-backyard sentiment in certain areas of the country, is delaying new projects. As a result, construction of power plants and transmission lines has not kept up with demand. The North American Electric Reliability Corporation projects that US electricity usage will grow more than twice as fast as committed resources over the next decade.

NERC expects peak demand to increase by almost 18% (135,000 MW) in the next 10 years, and committed resources by only 8.5% (77,000 MW). Counting uncommitted resources, total resources would increase by 123,000 MW or 12.7%. As a result California, the Rocky Mountain states, New England, Texas, the Southwest and the Midwest could fall below their target capacity margins within two or three years.

"Frankly, we are at the point where we must consider how to meet our obligations and maintain reliability without all the infrastructure we need – we simply don't have enough time to solve many of our 'issues,' rather we must learn how to manage them," says Rick Sergel, NERC president and CEO.

The elephant in the room: carbon

As if this weren't enough, the industry is also bracing for what by most accounts will be substantial new costs as greenhouse restrictions come into play. No issue dominates price discussions more, as Congress gears up to debate a national standard. Meanwhile, ten eastern states already have cap and trade rules in place. Known as the Regional Greenhouse Gas Initiative, the program begins next year.

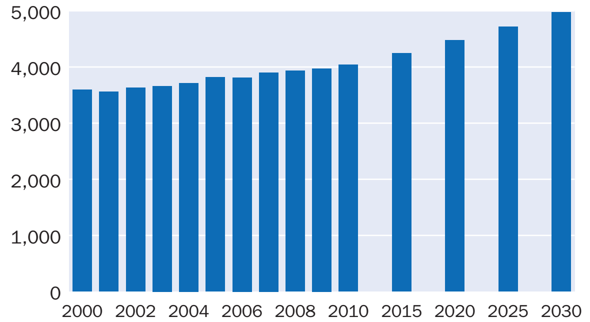
RGGI will come into effect in some of the nation's pricier electricity markets, among them Connecticut, Massachusetts and New York. As a result, businesses are growing increasingly edgy about what the initiative will do to their already burdensome energy costs. In New Hampshire, the state Business & Industry Association this spring launched a legislative campaign to place a ceiling on RGGI allowance costs.

Without it, RGGI could add up to $120 million per year to electricity rates. High energy prices in New Hampshire are already squeezing manufacturers, hospitals, ski resorts, offices, hotels and other large energy consumers, according to the business group. So the BIA is pushing for a $2/allowance price cap. If allowances trade above that figure, the money would be sent back to ratepayers in the form of a rebate. Any revenue the state earns below the cap will be put into a fund for energy efficiency programs.

The organization is also trying to convince state lawmakers to create an out-clause for the state, in case speculative bidding in allowance auctions begins to drive prices up too far. This concern has been echoed in other RGGI states. "The RGGI auction is open to anyone. This opens the door for speculators to purchase a significant amount of allowances to take them off the market and sell them later as prices spike due to a shortage of allowances," said Jim Roche, organization president. "Allowances sold in this secondary market provide no benefit to the state and no rebate to ratepayers."

Similar concerns are echoed on the national level, as many in the power industry are warily eyeing the leading greenhouse gas reduction bill that Congress is expected to start debating in June. The Lieberman-Warner Climate Security Act of 2007 would regulate greenhouse gases emissions through market-based mechanisms, energy efficiency programs, and economic incentives. The emissions cap begins in 2012 through an emission allowance program, and covers carbon dioxide, methane, nitrous oxide, perfluorocarbons, sulfur hexafluoride, and hydrofluorocarbons emitted from the production of hydrochlorofluorocarbons.

US electricity demand to 2030 (TWh)



Source: EIA

The consensus is that the Lieberman-Warner bill is likely to increase consumer energy costs. The question is by how much. The EIA attempted to answer that question in a report in April. With several wild cards in play, the federal agency made broad predictions. Excluding transportation, costs will grow somewhere between $30 and $325 per year per household by 2020 and $76 to $723 by 2030, the report says.

A key cost driver is coal for power generation, which rises between 161% and 413% in 2020 and between 305% and 804% in 2030, under the EIA forecast. Overall, the price of electricity grows 5%-27% higher in 2020 and between 11%- 64% in 2030, owing to the climate change legislation.

Because the carbon restrictions increase energy costs, the bill could dampen economic output, reduce purchasing power, and lower demand for goods and services. "The result is that projected real GDP generally falls," the report says. The EIA forecasts GDP losses from $444 billion (-0.2%) to $1,308 billion (-0.6%) over the 2009 to 2030 time period. Industrial activity, including manufacturing, is hardest hit, with shipments dropping from between 2.9% to 7.4%.

The bill is likely to lead to broad retirement of coal-fired generators – the dominant fuel for power generation in the US. This will significantly increase the total amount of new electricity capacity that must be added between now and 2030, the federal agency warned. The problem is, what will replace it? Low carbon resources like wind power and nuclear generation face public opposition and in some cases technical or financial obstructions.

Another inconvenient truth

A major fear is that the US power industry will take the easy road and continue its so-called "dash for gas," the frenzy of construction in gas-fired plants that has occurred over the last decade. The temptation exists because gas-fired generators have lower carbon emissions than coal-fired power plants and are relatively inexpensive and quick to build. They face far less regulatory scrutiny or public opposition than nuclear plants. The downside is that gas has proven, in recent years, to be a pricey fuel. And the power sector's new demand for natural gas is driving costs up further.

The EIA sees nuclear power stepping in to serve future demand growth, with the development of 16.4 GW of new capacity. But many industry analysts are skeptical about whether a nation that has resisted new nuclear development will pick up the pace quick enough for nuclear power to offset the pricier gas option. And the EIA concedes carbon-reduction costs are likely to be much higher if nuclear plants are not developed.

"Natural gas-fired power generation is expensive kilowatts. But for power generators, it doesn't matter because natural gas costs are automatically passed through to the ratepayers," said Paul Cicio, president of the Industrial Energy Consumers of America. "Natural gas powered generation is being used to set the marginal price of electricity in a growing part of the country. As natural gas prices go up, so does the price of electricity."

He added: "Almost all natural gas-fired generation is used as peaking. In a carbon constrained world they will be running that capacity more. There is nothing in the Lieberman-Warner bill that would stop utilities from using more natural gas in existing capacity and fuel switching from coal to natural gas. That should be of great concern to every member of Congress."

Indeed, Horvath of the Natural Gas Supply Association says that growing demand for natural gas by generators is already driving up the cost of natural gas for home heating and other non-electric uses. Natural gas prices rose from $7.60/MMBtu in April 2007 to $10/MMBtu in April this year. Five years ago natural gas sold for $5.26/MMBtu.

The Natural Gas Council had analyzed an earlier climate bill, S. 280, and found that it would create a 20% increase in demand for natural gas. The newer Lieberman-Warner bill has even tougher environmental restrictions, Horvath said, so will put even greater pressure on gas supply. At the same time, the bill "does nothing to increase our domestic supply of natural gas, but it should," he says. The issue, he said, is not that the US will run out of natural gas, but "what will the price be."

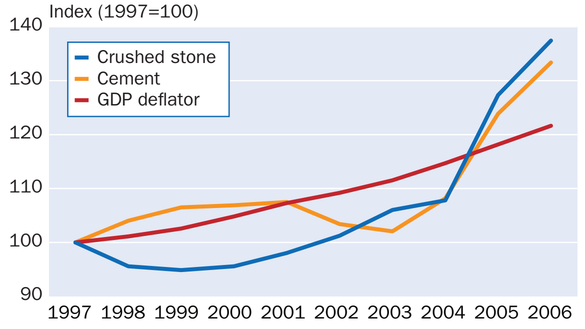
More recently, the American Petroleum Institute issued a report that found US natural gas production could drop 6% under Lieberman-Warner because of increased costs to develop new wells. "Congress should be looking for ways to increase natural gas production, and we're willing to work with elected officials to do just that," Horvath says. "Less natural gas and increasing demand will mean upward pressure on prices in coming years. That's an inconvenient truth, but it's something we can fix by making more natural gas available."

Clean, green but costly

The US has been developing wind power at a rapid clip, with wind generation making up 35% of the new capacity installed in the US last year. The resource is promising because it not only helps reduce greenhouse gases, but is also seen as a long-term price hedge against the volatility of natural gas. The "fuel" costs of wind power remain unchanged.

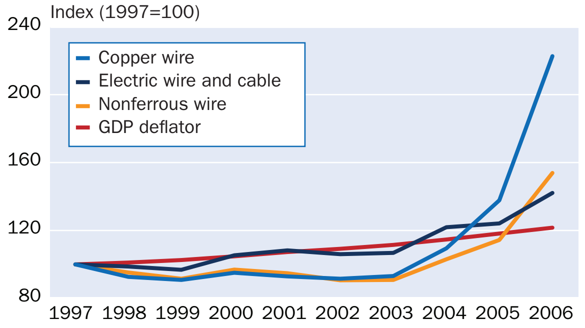
However, a major rating agency recently issued a report saying that a key government incentive that helps drive wind growth – the renewable portfolio standard – could

Cement and crushed stone price indices



Source: US Geological Survey, Mineral Commodity Summaries and the US Bureau of Economic Analysis.

Electric wire and cable price indices



Source: The US Bureau of Labor Statistics and the US Bureau of Economic Analysis

prove costly to utilities over the long run. About half of US states now have RPS rules, which vary by state, but generally require that a percentage of utility power comes from renewables. The percentage ramps up annually until the state achieves its final goal.

Some states have set aggressive targets. Minnesota requires that Xcel Energy achieve a 30% RPS by 2020. New York wants 24% of its power to come from renewables in just five years; Connecticut seeks 23% by 2020 and New Jersey 22.5% by 2021. A half dozen other states are pushing for one-fifth of their power supply to be green in the next 12 years.

Standard & Poor's Ratings Services says these standards could cause utilities financial harm in its report *The Race For The Green: How Renewable Portfolio Standards Could Affect U.S. Utility Credit Quality.* The rules are moving utilities "squarely away from least-cost procurement and toward acquiring often above-market renewable generation in unprecedented quantities," said the report.

"We are concerned that the costs of RPS compliance have often not been quantified and that absorbing the full costs of RPS in retail rates could have credit implications for some companies," says Anne Selting. Standard & Poor's credit analyst. S&P likens the RPS to the infancy of deregulation in 1990s, when it was universally hailed as a good idea. Similarly the RPS is "typically discussed in unimpeachable terms," suggesting that a sizable shift toward renewable generation can occur "quickly, will carry little rate impact, and entail minimal disruption to the sector."

In reality, consumers will begin paying for RPS at about the same time their pocketbooks are hit by GHG reductions and "unprecedented" new capital spending. "Collectively, we expect these expenses to substantially increase retail electric rates in coming years, which will pressure the regulatory compact and stress customer satisfaction. This risk is largest in states that have aggressive RPS. Coincidentally, high RPS states tend to be those that also have some of the highest retail electric rates in the nation," S&P says.

Questioning the consensus

By contrast, most studies to date indicate that the RPS will have little impact on consumer costs. But S&P questions the studies, saying they tend to be written by renewable energy advocates. "From a credit perspective, it is troubling that there is very little public data that assess the actual costs incurred to date to implement RPS. Compliance reports that state commissions or legislatures require to document RPS progress are nearly universally silent on what costs utilities have incurred to meet RPS," S&P says.

"This is of particular concern in California, where RPS contract data is considered commercially sensitive. There has been no public disclosure of information necessary to calculate the above-market costs of RPS. Due to delays in getting projects on line, these costs will likely occur in a swell in 2010 and 2011. It is unclear if policymakers have a sense of overall rate impacts on customer bills."

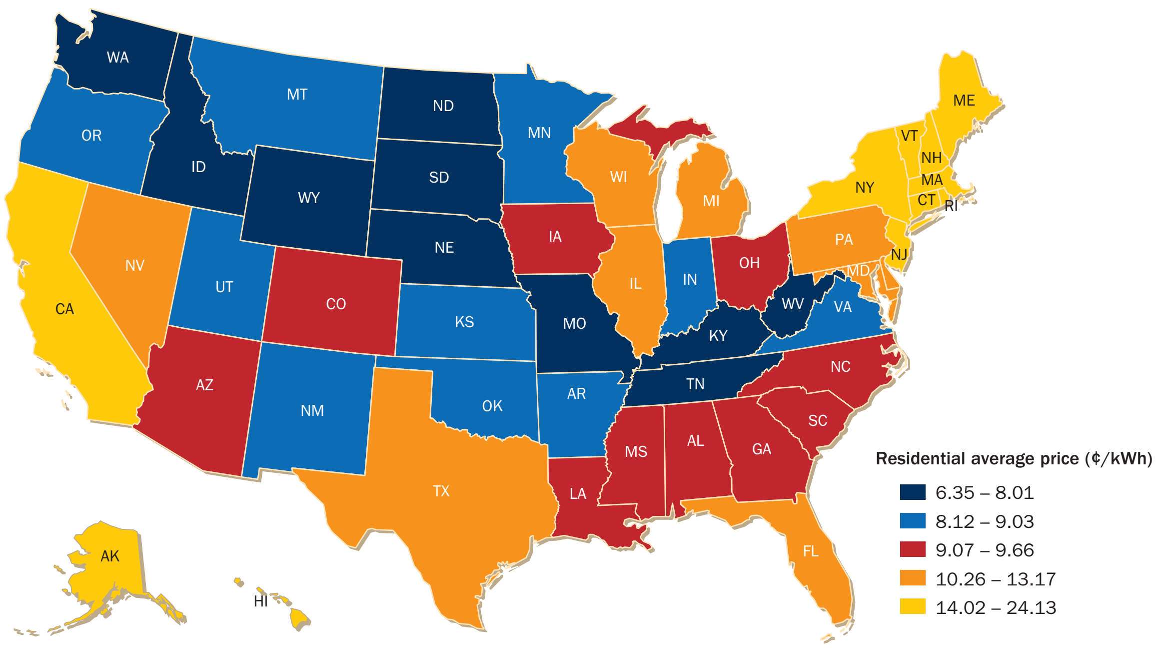
As a result, many states are beginning to put money into energy efficiency as the quickest and most cost-effective pursuit – at least over the short-term. Efficiency and demand response can defer construction of costly new infrastructure and keep down greenhouse gas costs. Many states have announced targets – much like the RPS – to reduce energy usage by a specific date.

New York regulators are exploring ways of reducing demand by 15% by 2015. But they are proceeding cautiously, concerned that the medicine for rising costs – efficiency – could also increase rates, at least over the short-term. Indeed, in its recent plea for $557-$654 million, Con Edison said it needs the money, in part, for the conservation and load management incentives it plans to put in place to help the state achieve its 15% goal.

In short, the one safe bet in the US power sector is that power prices are going up over the next few years. It is difficult to quantify exactly how much given the many variables in play – the specifics of greenhouse gas rules, the resources that will ultimately be built and whether renewables and efficiency will deliver on their promises. The US consumer is already grumbling about high gas prices and a slowing economy. Look toward what S&P calls "rate hike fatigue" as the next big policy discussion.

Patrick Costello, a research assistant, contributed to this article.

US residential retail prices for electricity in 2007 (US cents per kWh)



Source: EIA Annual Energy Outlook 2008

Getting gas to Guangdong

With more LNG terminals planned and pipelines under construction, greater volumes of gas will soon start flowing into China's industrious coastal provinces. Guangdong alone represents a market of 100 million people and government policy is actively supporting the expansion of city gas. As a result, gas is increasingly showing up as a profitable growth area for China's oil and gas companies. **Jonty Rushforth** reports.

In 2007, the GDP of the southern Chinese province of Guangdong rose to 3.06 trillion yuan ($422 billion), with a per capita figure of more than $4,000, overtaking Taiwan. Two years earlier the province had become the most populous in China, when the number of people living there reached over 100 million.

By contrast, demand for natural gas in the province is in its infancy and only began in earnest following the construction of the 3.7 million ton/year Dapeng LNG terminal in 2006. With that terminal up and running, an expansion proposed, and a new onshore pipeline expected to reach the area in 2011, the gas market in Guangdong looks set for rapid and sustained growth.

Competing with coal

Imports through the Dapeng terminal have been split between local power generators and city gas companies, with about 45% going to the latter. Contracted generators have between them 12 350 MW turbines, which means, if they operated flat out, they could consume 4 million mt of LNG in a year, more than Dapeng could provide.

However, much of China's electricity comes from much cheaper coal-fired plants, and the state-controlled price for electricity reflects that. Gas-fired generation is often not profitable. Dapeng LNG has a contract with Australia's Woodside Petroleum for 3.3 million mt/yr of LNG, reportedly at a price of under $4/MMBtu. Extra capacity at the terminal must generally be filled through spot purchases, which has meant prices of above $12/MMBtu this year. This has squeezed profits for generators, and many are thought to have switched to heavy oil, despite a government pronouncement that they would be able to pass on higher gas costs to electricity customers.

China's national government is trying to reduce coal-fired generation because of its high level of emissions. Ben Hua, director of the Research Center of Natural Gas at the South China University of Technology notes: "The environmental pressure is very serious. The problem is how to substitute coal with gas. At the moment, there's a lot of focus on research." He says he has been campaigning for the use of combined heat and power plants, which can raise peak plant efficiencies above 90%, and would counteract coal's price advantage.

"You cannot construct so many CCGTs with such a high gas price – it just can't compete with coal. The only way to change that is to move to CHP, using gas, which would be particularly useful in the north," he says. The growth potential for this in China is particularly high, Hua notes, because apartment blocks, where you could use district heating, are very common. If the government were to come out convincingly in favor of CHP, that could indeed see the country shift away from coal. But for now, gas demand growth is unlikely to come from generators, he argues.

City gas

But if gas-fired generation faces constraints, city gas is providing an economic alternative. Demand for city gas continues to grow steadily, owing to local regulations and the burgeoning middle class. Telly Wong, vice president of the development department at Shenzhen Gas Corporation, which operates a city gas network in the Shenzhen free trade zone in Guangdong, says his company currently has total demand of 250,000 mt/yr, all sourced from the Dapeng terminal. And the company expects that volume to double within five years.

"Most of our demand growth is coming from commercial customers, because natural gas is so much cheaper," he says. Most people still use LPG in Shenzhen City, he explains, but natural gas is cheaper, so everyone who can switch generally does. "The only limit on people switching is the growth of the pipeline network, which is why we are investing so much in that." The company aims to spend 300 million yuan per year for the next few years on the pipeline network, expanding its reach across as many households as possible – which in the Shenzhen area means 3 million.

The company's gas demand is currently split 50/50 between its residential customers, and commercial and industrial customers, made up of 850,000 households and 3,000 companies, Wong says. Local regulations are encouraging growth, he adds, because all new high rises must use natural gas, and new commercial boilers in the Shenzhen urban area are not allowed to use cheaper heavy oils, because of pollution concerns.

Aside from heavy oils, the other competing fuels are LPG and diesel, but both of these are more expensive than natural gas, Wong explains, leaving methane as the fuel of choice for a growing number of people. Residential customers pay a fixed amount of 3.5 yuan/cubic meter, commercial customers pay 3.95 yuan/cu m, and industrial customers pay a variable amount, which is currently more than 4 yuan/cu m, he says.

SGC's demand has already grown beyond the level of its contract with Woodside, and Wong says that in the past year the company has been party to spot purchases of LNG cargoes through the Dapeng terminal. "They were buying one or two a month I think, and we shared in many of those cargoes." However, that means higher prices for SGC, while the prices their customers pay were fixed when international prices were lower. "This year will be very difficult for us as a result," Wong said, adding that some of the shortfall can be made up from flexible contracts with industrial users.

Under the contract with Dapeng, which runs for 25 years, city gas takes priority over power generation in the event of a supply shortage, Wong explains. But many of the generators could switch to heavy oil, and with electricity prices flat, gas-fired generation is hardly attractive anyway.

The Dapeng contract volumes increase each year by about 15-25% to 2011, he says, and are fixed from then on. City gas companies in Guangdong will need to look elsewhere for increasing supplies from that point on. A second LNG terminal in Dapeng has been proposed as a joint venture between the Chinese National Offshore Oil Corp. and Shenzhen Energy, a power company, Wong says, but much of the output from that is expected to be earmarked for generators.

Instead, the city gas companies are looking to China's next major pipeline project, the second west-east pipeline. State-owned oil company PetroChina is building the 9,000 kilometer line from Xinjiang in the west across China, with branch lines to the Yangtze River delta in the east, which includes Shanghai, and down to the Pearl River delta in Guangdong. "The price of the pipeline gas is likely to be cheaper than the price paid to Dapeng," Wong says.

PetroChina aims to finish the first section of the pipeline in 2009, with the spur down to Guangdong completed by 2011. The main source of the gas for the pipe will be a 30 Bcm/yr contract with Turkmenistan, with further supplies coming from China's own domestic sources.

Li Huanqi, secretary to the board at PetroChina, says that while the share of gas to be sent to the different provinces has been fixed, the company is looking to be flexible, and will respond to market demand. Wong says the residential retail price of gas in the Yangtze delta is about 2.5 yuan/cu m, whereas in Guangdong it is 3.5 yuan/cu m. Li adds that the price charged for the gas to distributors will simply be the border price plus transportation.

Pipeline grid

To take advantage of Guangdong's growing demand, PetroChina said in April that it would join rival state-owned companies, Sinopec and CNOOC, to develop a gas pipeline grid in the province. Creating a more integrated grid is already under way across the whole country, and Li says that once the second west-east pipeline is complete, PetroChina will have a true "net" across China. The pipeline will be linked to the first west-east pipeline, which runs from Xinjiang to Shanghai, so gas could be moved across much of the country according to demand.

That means Guangdong should benefit from the wider development of China's natural gas industry, including its massive investment in LNG. While Dapeng is currently the only terminal in operation, a second terminal in Fujian, only a province away from Guangdong, is expected to be commissioned this summer. And a further eight terminals are planned, all but two of which have received government approval.

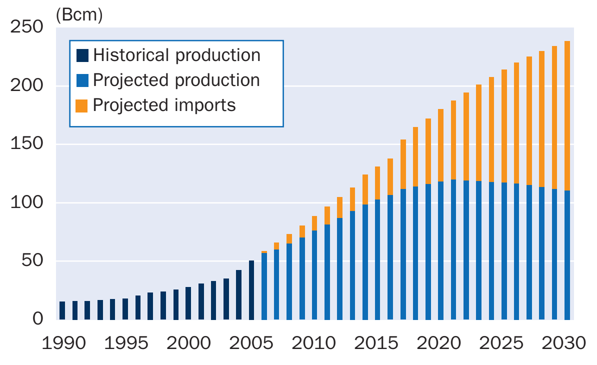
Hua, director of the Research Center of Natural Gas, says the Fujian terminal is likely to receive its first cargo in June, from Malaysia. He has been working on the feasibility study for the second Dapeng terminal, and believes the future is bright for China's LNG projects. "There will be no difficulty in getting the latest terminals approved [by the government] and we will see all ten terminals constructed."

But, he cautions, China should also ensure that it maintains its investment in domestic gas production. "Current proven domestic reserves are at 5 Tcm, but there's a possible level of 20-30 Tcm … The level of Chinese imports will really depend on how much we can develop our domestic gas supplies. We should be mainly reliant on this. I expect that in five to ten years, we will get 70-80% of our supplies from domestic production, with the remainder coming from pipeline or LNG."

There is also potential from coal bed methane, Hua notes, for which a new policy was recently announced. CBM was previously controlled exclusively by the China United Coal Company. "But they moved very slowly," he adds, and the industry has now been opened up to other investors, with companies coming in from the US and Canada. If CBM takes off, that could add to China's need for an integrated, nationwide transportation network, but at least some of the load will be carried by trucks, Hua says. There are 600 LNG trucks in China, and about 100 regasification stations. "It's a transparent, mature market. The stations are all over China, but mainly in the south east."

Hua says he expects that gas from at least one CBM project, in Guizhou, will be sent by truck to Guangdong. And the price for truck transportation is roughly equivalent to pipeline, he adds, at about 1 yuan/cu m, if the truck itself runs on gas rather than diesel. In a few years time

China's gas balance



Source: IEA WEO 2007 Reference Scenario

Main Chinese gas pipelines

Source: IEA WEO 2007, Green Dragon

Guangdong could find itself in the enviable position of seeing a flood of gas coming from both onshore and offshore. But as China's largest and most prosperous region, the demand will certainly be there to absorb it.

Gas profits

Growing demand for gas is also showing up as an increasingly important part of China's state-run oil and gas companies' profits. When PetroChina announced its first-quarter 2008 results, one notable bright spot was the 18% jump in natural gas production, compared with a 31.5% drop in overall net profits.

"It is becoming a more important profit contributor, and volumes are increasing year by year," said Li. He adds that operating profit from one segment, natural gas pipelines, is now the second largest contributor to the company's overall profits, and expects that share to continue to grow.

The importance of natural gas to the company is partly due to government policy. Natural gas currently accounts for 2.8% of China's primary energy consumption. But by 2012, the state wants to increase that share to 8-10%, Li says. "It's a clean product with a good heat rate, so China is going to continue its efforts to develop it. There's going to be 18% growth per annum of natural gas production."

Gas also compares favorably with oil. Government caps on oil product prices often result in negative refining margins. In May, PetroChina's chairman Jiang Jiemin said that the break-even point for PetroChina's refining segment was $66-$67/barrel of crude processed. For every $1/b increase from that level onwards, the company would incur a yearly loss of Yuan 3.24 billion ($417 million).

In contrast, gas goes straight from the well-head to the downstream consumer. And the price formula is simple, Li says. "The city gate price equals the wellhead price plus the transmission cost." That means guaranteed income for a company with over 20,000 km of pipelines.

In addition, an independent appraisal for 2007 put the company's reserve replacement ratio at 3.238, giving plenty of scope for expansion. Growth will come from the company's four major gas basins, south west China's Sichuan and Ordos basins, and the Tarim and Daqing basins in the north west.

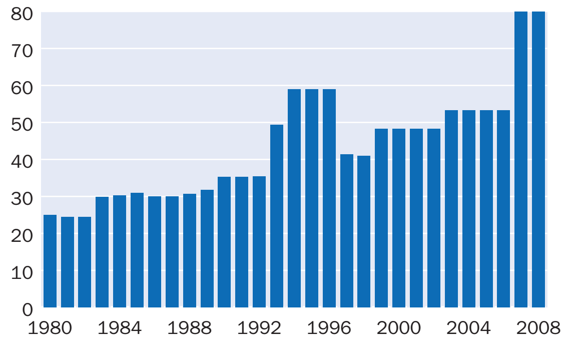
In addition to planned pipelines to Guangdong, China's other main economic zone is the Pearl River delta in the south, covering Guangdong province and Shenzhen city, a free trade zone. Access to that area will give PetroChina a host of new gas customers.

And Li says it could also lead to PetroChina servicing another of China's economic powerhouses, Hong Kong. "We have another plan for a trunk line to reach Shenzhen, which would have a capacity of 10 Bcm/yr. That's a huge quantity of gas for Shenzhen, so it's likely we would transport a portion of that to the Hong Kong market," he explains.

PetroChina will have still more options once its move into LNG comes to fruition. It currently has three terminals under construction, with those at Dalian in the north eastern Liaoning Province and Rudong in the eastern Jiangsu province under way, and the Caofeidian project at Tangshan in northern Hebei province in its initial stages, Li notes. That will give the company a total regasification capacity of 12.5 million metric tons of LNG per year, around 17.2 Bcm/yr of gas.

But PetroChina will mainly look to use LNG as a supplement to pipeline gas, Li says, rather than as the main source for imports. "The transportation of LNG requires expensive vessels and regasification facilities, which requires a huge amount of investment," he adds. "For our terminals, the earliest to come on-stream will be in 2012/13, so we still need to do lots of work."

Chinese proved natural gas reserves (Tcf)



Source: EIA

But PetroChina is still set to become a significant player in international LNG markets once it has its fleet of vessels and terminals up and running. The company has already signed several long-term supply deals with Qatar and Australia, and "as long as it economically viable, it is very likely that we would choose to do some short-term contracts as well," Li notes. "But the key emphasis should be on long-term contracts, which are stable." And, "with the depreciation of the dollar and the appreciation of the renminbi, the efficiency of imports will improve."

China quake to worsen power shortages

Guangdong was already braced for power shortages during its period of peak demand over the summer, but now faces lower internal imports, owing to the earthquake that rocked Sichuan in May. The earthquake has exacerbated coal shortages and increased dependence on increasingly expensive fuel oil imports. China's bill for oil product subsidies is set to rise, while a new ban on coal exports may be in the offing.

The devastating earthquake in China's Sichuan province in May, which is estimated to have killed more than 34,000 people and injured hundreds of thousands more, could have a substantial impact on China's domestic energy supplies, with knock-on effects for international commodity markets. Price effects have already been felt across a wide range of commodities, in terms of the initial disruption to production and supply chains, in the redirection of commodities as part of the emergency relief effort, and then, looking forward, to the costs of reconstruction in Sichuan.

Coal: Disruption to coal mining in Sichuan and to transport links have exacerbated an already low level of stocks at Chinese coal-fired power plants. A total of 199 coal mines – with a combined mining capacity of 14.50 million mt/year – have been affected by the earthquake, according to the National Development and Reform Commission. Of the 199 coal mines, 60 have their shafts flooded.

While this represents only a tiny proportion of China's coal output, stocks were already low. The State Electricity Regulatory Commission said on May 22 that nationwide 32 coal-fired power stations had ground to a halt due to a lack of coal. This has led analysts to argue that the government may impose a second ban on coal exports to allow stock levels to recover. The government imposed a ban in February, following a period of severe weather, which disrupted transportation and coal production.

Natural gas: Sichuan is one of China's main gas basins, supplying a localized network. PetroChina reported that it had resumed 99% of its gas production by May 19, after its subsidiary PetroChina Southwest Oilfield cut output by 197 MMcfd (5.6 MMcmd) immediately after the earthquake. Falling local demand meant a build-up of gas in transmission lines, causing a cut back in production. In 2006, PetroChina Southwest Oilfield produced 441 Bcf of gas, almost 32% of PetroChina's yearly total. As of May 16, Sinopec Southwest Company had 404 wells producing 107 MMcfd of natural gas, while 564 wells remained shut-in. In 2007, Sinopec Southwest Company produced 261 MMcfd of gas.

Oil products: China's Sinopec Corporation reported that it had redeployed gasoil, gasoline and jet fuel originally meant for markets in southern and central China to Sichuan to support the relief operation. The country's near-monopoly jet fuel distributor China National Aviation Fuel Holding also sent emergency jet fuel supply to Sichuan as damaged land links meant a greater reliance on air. The impact appears likely to be long lasting – Sinopec said May 28 that it will extend into the third quarter a temporary halt on exports of oil products as a result of the earthquake.

Between May 12 and May 18, CNPC diverted 63,500 mt of oil products, cutting back on supplies to Hunan province, Hubei province, and Maoming and Zhanjiang cities in Guangdong. PetroChina's only oil refinery in Sichuan, the Nanchong Oil Refinery, with a refining capacity of 1 million mt/year, was forced to stop production. CNPC reported damage to 47 oil storage terminals, 165 crude oil and natural gas stations, and 71 oil transmission pipelines.

Steel: Demand for steel and other metals and materials used by the construction industry is expected to rise over the next two to three years as a result of reconstruction in Sichuan, but no short-term spike in prices was expected. The average monthly steel output of Sichuan province and Chongqing municipality accounts for about 3% of the nation's total. In April, the combined steel output of Sichuan and Chongqing amounted to 1.44 million mt, compared with a national total of 51.6 million mt.

Power generation

The effects of the earthquake on industry may be felt most later in the summer and not in Sichuan itself, but further south. Sichuan is not a heavily industrialized region, but it does have hydro plant which feeds power into the southern coastal regions. The southern coastal provinces are home to much of China's modern export-based industries and still rely heavily on fuel oil, in particular for marginal power generation.

Even before the earthquake, the Guangdong authorities expected power shortages this summer. Power conservation measures had already been put in place, requiring local factories to shut down at designated times or reduce production. In addition, Guangdong has already suffered shortages this year. Severe snow in January and February resulted in a shortfall of about 1.2 GW, easing to around 300-500 MW in March as power flows from Sichuan and the giant Three Gorges hydro project resumed. Guangdong is heavily dependent on power imports from other provinces.

In February, Li Xiangming, Guangdong's deputy director of the economic and trade commission, was quoted in the Chinese media as saying that he expected the province's load gap to reach between 11 and 12 GWh during peak consumption periods this year, the largest ever shortfall. According to the commission, electricity demand was expected to rise to almost 50 GW in April, and potentially to 63 GW in summer, depending on temperature. The province has generating capacity of 38 GW.

Guangdong gets about 3 GW of power from the Three Gorges dam. Based on the commission's expected shortfall at peak summer demand and reports of how

Energy production and distribution of industry

North East

- Old industrial heartland.
- Iron, steel and heavy engineering
- Coal and oil-producing region
- Daqing oilfield and coal fields in Manchuria and Inner Mongolia
- Plentiful thermal generation

Central-Eastern

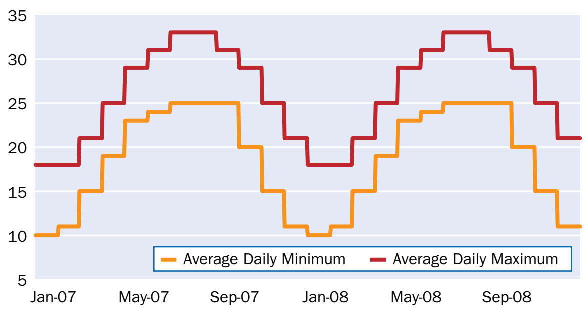
- Fast-growing new industrial heartland along the Chang-jiang and on the east coast
- Shanghai-Zhejiang are heart of domestic economy
- Export-oriented industries plus basic commodities (aluminium, copper, zinc, cement)
- Plentiful hydro-generation from Changjiang/Yangtze system
- Mixture of thermal and hydro power
- Seasonal problems when water levels drop in winter and air conditioning demand rises in summer

South

- Guangdong is home to the mostly (foreign-invested) export base
- Semiconductor factories and other higher-value exports
- No local thermal resources, some hydro
- Region still depends heavily on imported fuel oil

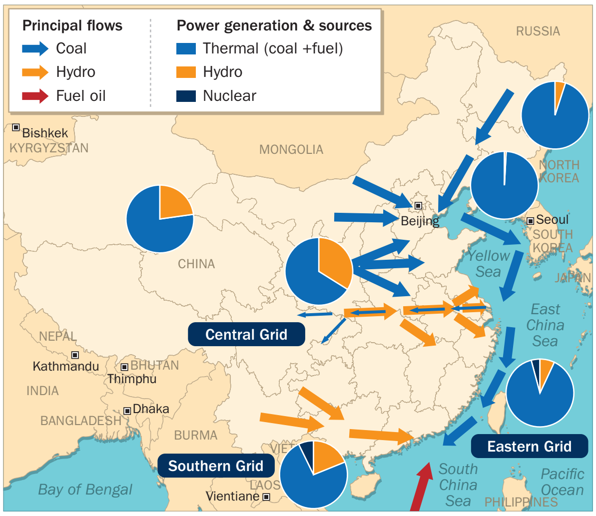
Source: RBS-Sempra

Guangzhou daily temperatures (°C)



Source: Xinhua

China energy flow, generation & sources



Source: RBS-Sempra

much import capacity was lost in the winter snow storms, total provincial import capacity appears to be around 10 GW, suggesting up to 7 GW from other provinces, including along west to east power lines. While power imports had resumed prior to the earthquake, damage from the snows in January-February to west-east power lines was not expected to be fully repaired until the second half of the year.

Guangdong's power demand is highly sensitive to temperature. It has been estimated that a 1 degree Celsius rise results in a 1 GW increase in power demand. The earthquake comes just as Guangdong enters its season of peak demand. If high temperatures are seen over the summer, power shortages will be widespread.

Damage in Sichuan

China produces about 18% of its electricity from hydro power, which is situated predominantly in the centre of the country around the Three Gorges and in the south in Yunnan and Sichuan provinces, and in the north east on the Yellow and Songhua rivers. Hydro power is highly seasonal. Flood waters start to reach the main reservoirs from May and June, when the plants are run at full power to meet peak power demand as summer temperatures rise. Reservoir levels only start to rise in October, peaking between November and January. They are at their lowest level in June-August.

The earthquake hit dams in Sichuan, and the province was reported to have lost 4.4 GW of its 30 GW capacity at the height of the crisis, although according to a release by the State Grid Corporation on May 13, power grids in Sichuan Province had lost one third of their electric load as at least eight power plants and eight transformer substations were damaged by the quake. Gu Junyaun, chief engineer of SERC, told reporters on May 19 that power supply in Sichuan had been restored to 80% of the pre-quake level.

According to the Chinese state media, 17 reservoirs in Sichuan and Chongqing were damaged, with dams showing cracks and leaks. Water Resources Minister Chen Lei said "Especially in Sichuan province, there are many dams, damage from the quake is extensive and the hazards are unclear." Water was released from the Zipingpu dam to avert the threat of a collapse. In addition to the risk of dams bursting, there is the risk of floods from landslides where water builds up and then breaks through.

Making up the shortfall

As a result of Guangdong's earlier power shortages, efforts have been made to increase power generation from gas and fuel oil. Guangdong is not yet connected to China's main pipeline gas infrastructure, so additional gas for power generation has to be sourced from the country's single operating LNG terminal in Dapeng, which has capacity of 3.7 million tons/year. However, power generators have been allocated only 55% of the terminal's contract gas and together have only around 4,200 MW of capacity.

This means that marginal supply comes predominantly from imported fuel oil, as Guangdong is far from China's main coal basins. However, here too China faces problems. Rocketing crude oil prices have led to equally steep rises in fuel oil costs. As electricity tariffs are controlled, rises in the import price of either spot LNG or fuel oil can quickly make power generation uneconomic. Rising domestic coal prices have also added to generation companies' woes and four of the country' five largest generation companies were reported in May to be in the red.

In Guangdong, the government had already put in place subsidies for power generation fuelled by spot LNG or fuel oil purchases. Under the directive, effective March 1, the funding for the subsidy comes from a Yuan 0.045/kWh (0.6 cents/kWh) fee levied on large industrial electricity consumers in the six cities of Guangzhou, Zhuhai, Foshan, Huizhou, Dongguan and Zhongshan.

The subsidy is in addition to a fuel cost pass-through policy announced in February. The policy allows gas-fired plants to receive a higher electricity settlement price for gas purchased at up to Yuan 4/cubic meter (55 cents/cu m, or $15.30/MMBtu) at the end-user's gate. Industry sources said that would net back to a price of around $14/MMBtu for spot LNG cargoes at Dapeng.

While the damage from the earthquake is still being assessed, it appears highly likely that west-east power flows will be limited as Guangdong reaches its summer peak power demand period, exacerbating the expected shortfalls in supply. This means industrial shutdowns will be more widespread and longer lasting than had been predicted. In addition, it will mean rising fuel oil imports as generators struggle to supply power. In turn, if fuel oil prices remain high – and of late May they were hitting record highs alongside crude – this will incur greater costs to the Guangdong authorities through their subsidization of gas and fuel oil for power generation.

CCS – scam or solution?

The goal of energy policy, simply put, is to meet energy demand and reduce emissions, but without serious impacts on security of supply or disastrously damaging rises in energy prices. The question for Carbon Capture and Storage – and for the coal industry more broadly – is whether CCS can play a role in achieving these goals, or whether funds would be better spent elsewhere.

Proponents of Carbon Capture and Storage argue, with good reason, that future power demand cannot be met without coal. And if the emissions cannot be avoided, then it follows that CCS is a necessity. In its 2007 World Energy Outlook, the International Energy Agency forecast that coal's share in primary energy supply would in fact rise over the period to 2030 from 25% to 28%, reflecting the largest absolute increase for any one energy source. This implies a large increase in carbon dioxide emissions and the IEA was clear that the outlook with regard to coal and emissions had worsened in 2007 from the position in 2006.

Environmental group Greenpeace predictably takes a contrary view. In May, the organization released a report describing CCS as a "scam". "It is the ultimate coal industry pipedream," the report said. "It is insanity verging on criminal negligence to pass up clean energy and instead pin hopes on an unproven technology. Governments and businesses need to reduce their emissions, not search for excuses for continuing to burn coal." The report claimed that coal and power companies are exploiting the notion of so-called "capture-ready" power plants to justify building new coal-fired units with no guarantee that CCS would ever be retrofitted to capture their CO2.

The language and position of Greenpeace's report are no surprise, but the idea that capture ready plants are being sold on a false promise is shared by some in the industry. The capital cost of retrofitting and the decline in power plant efficiency that accompanies it have led some industry representatives to describe it as a "politician's fantasy". Where plants are operating under an emissions trading scheme, as in the EU, and in all likelihood soon enough in the United States, the additional cost of investing in CCS will have to be weighed against the penalty price of producing CO2, suggesting a very high value being placed on emissions and consequently higher power prices. Either that, or the cost will have to be underwritten by some other form of state support. Whichever way, a major drawback of CCS is that large amounts of money will be spent to burn coal less efficiently.

Options without coal

Greenpeace's report said that, "Futile investments in CCS threaten to starve existing clean renewable energy initiatives and energy-saving efforts of much-needed funds to ensure that dangerous climate change is prevented." The report outlined the substantial amounts that various governments are proposing to set aside for CCS projects.

However, supporters of CCS argue that neglecting investment in CCS would benefit not so much renewables but natural gas. They argue that if coal-fired generation is limited by emissions schemes, then the most likely market response – and one that is already evident – will be an ever greater reliance on gas. For Europe, this would mean a corresponding decrease in security of supply as its dependence on imported gas rises faster. For the US, it would hasten the predicted increase in LNG imports, exposing it to international supply-chain risks. And gas isn't cheap these days either.

Funding for CCS and energy efficiency measures as proposed in legislation being promoted by US Senators Joseph Lieberman and John Warner, means, according to their analysis, "that natural gas generation would not show up as a bridge fuel". They argue that "if CCS or nuclear is constrained below projected expansion levels in the real world, gas generation would likely fill the gap." Greenpeace is opposed to both CCS and nuclear.

EU parliament reaction

In response to Greenpeace, Chris Davies, the MEP appointed rapporteur for a proposed EU directive on CCS said, "the Greenpeace report is a mixture of inaccuracies and distortions tied together to fit an agenda that takes no account of reality. . . If we are to fight the menace of global warming we have to deal with life as it is, not how Greenpeace would like it to be."

The following day, Davies proposed that power generators who install CCS should get double credits under the European Emissions Trading Scheme. One credit would come from not having to buy an EU Allowance for the carbon stored, while the second would be awarded for each ton stored and could then be sold. The cost would be funded through the ETS, so that rather than resulting in an increased emissions cap, the price of existing EUAs would have to rise, he said. He argued that the extra support was needed to kick-start investment in CCS.

He also proposed that the EU should adopt mandatory targets for CCS, which had been considered by the European Commission, but ruled out on cost grounds. He suggested that all new fossil-fired plants approved from 2015 should be equipped with CCS technology, adding that existing plants should be retrofitted by 2025. The proposals will go before the all-party Environment Committee of the European Parliament, which is to vote on the issue in October. The committee would then start negotiations with the French presidency, which will head the EU Council of Ministers during second-half 2008.

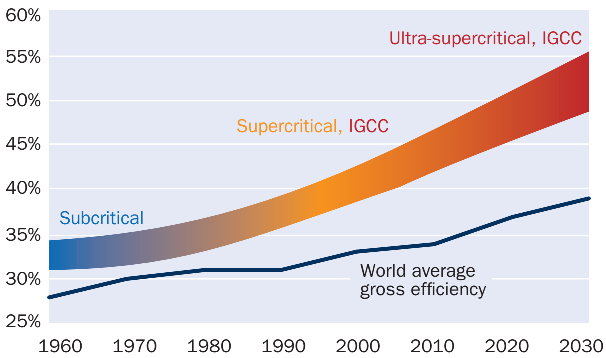
Common ground

However, there was some common ground between Davies and Greenpeace. Both regard CCS as not forming part of the long-term solution to climate change. "While I agree with Greenpeace on the need for a total transformation [of energy production], we just don't have the time to bring about the necessary changes", Davies said, adding that CCS was a "temporary measure; a stepping stone to buy us time to get to zero-carbon energy production."

"We talk about the need for renewables and for energy saving, but as long as we build coal-fired power plants, we will never get to grips with the problem of global warming... Every new coal-fired power plant built in the traditional way should be regarded as a failure of our policy for tackling global warming," Davies said.

Proponents of clean coal technologies do not generally see themselves as paving a road towards coal's total displacement, rather they want to ensure the future of coal as the world's most abundant and widely distributed energy source. As they see it, coal is essential long-term. CCS might be a temporary stepping stone and provide a breathing space to develop new ways of dealing with emissions, but it might also be a viable technology lasting up to a century or more.

Thermal efficiency of coal-fired power generation



Note: The multi-coloured line shows efficiencies for state-of-art plants on a net electrical output, lower heating value basis.

Source: WEO

Electric power emissions as a % of total US emissions, 2006

Coal	32.9
Natural gas	5.8
Oil	0.9

Source EIA

Given that coal provides about 20% of the world's primary energy supply and 40% of electricity generation – rising to 50% in the US, 78% in China and 93% in Poland – it is clear there can be no quick displacement of the dirty fuel. But if CCS is just a temporary solution, then spending huge amounts of money on an uncertain technology that will ultimately burn coal less efficiently, ought to be put to close scrutiny.

The question does need to be asked whether the money directed towards CCS could be better spent elsewhere. For Greenpeace the answer is of course yes; on renewables and energy efficiency measures. However, there is little faith within the power generation industry that either of these options – while critical elements in tackling climate change as a whole – can provide sufficient capacity or savings in usage to displace coal. It would instead add urgency to the 'dash to gas'.

However, CCS money might be better spent on improving the efficiency of the existing coal fleet so that fewer emissions result from each ton of coal consumed, while carbon intensive power production is also penalized under cap and trade schemes.

Coal plant efficiency varies greatly, depending on age and technology. For pulverized coal plant, efficiency ranges from 29% to 39%, while modern supercritical plant can achieve up to 46% and ultra-supercritical 50-55%, according to the World Coal Institute. Moreover, where applicable, combined heat and power operations can raise average plant efficiency to as high as 70-75%, and up to 95% at times of peak usage.

Displacing a low efficiency coal plant with a high efficiency one provides the option of either producing more power from the same amount of coal (and emissions) or producing the same amount of power with significantly lower coal usage (and emissions). And it does not incur the high costs associated with CCS.

Creating new markets

Moreover, it doesn't follow that if coal-fired power is essential, then CCS is the only answer. The other option is to find new uses for CO2. The gas is already used in solid and liquid form for refrigeration, for the storage of carbon powder and in fire extinguishers. The metals industry uses it for the manufacture of casting moulds, and it is also employed in some welding processes. In the chemicals sector, it is needed for methanol and urea production, while in the food sector it carbonizes drinks and is used to decaffeinate coffee. It can also be used in aerosol cans, replacing more harmful greenhouse gases. Next to water, malt, hops and yeast, CO2 is the fifth ranking raw material for producing beer.

However, the global market for CO_2 in industry is relatively small. It was estimated at 152.6 million tons a year in the IPCC's Special Report on Carbon Capture and Storage, published in 2005, slightly less than the UK's annual emissions for 2004. The figure excluded CO_2 injection for Enhanced Oil Recovery. About 60% of the total came from urea production, while only 20.6 million tons had potential for storage over a period longer than a decade. Most processes result in a fairly quick release of the CO_2 back into the atmosphere, although in the case of water treatment the CO_2 becomes a carbonate.

Small volumes of CO_2 are delivered in cylinders, while larger amounts are delivered in liquid form by bulk carrier. Larger users might have their own production plant or receive it by pipeline. The CO_2 is sourced from various processes, for example as a by-product of ethanol production. US company Sutton Gordon quoted a price of 8-10 US cents per lb based on delivery as liquid by bulk carrier, with a yearly volume of between 400,000 to 500,000 lbs. This equates to \$176-\$220 per metric ton, or €113-142/mt, as oppose to the mid-May EU ETS price of €24.85/mt.

In the EU, the use of CO_2 in industrial processes is not incorporated within the ETS, although there is a possibility that this will change post 2012, when the third phase of the scheme comes into effect.

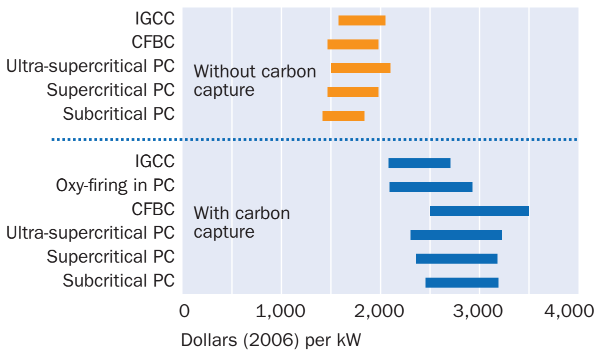
However, there are new technologies being explored that might provide for alternative uses. The common thread is finding a renewable source of energy and hydrogen to bring the cycle full circle and turn CO_2 back into a hydrocarbon or other useful material.

Algae to biofuels takes a biological route. According to US company GreenFuel Technologies Corp, its technology uses naturally occurring algae to recycle the carbon dioxide in power or industrial plant flue gases into biodiesel. The company, which is not alone in developing algae to biofuels technology, has a partnership with South African company Global Renewable. The algae when introduced to a rich carbon source propagate exponentially, the company says.

A key limitation is access to water, but a number of companies, such as PetroSun in the US, believe they can produce the algae in water and on land that would not otherwise be used for food production. PetroSun's first algae-to-biofuels facility was expected to start operation in April in Rio Honda, Texas. It consists of 1,100 acres of saltwater ponds that the company expects will produce 4.4 million gallons of oil and 110 million pounds of biomass annually.

A second pathway is the use of solar energy converted to electricity, which is then used to split CO_2 into carbon monoxide and oxygen. The process has three steps and uses a nickel-based catalyst. Chemists at the University of California say they have demonstrated the feasibility

OECD coal-fired power plant investment costs



Sources: IEA and EPRI databases; MIT (2007); IEA (2006c)

Coal dependents – % use of coal in electricty generation in 2006

Poland	93
South Africa*	93
Australia	80
China	78
Israel*	71
Kazakhstan*	70
India*	69
Morocco*	69
Czech Republic	59
Greece	58
USA	50
Germany	47

*2005 data

Source: World Coal Institute

of the process, although it still requires an additional energy input. Moving to a gallium-phosphide semiconductor, it is hoped, will increase the electrical charge derived from the sun, removing the need for any additional energy. CO has various industrial applications and can be used to make fuel via steam reforming.

Novomer, a Cornell University spin-off, has devised a way of making biodegradable plastics from CO_2 and CO. The plastics could be used for supermarket packaging, computer cases, plastic bottles or foam to insulate buildings, according to Novomer president Charles Hamilton. Again the process is catalyst based. The catalyst improves the reactivity of the CO_2 so that less energy is required to turn the CO_2 and CO into polymers. The process involves mixing a liquid metal with CO_2 or CO in a reactor at low pressure, with the end product containing about 50% CO_2 by weight.

These technologies are nascent, but offer possibilities for alternative uses for CO_2, other than storage, that might displace fossil fuels. None are certain to provide a permanent CO_2 sink. However, they all point to a more productive and economic use of CO_2 than CCS, which ultimately might be seen as no more than a very expensive and uncertain form of landfill.

Peak wind? The road to Copenhagen

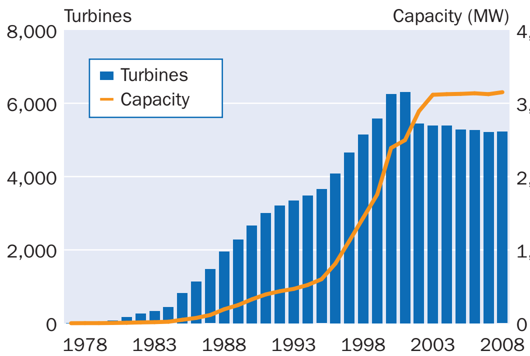
Denmark appears irrevocably wedded to the further expansion of wind, despite the challenges this poses. In fact, the commitment to wind is forcing a new cycle of innovation that could have much wider ramifications. And wind is by no means the only exceptional feature of the country's energy landscape. Having bid to host the World Energy Congress in 2013, Denmark is keen to showcase its technology. **Ross McCracken**

Denmark is a country well used to promoting its green credentials, not least by highlighting the high level of wind penetration in its national electricity system. Wind in 2007 accounted for 19.7% of domestic electricity supply, the highest proportion for wind in the world. However, Denmark also has an extremely high dependence on coal, which provides about half of the country's electricity generation, a proportion on a par with the world's most coal intensive nations. All of this coal is imported. Nevertheless, here too, Denmark can boast that it is one of the world's most efficient coal users.

A further dimension is that Denmark is the only EU nation that is a net oil and gas exporter – for the time being at least. Barring major new discoveries, Denmark has about 16 years of oil and eight of gas, according to the Danish Energy Authority. Exploration drilling has been at a low ebb in recent years, and Danish policy makers are aware that if they are to maintain their current level of energy self sufficiency, they must find a replacement. 2008 has seen just two exploration and appraisal wells in the Danish sector so far, while only seven in total were drilled between 2005-2007.

But it is wind that is Denmark's current trademark and one that has drawn as much criticism as adulation. The extraordinarily high degree of wind penetration is often presented in isolation as a triumph for renewable energy – a green benchmark to which the rest of the world should aspire, but the story is not that simple. The benefits and impact of Danish wind are often overstated by environmentalists not least in downplaying the fact that security of supply and industrial policy were just as important motives in its development, if not more so, than environmentalism.

Growth in number of turbines and capacity



Source: Danish Energy Authority

Equally, critics of the Danish wind experience, who argue that wind has displaced neither hydrocarbon power generation nor carbon dioxide emissions, tend to ignore the valuable lessons that Denmark's headlong rush into wind provides. Both sides tend to omit that wind is not the only exceptional feature of Denmark's energy system and that the Danish experience can only be understood in relation to both the country's national electricity system as a whole, and its position in the wider North European network.

Danish wind

While Denmark's absolute level of wind generating capacity is not that large at 3.15 GW, it is big in comparison with overall generating capacity of about 15 GW. The bulk of turbines are onshore and in the north west of the country. Encouraged by feed-in tariffs, the number of installed turbines accelerated quickly from the late 1970s to peak in 2001. Since then, decommissioning and a near halt to new installations in 2004, owing to growing public opposition and a reduction in incentives, led to a decline in turbine numbers. However, larger capacity turbines and repowering has seen total capacity plateau at just above 3 GW since 2003.

According to Danish Minister for Climate and Energy Connie Hedegaard, legislation passed by parliament in May improving the incentives for onshore wind will see an increase in new installations. Onshore wind is supported by a feed-in tariff paid for by a visible charge on consumers bills called the Public Service Obligation. In terms of the existing electricity system, Hedegaard sees no problem with integrating another 1,300 MW of wind in the next four to five years.

However, any new installations appear likely to be offshore rather than onshore. Local opposition to wind turbines has increased and there is also legislation progressing through parliament that will force wind turbine installers to pay compensation to anyone effected by a new turbine, for example through a decline in land value of a neighboring property. According to Arne Rahbek of Swedish utility Vattenfall, the legislation represents an unknown and potentially large cost for wind developers and one that is only likely to be settled in court. The prospect of legal wrangling and delays over compensation will make new onshore developments difficult.

Offshore, the Horns Rev II development is expected to be commissioned in 2009, adding 209 MW. In addition, Germany's E.ON, in April, was awarded the concession to build a 200 MW wind farm at Rødsand. Offshore wind projects are awarded by means of a tender. The new award includes a subsidy of 0.629 DKr per MWh ($0.130/MWh) for 50,000 peak load hours, which is expected to equate to about 14 years. There are also financial penalties should E.ON decide not to proceed with the project, which is expected to be commissioned in 2011.

Peak wind?

Integrating such a large proportion of wind has proved challenging. The country's electricity system is divided into two parts, in the east it is connected to the Scandinavian Nordel pool and in the west to the west European UCTE area. The bulk of wind capacity is in the north west, where there is also a DC line that connects to Norway.

Critics charge that despite accounting for 20% of Danish electricity generating capacity, wind has not succeeded in displacing any traditional hydrocarbon generating plant. Wind adds electricity to a grid, but, because of its intermittency, does not add reserve capacity. Planners have to take into account the fact that wind will not necessarily blow at times of peak demand.

And the Danish system has another peculiarity; its high degree of combined heat and power plant. The extensive use of CHP makes Denmark a model of efficient energy use, with its most modern coal and biomass plants achieving average efficiency over the year of between 70-75%, and at a times of peak demand up to 94%. This is afforded by decades of investment in district heating systems which provide a ready market for power plant heat that would otherwise be wasted.

However, like wind, this introduces inflexibility into the system. Although there is some leeway in the ratio of heat and power produced, if heat demand is high, a CHP plant will continue to produce power. If this occurs with good wind, then the system overall has surplus power and there is no displacement by wind of more carbon intensive power production.

Multi fuel CHP

Dong Energy's Avedøre power plant, located just 20 minutes from central Copenhagen, is one of the most efficient power plants in the world. With electrical capacity of 810 MW, the supercritical plant boasts efficiency of 46% in its coal-fired unit 1 and up to 49% in the multifuel unit 2. Avedøre is also a combined heat and power plant, providing heat to the extensive district heating system of outer Copenhagen. Over a whole year, unit 2 achieves efficiency of between 70-75%, rising to 91-94% in winter and falling to 45-49% in summer.

Unit 1 was commissioned in 1990 and is a 250 MW coal-fired plant, which cost DKr 2.5 billion ($517 million), including site purchase and harbor construction. Unit 2 was commissioned in 2001 at a cost of DKr 3.5 billion and has total capacity of 580 MWe. The main boiler was originally constructed as a coal-burner, but has been adapted to burn natural gas, fuel oil or wood pellets. It's full load capacity is 395 MWe.

An additional straw powered boiler has capacity of 46 MW and produces steam at the same pressure as that in the main boiler, which can be fed straight in. Burning straw requires a separate boiler because of the fuel's high alkaline concentration which causes corrosion. Two natural gas turbines add a combined 108 MWe and the hot flue gas is used in the heat exchanger to heat up the feed water for the boiler. This process raises the gas turbines' efficiency to 59%. According to Bent Petri, the plant's senior director, a 35 MW reduction in power provides a gain ten times that in heat. The plant also has two district heating accumulators to store hot water.

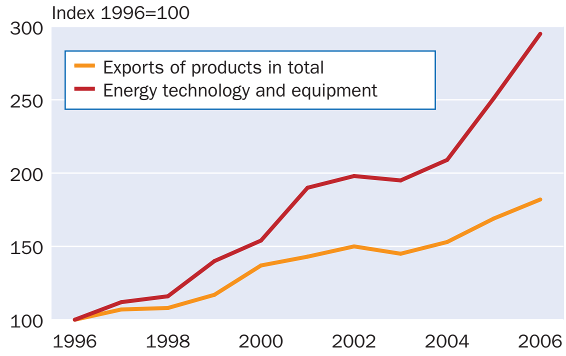
Imported coal for the plant is unloaded at a separate site and then reloaded on to barges for transit to Avedøre's shallow harbor. The wood pellets also arrive by ship, predominantly from Baltic countries. DONG buys the wood pellets on a spot basis and they are dry stored on site. The wood pellets are crushed to make dust and the wood dust blown into the boiler, using the same process as for pulverized coal. Unit 2 typically uses 250,000 tons of wood pellets a year, but this will rise to 400,000 tons this year, owing to a lack of straw.

Straw for the biomass boiler is collected from all over the island of Zealand and its neighbors to the south. DONG has contracts with 500 farmers, who store the straw on their farms, reducing the amount of dry storage space needed at the plant. When required, the farmer is phoned up and lorries dispatched the next day to collect. At full capacity, the plant receives 60 lorries each day, each carrying 45 large bales of straw, which are unloaded into two hangars, where their weight and humidity are measured.

DONG commissioned its first straw burning CHP plant in 1988. The 4 MW plant achieved efficiency of 23%. This was followed by a second plant with capacity of 10 MW and efficiency of 25% in 1995. Raising the boiler temperature and pressure paid dividends and the next plant commissioned in 2000 had capacity of 11 MW, with pressure of 19 bar and temperatures of 540 degrees Celsius. Efficiency rose to 29%. The Avedøre unit marked a step change. Raising the pressure to 300 bar and temperature to 580 degrees Celsius, and scaling up to 46 MW, saw electrical efficiency rise to 42%. Although designed for 150,000 tons of straw a year, in 2007 the plant used 171,000 tons.

The farthest the straw travels is 150 kilometers and the energy consumed in transport equates to 4% of the energy gained, according to DONG. The plant typically runs all year except for July. Subsidies are key to the use of biomass. Heat from biomass receives an advantage through the differential tax structure levied depending on fuel type. Tax is highest on coal, lower for natural gas and zero for biomass. Burning straw for power receives a subsidy of DKr 7.5-15 per kWh and would not otherwise be commercial, according to Petri.

Exports of energy technology and equipment, and products in total



Source: Danish Energy Authority

Danish international interconnections

New links are being planned: Norway to western Denmark Skagerrak IV (letter of intent); Great Belt (internal) Zealand-Funen (decided). Potential external reinforcements include Western Denmark-Netherlands, southern Denmark-Germany, Germany-eastern Denmark.

Source: Stattnet

This highlights the critical importance of export capacity accompanying Denmark's high degree of wind penetration. Denmark has five international interconnections, totaling export capacity of about 4,520 MW, almost a third of total generation installed – a proportion every bit as exceptional as wind's 20% of generation capacity.

Even if bottlenecks and congestion are taken into account, all of Denmark's wind capacity could be exported, if necessary. As it is mostly produced in the north west of the country, Danish wind power is exported either south to Germany, where it would displace more carbon intensive energy production, or north to Norway where it competes with hydropower.

This latter option has been derided by critics as the ultimate irony – that Danish wind 'displaces' another renewable, but in fact it is one of its greatest advantages. Hydro power is not displaced but conserved through higher reservoir levels. In effect, pump storage without having to pump. Danish wind producers also maintain that there is a good correlation between wind and rain. i.e. the wind blows more in dry weather and less in wet, when hydro power flows are maximized.

Moreover, hydro has near instant start-up, making it perfect for dealing with peaks and troughs in wind speed. If a system has a high proportion of wind and nuclear, for example, it provides a low carbon mix, but would also require coal or gas to create a spinning (and emissions producing) reserve for speedy start-up when the wind fails. By contrast, wind and hydro are a marriage made in heaven.

But that is not the end of the matter. It's not that the wind sometimes doesn't blow, but that it often blows at the wrong time. If there is low demand in either the Norwegian or German systems when Danish wind power is available, for example at night, then the export price is very low. In competing with hydro, high-cost renewable electricity is replacing low-cost renewable energy.

The irony is that the advantage accrues to the Norwegian hydro owner, or in the case of export to Germany, through lower German emissions and electricity prices, both ultimately courtesy of the Danish consumer. The predominant load flow is in fact from Denmark south to Germany, although sometimes limited by congestion, rather than to Norway, where hydro power is cheap.

Denmark energy production and consumption 2007 (petajoules)

	Production	Consumption	Balance	% of production	% of consumption
Crude oil	652	345	307	57.6	39.8
Natural gas	346	176	170	30.6	20.3
Coal	0	196	-196	0.0	22.6
Waste, non renewable	9	9	0	0.8	1.0
Renewables	125	141	-16	11.0	16.3
Total	1,132	867	265	100.0	100.0

Energy consumption adjusted for climate variations and net electricty exports

Source: Danish Energy Authority

Danish wind's dependence on its international interconnections also raises the question of whether neighboring countries could raise their level of wind penetration to the same degree. This could both negate the advantages Denmark currently enjoys from its interconnections and amplify the problems associated with wind integration across a wider area. Proponents of wind argue that different wind conditions across a larger geographic area would start to smooth out the peaks and troughs. This might be true to a certain extent, but it ignores the reality that large weather systems can and do settle over northern Europe.

Nevertheless, by integrating so much wind power into its system, or rather the wider north European electricity system, Denmark has already succeeded in challenging and changing previous conceptions about wind. And by raising its wind capacity further, it hopes to do so again. In one sense this is being driven by industry. Wind has been a success for Denmark not just in terms of energy production, but in terms of jobs and energy exports; in fact more so for energy products than power, where the energy balance is small.

Wind turbine manufacturers are now amongst the country's largest employers and growth in energy exports has outstripped other exports by a significant margin. This is the renewable energy industry model that governments across the EU would love to emulate and one which the Danish government sees as essential to managing the decline in oil and gas. As such, there is a powerful lobby in Denmark that wants to push wind forward regardless.

However, the existing commitment to wind is itself promoting a further cycle of innovation in dealing with the problems of integrating decentralized and intermittent sources of energy into a national system. This can be seen in terms of system management, investment in new international interconnections and most particularly in terms of energy storage. While Denmark is experimenting with various forms of storage, such as vanadium batteries, there appears to be a widespread view that plug-in hybrid electrical vehicles provide a realistic pathway within the next decade, and one which has the significant added benefit of simultaneously reducing oil consumption.

Denmark's state-owned energy company DONG announced in April a partnership with Project Better Place, a US-based firm, to introduce electric cars on a large scale. The cars would be charged overnight when power prices are low, providing a market for surplus wind power. The cars are to be supplied by a Renault-Nissan partnership using lithium-ion batteries, although car manufacturers in Scandinavia are also developing electric and hybrid vehicles. Such thinking, driven by the desire to retain energy self sufficiency and create new industries, can be seen as a virtuous circle of innovation whose roots can be traced directly to the oil supply crises of the 1970s and Denmark's early adoption of wind technology.

Waste to energy

Waste incineration plants are rarely popular with surrounding populations, but can provide an effective means of reducing landfill, while at the same time producing both heat and power. Denmark has 29 waste to energy plants.

One such plant is Amagerforbraending, which is owned by its local municipalities. The plant takes in 440,000 tons of municipal, household and industrial waste a year and reduces it to about 20,000 tons of hazardous waste for landfill. In the process some 80,000 tons of bottom ash is recovered, which is sold on to the construction industry. About 5,000 tons of recovered metal provides an additional income stream.

Overall, 65% of waste is recycled, 8-9% ends up in land fill and the remainder is incinerated to produce, in 2007, 202.179 MWh of power from two steam turbines and 2.984 TJ of heat. The first 20 MWe turbine was built in 1990 and an 8 MWe turbine was added in 2000, although the plant itself is 37 years old and due for replacement. Turbine efficiency is low at 25% and the operating parameters (380 degrees Celsius and 40 bar) are limited by the corrosive effects of burning waste.

Amagerforbraending's four incinerators can each burn 15 tons of waste an hour. They start up on waste, needing no additional fuel supply and are fed by huge automated grabbers. The plant has a catchment area comprising a population of 535,000 people and 40,000 businesses and institutions, within which it is entitled to all waste. There is a tax of 44 euros per ton on incineration and 50 euros per ton on landfill. Recycling is tax free. The plant is obliged to incinerate all waste than can be incinerated and is currently having to store about 30,000 tons a year, owing to lack of capacity.

Heat and power are sold on the commercial market, although the plant has contractual obligations to provide heat, which takes precedence over power output. The plant's carbon dioxide emissions are not measured because waste incineration has been deemed CO2 neutral, although other emissions are strictly monitored.

Amagerforbraending is supposed to cover its costs rather than make a profit. In 2007, the plant made 9.8 million euros ($15.1 million), of which 6.3 million euros was reinvested. Revenue came from 8.9 million euros in tipping fees, 6.8 million from a per capita municipal levy, 17.6 million from district heating, 10.9 million from electricity sales and 2.3 million from the sale of recycled materials. An additional 11 million euros came from the repayment of waste tax and miscellaneous items. Production and administration costs for the year amounted to 47.5 million euros. Overall, the plant produces power at a price of 0.05 euros/kW, about 50% higher than the market price.

Rejuvenating northern Borneo

The fortunes of northern Borneo, one of the world's earliest commercial oil provinces, are being rejuvenated as deepwater oil discoveries in the South China Sea come on-stream. Faced with declining output from more mature areas, Malaysia's state oil company Petronas hopes that by 2015-2020 this deepwater frontier will add up to 300,000 b/d of crude and 1 Bcfd of gas to national output. **Andrew Symon** reports

Since the early 1980s, Malaysia's economic progress has been closely entwined with the success of the petroleum industry. But the sector's future contribution to GDP is likely to fall. Projections over 20 to 30 years show Malaysia moving from net oil exporter to net importer, alongside absolute declines in total oil and gas output as the main fields offshore the eastern coast of Peninsular Malaysia are depleted. Current oil reserves are expected to last 19 years, while natural gas reserves at current rates of production should last 33 years.

In response, the government and state oil company Petronas are promoting the upstream potential offshore Sabah and Sarawak. New deepwater frontier blocks are being offered to foreign companies under production sharing terms with Petronas. Acreage closer to shore and onshore, which is relatively under explored or where previously non-commercial discoveries may now prove viable, is also being promoted.

In the current Ninth Malaysia Economic Development Plan (2006-2010), the government says that "continuous efforts will … be undertaken to attract international oil companies to invest in exploration activities particularly in deepwater of more than 200 meters and ultra deepwater of more than one kilometer to increase domestic petroleum reserves."

Deepwater frontier

The shallow waters of Southeast Asia and its archipelagos have long been abundant sources of oil and more recently natural gas. Production from deep water, that is depths of more than 200 meters, is comparatively rare. But large discoveries in traditional areas have dwindled and, as elsewhere in the world, it is hoped that deep water exploration will start to uncover large, new reserves.

Two deepwater provinces already promise new production that will partly offset the region's forecast decline in oil output; offshore Sabah and its neighbor Brunei, the tiny petroleum-rich Islamic Sultanate, and to the west the Makassar Straits that lie between Indonesian Kalimantan on Borneo Island and the island of Sulawesi.

In the Makassar Straits, the first discoveries were made in the late 1990s by Unocal, which was acquired by Chevron in 2005. Indonesia's first deepwater field, West Seno, at a depth of 800 to 1,000 meters, started producing oil and gas in 2003. Further to the east of Indonesia towards New Guinea, there is also deepwater that may have potential, although to date there has been little exploration.

Offshore Sabah, US company Murphy Oil is leading the way with the Kikeh field, which came on-stream in August 2007, becoming Malaysia's first deepwater operation. The field is located in Block K, about 210 kilometers west of Sabah's state capital, Kota Kinabalu, in water depths of 1,300 meters. Production is expected to peak at an average of 120,000 b/d by end-2008, equal to about 20% of Malaysia's total oil output in 2006. Murphy Oil is operator with an 80% interest, the rest being held by Petronas. Crude from Kikeh is delivered to a Floating Production, Storage and Offloading facility for further processing and storage before being loaded on to tankers for export.

The next deepwater field on-stream should be Shell's Gumusut-Kakap field, which was discovered in 2004 in water depths up to 1,200 meters. The field lies mainly in Malaysian Block J, but extends into the adjacent Block K. Shell has a 33% stake in the field, ConocoPhillips 33%, Petronas 20% and Murphy Oil 14%. The final investment decision to develop the field was taken in January. Planned to come on-stream in 2011, peak production is expected to reach 135,000 b/d from 19 subsea wells. Also under development is the Malikai field in Shell's adjacent Block G. Other discoveries with commercial potential have been made on the block.

Oil from Gumusut-Kakap will be processed offshore and then piped to a new oil and gas terminal under construction at Kimanis, 45 km south west of Kota Kinabalu. The terminal is to be operational by 2010 and will complement the existing Sabah Gas Terminal, the Labuan Crude Oil Terminal and the Labuan Gas Terminal. Targeted to serve Gumusut-Kakap and other new deepwater production, the terminal will have capacity to handle 300,000 b/d of crude and 1 Bcfd of natural gas.

Elsewhere in Sabah, Australian resources group, BHP Billiton, boasting deepwater expertise gained from its operations in the Gulf of Mexico, has joined the hunt for new reserves, taking up two deepwater exploration blocks in March 2007. Blocks N and Q are located 175 km off Kota Kinabalu in water depths of 1,600 to 2,800 meters. The blocks are in the same basin as the Kikeh, Malikai, Gumusut-Kakap and other discoveries. BHP holds a 60% operating interest in both blocks, while Petronas owns the remaining 40%. BHP is to start exploration in July. For BHP, the Borneo thrust marks a return by the company to serious petroleum exploration in Southeast Asia.

Up until the deepwater awards, Northern Borneo had remained something of a Shell fiefdom. In Brunei, Shell has virtually monopolized the petroleum industry since it began operating the country's first oil field, Seria, onshore in 1932. In partnership with Petronas, and the Brunei Sultanate, Shell continues to have the largest interests of any foreign company in the region, although Murphy Oil has quickly built up a strong upstream position. In Sarawak, Shell is a major gas producer for the 23 million ton per year Bintulu LNG plant, as well as a partner in its operation with Petronas and Japanese companies. At Bintulu, Shell has also pioneered the world's first commercial 14,000 b/d gas-to-liquids plant.

Deep water gas not ignored

As the new Sabah oil and gas terminal indicates, the value of deepwater natural gas is not being ignored. Associated gas from the Kikeh field is already being commercialized with the sale of 120 MMcfd since January to Petronas' methanol plant on Labuan island off the southwest coast of Sabah.

Another deepwater gas development is the Kebagangan cluster of fields about 130 km north west of Kota Kinabalu, which is operated by Shell (30%) in partnership with ConocoPhillips (30%) and Petronas (40%). A production sharing contract has been carved out for the field cluster within Shell's block J. Gas supply is earmarked for the new Sabah Oil and Gas Terminal at Kimanis.

Murphy also made deepwater gas discoveries in 2007 to the north east of Kikeh in Sabah's Block H, in which Petronas also has a 20% stake, at depths of 1,000 meters. Murphy says gas production could begin by 2012.

Plans for the commercialization of Sabah gas are ambitious. Petronas aims to land the gas at Kimanis and then pipe it 500 km overland through Sabah and neighboring Sarawak to the Bintulu LNG facility at a cost of $620 million. Pipeline construction, the tender for which was awarded in March, will be no mean feat. The route must pass through rugged mountain terrain and over rivers before running along the more benign Sarawak coastal plain to Bintulu. Nevertheless, the pipeline's construction, which is scheduled for completion in 2011, would provide an export route for gas that will make Sabah more attractive for investing companies."

Earlier, and arguably technically simpler, proposals for commercializing the gas through supply to Brunei's Lumut LNG facility, run by Shell, and much closer to Sabah, seem to have been abandoned, as has the idea of a maritime pipeline route through Brunei waters with the sultanate receiving a transport tariff.

Mature redevelopment

The shallower waters closer to Sarawak and Sabah (and Brunei) have long been areas of oil and gas production. Petronas is promoting new exploration here both in under-explored areas and in fields which higher oil and gas prices might now make economic. A priority is to ensure sufficient long-term supply of gas for the Bintulu facility. Supporting this goal, Murphy Oil has signed new gas supply agreements to commence in first-half 2009 from offshore blocks, Blocks SK309 and SK311.

Also taking a position in the shallow offshore regions of Sabah is Kufec, a subsidiary of the Kuwait Petroleum Corp, which now has interests in three Sabah blocks. In addition, Swedish independent, Lundin Petroleum, took up three offshore exploration blocks in April. This covers areas previously operated by Shell and includes one undeveloped gas discovery.

An onshore revival may also follow if a new award by Petronas in Sarawak to Nippon Oil of Japan proves fruitful. Nippon, in partnership with Petronas, was awarded in December onshore block SK333 in the Baram area near the city of Miri, the site of the state's

Crude oil and natural dry gas production in South East Asia

	1980	1984	1988	1992	1996	2000	2004	2006	2007
Crude oil including lease condensate, ('000 b/d)									
Brunei	235	160	130	165	155	193	178	200	n.a.
Burma	30	32	13	14	8	12	20	23	n.a.
Indonesia	1,577	1,412	1,342	1,504	1,547	1,428	1,096	1,019	964
Malaysia	283	440	540	653	695	690	755	613	588
Philippines	15	12	6	8.05	2	1	25	25	n.a.
Thailand	0.3	18	36	51	61	110	155	204	n.a.
Vietnam	0	0	15	106	175	316	403	344	314
Total	2,141	2,074	2,082	2,501	2,993	2,750	2,632	2,428	
Natural dry gas production (Tcf)									
Brunei	0.316	0.303	0.304	0.286	0.325	0.349	0.406	0.433	
Burma	0.011	0.023	0.037	0.036	0.057	0.120	0.360	0.473	
Indonesia	0.630	1.059	1.340	1.792	2.354	2.359	2.663	2.613	
Malaysia	0.056	0.325	0.581	0.796	1.230	1.498	2.205	2.218	
Philippines	0	0	0	0	0.0004	0.0004	0.102	0.088	
Thailand	0	0.070	0.193	0.249	0.428	0.658	0.790	0.858	
Vietnam	0	0.002	0.001	0.007	0.029	0.041	0.106	0.162	
Total	1.112	1.782	2.456	3.166	5.197	5.025	6.632	6.845	

Source: US DOE, EIA, April 2008

first oil production in the early twentieth century. About 80 million barrels of oil was produced by the Miri field before the block was relinquished by Shell in 1981.

Petronas hopes that new exploration by Nippon using modern technology in an old oil province might replicate the success of ExxonMobil in Indonesia in central east Java. Here, at depths well below the old wells and workings dating from Dutch colonial times, ExxonMobil in 2001 made one of the country's largest contemporary discoveries, the Cepu oil and gas field. Production is to begin in 2008 with the field expected to peak at 180,000 b/d.

Rush triggers border disputes

The deepwater rush in the northern Borneo/South China Sea region has reignited disputes over sovereignty. The region is more prone than any other in Southeast Asia to competing maritime border claims.

Kuala Lumpur claims that the deepwater blocks awarded by Brunei in 2002 to a Shell-led group including Mitsubishi and ConocoPhillips, (Brunei Block K/Malaysia Block M) and to a Total-Amerada Hess-BHP consortium (Brunei Block J/Malaysia Block L) are in Malaysian waters. Brunei says they are within the boundaries of its Exclusive Economic Zone.

The Brunei blocks, which are considered to be very prospective, extend north west from the mainland in the more distant waters of Brunei's EEZ. Matters came to a head in 2003 when Malaysian gunboats chased off a drilling rig working for Total in waters adjacent to Sabah.

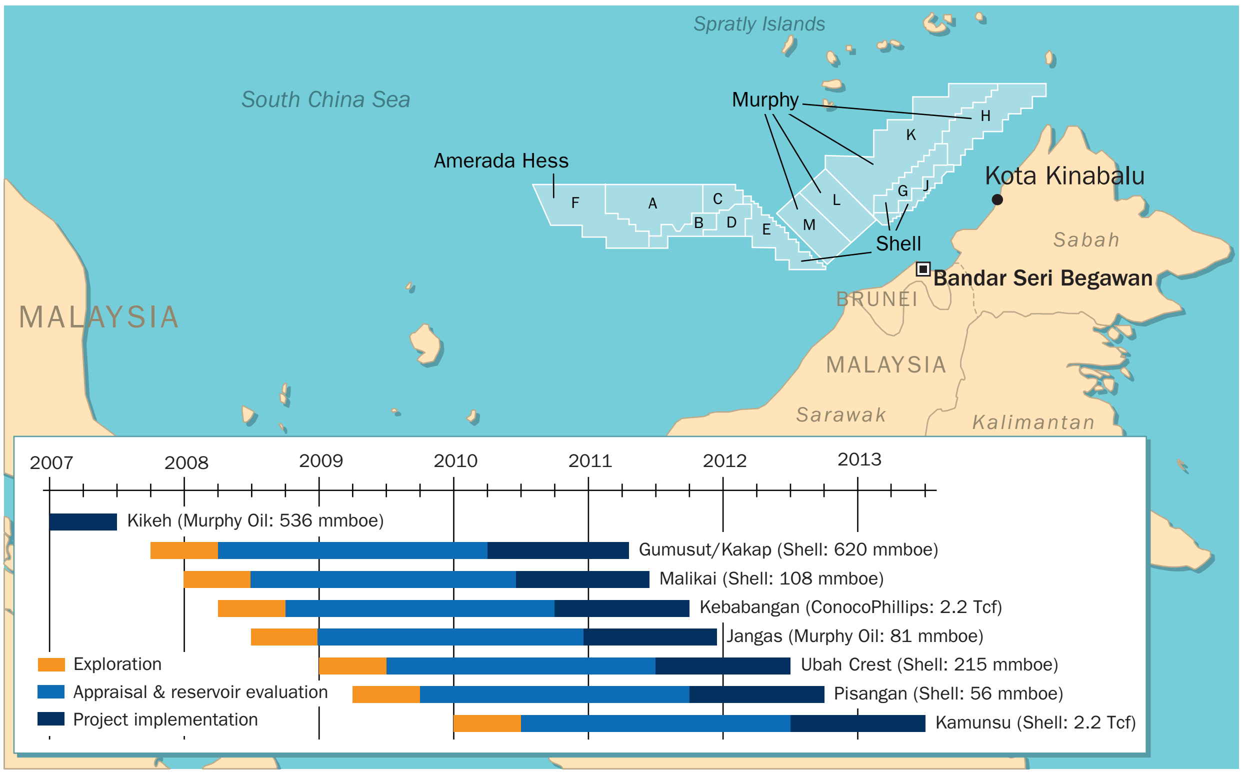
Since then, discussions have quietly gone on between Brunei and Malaysia with little being said publicly.

Last August, there was talk of a joint development approach, but since then nothing further has been revealed. Exploration in the contested waters has been left in limbo with the concerned companies waiting for a resolution. Complicating negotiations, says Jamie Taylor, a Singapore-based analyst for UK consultants Wood McKenzie, is that the Kikeh and Kakap field structures appear to extend west into the waters claimed by Brunei.

However, the main focus of territorial disagreement in the South China Sea is the Spratly islands and atolls, well to the north of the Borneo coast. China's maritime claim in fact extends into waters much closer to Malaysian Borneo and Sarawak to the extent that Murphy's Kikeh and Shell's Gumusut-Kakap fields both fall within its claimed territory. China has not taken issue with these blocks, unlike for example with Vietnamese blocks allocated to BP and India's ONGC offshore southern Vietnam, which Beijing argues are in its territory.

Offshore eastern Sabah, there is also a boundary dispute between Malaysia and Indonesia, triggered by Malaysia awarding an exploration block in 2005 to Shell which overlaps Indonesia's Ambalat block. In 1999, Indonesia awarded at least part of the contested area to Italy's Eni and then later to Unocal in 2004. The dispute has also seen stand offs between the Indonesian and Malaysian navies. Like the Brunei-Malaysia situation, the state of negotiations between Kuala Lumpur and Jakarta is closely guarded.

North Borneo deepwater oil projects



Source: Innovation Norway, Murphy Oil

Forthcoming conferences

16th European Biomass Conference and Exhibition
June 2-6
Valencia, Spain
www.conference-biomass.com

4th Russia/CEE ChlorVinyl Markets
June 3-4
Kiev, Ukraine
www.cmtevents.com

PowerGrid Europe
June 3-5
Milan, Italy
www.powergrideurope.com

PowerGen Europe
June 3-5
Milan, Italy
www.events.pennnet.com

Renewable Energy Europe
June 3-5
Milan, Italy
www.renewableenergy-europe.com

CIS Coal Summit
June 3-5
Moscow, Russia
www.adamsmithconferences.com

Caspian Oil & Gas Exhibition and Conference
June 3-6
Baku, Azerbaijan
www.caspianoilgas.co.uk

Energy Trading Central and Eastern Europe
June 4-5
Bucharest, Romania
www.energytradingcee.com

Russia and the Kyoto Protocol
June 4-5
Moscow, Russia
www.pointcarbon.com

Non-edible Feedstocks for Biodiesel
June 5-7
Chennai, India
www.inc-global.com

Biofuels Markets Asia
June 9-10
New Delhi, India
www.greenpowerconferences.com

World Biofuels Forum
June 10-11
Prague, Czech Republic
www.wtevents.com

Energy Ireland 2008
June 11-12
Dublin, Ireland
www.energyireland.ie

11th Annual Private Power in Central America
June 12-13
Panama City, Panama
www.platts.com

Oil and Gas Markets of Central Europe
June 14
Prague, Czech Republic
www.cenergy.eu

Nanotechnology for Sustainable Energy
June 14-19
Obergurgl, Austria
www.esf.org/conferences

Eurelectric Annual Convention and Conference 2008
June 16-17
Barcelona, Spain
www.eurelectric.org/Barcelona2008

Financing Nuclear Power
June 18-19
London, UK
www.smi-online.co.uk

IAEE International Conference
June 18-20
Istanbul, Turkey
www.iaee08ist.org

Energy Talks Ossiach 08
June 18-20
Ossiach, Austria
www.energytalks.com

Central and Eastern European Power Forum
June 19-20
Warsaw, Poland
www.c5-online.com

Vietnam Energy & Power 2008
June 19-20
Hanoi, Vietnam
www.inc-global.com

Platts Oil Forum
June 23
Moscow, Russia
www.platts.com

CIRED Seminar 2008: SmartGrids for Distribution
June 23-24
Frankfurt, Germany
www.ciredsmartgrids.org

Nuclear Industry Forum
June 23-24
London, UK
www.marketforce.eu.com/nuclear

5th Annual Utility M&A
June 23-24
New York, USA
www.platts.com

Carbon Markets Asia
June 23-25
Singapore
www.greenpowerconferences.com

Asian LPG Seminar
June 23-26
Singapore
www.purvingertz.com

6th Russian Petroleum and Gas Congress
June 24-26
Moscow, Russia
www.russianpetroleumcongress.com

Asian Oil and Gas Show
June 25-27
Seoul, South Korea
www.asiaoil.com

District Energy/CHP 2008
June 29-July 02
Orlando, USA
www.districtenergy.org

World Petroleum Congress
June 29-July 03
Madrid, Spain
www.19wpc.com

3rd Annual European Nuclear Power
June 30-July 1
London, UK
www.platts.com

Central Asia Mining Congress 2008
June 30-July 1
Almaty, Kazakhstan
www.terrapinn.com/2008/camining/

Gas Storage 2008
June 30-July 1
London, UK
www.smi-online.co.uk

2nd Nuclear Energy Finance Forum
July 1-2
London, UK
www.euromoneyenergy.com

Coal-Gen Europe
July 1-3
Warsaw, Poland
www.coal-gen-europe.com

10th Africa Energy Forum
July 2-4
Nice, France
www.energynet.co.uk

Kazakhstan Growth Forum
July 2-4
London, UK
www.adamsmithconferences.com

Global Conference on Global Warming
July 6-10
Istanbul, Turkey
www.gcgw.org

Energex Vienna 2008
July 6-10
Vienna, Austria
www.energex2008.com

Biomass '08 Power, Fuels and Chemical Workshop
July 15-16
Grand Forks, USA
www.undeerc.org/Biomass08/default.asp

LETTER FROM SANTIAGO: MAY 2008

Chile faces battle to develop hydropower

Rolling into the Chilean capital on the swift new toll-roads that symbolize the country's dogged drive towards development, one billboard in particular captures the visitor's eye. The soaring granite peaks of the Torres del Paine mountains, the best known image of Chile's wild, largely untamed south, is almost completely blotted out by a stern row of electricity pylons. "Patagonia Sin Represas" (Patagonia without dams) the slogan demands.

It is just part of a major publicity campaign, backed by an alliance of Chilean and foreign environmentalists, that opposes plans by some of Chile's largest companies to harness the huge potential of Patagonia's raging rivers. HidroAysen, a joint venture between power companies Endesa Chile and locally-owned Colbun, plans to invest $3 billion over the next decade to build five hydroelectric dams on two rivers in Chilean Patagonia with installed capacity of 2,750 MW. Mining group Xstrata also plans a further 1,500 MW on the nearby Cuervo river

There is no doubt that Chile's needs the electricity. According to government forecasts, the country's power consumption is set to double by 2020, requiring 12,000 MW of new capacity. The loss of natural gas imports from neighboring Argentina, facing its own self-imposed energy crisis, has meant a huge re-engineering of Chile's energy sector. Combined with low rainfalls last year, the country faces the possibility of power rationing later this year, especially if the recent period of dry weather doesn't change.

Companies are expected to invest $21 billion in coming years, largely in new coal-fired power plants and two LNG terminals that by early next decade should end the country's reliance on gas supplies from across the Andes and imports of diesel, a temporary but expensive replacement. But business leaders fear that these new power sources will leave the country highly vulnerable to swings in international coal and gas prices, both of which have been chasing oil to new heights. That could see Chile losing out in the battle for regional investment against rivals Argentina, Brazil and Peru where, thanks to domestic resources and subsidies, electricity prices are significantly lower. High power prices have already closed a ceramics factory in Santiago and led papermaker CMPC, a stalwart of the Chilean economy, to switch planned investment to Peru.

Taming the wilds of Patagonia

The many rivers which crisscross southern Chile have potential to support 20,000 MW of hydro capacity, of which less than a quarter have been exploited to date. Following drought-inflicted power cuts in the late 1990s, the government turned cold on hydropower with just one major project, Endesa Chile's 690 MW Ralco plant being developed in the last decade. The country's current power shortage has reversed this position.

Much of Chile's remaining hydropower potential lies in Aysen, where the country's thin blade fragments into spectacular fjords, forests and glaciers. Not only do the region's rivers promise plenty of power, but they are free from the droughts that afflict rivers further north every ten years or so. Aysen only began to be settled in the 1950s and remains remote: there is still no paved highway to the rest of the country and many Chileans were shocked to see residents being evacuated by ferry in freezing temperatures when the nearby Chaitén volcano erupted on May 2. Despite the spread of salmon farming and the destruction of swathes of forest for cattle-grazing, Aysen represents to many Chile's last frontier, largely untouched by man's destructive influence.

No surprise then that an alliance of Chilean and foreign environmentalists have promised to use every means possible to prevent the Aysen hydroelectric projects becoming reality. Foremost among them is Douglas Tompkins, a Californian clothing entrepreneur-turned-environmentalist, who has spent millions of dollars buying up pristine rainforest and mountains to protect them from farming and forestry. Tompkins' involvement has given campaigners against the dams some powerful connections.

The New York-based National Defense Council has given its backing to the movement, with the group's lawyer Robert Kennedy junior earning an exclusive meeting with Chilean President Michelle Bachelet. Other groups in the US are urging home improvement stores to boycott timber produced by CMPC, which is owned by the same Matte family that controls Colbun. A New York Times editorial published in April, entitled Patagonia Without Dams, criticized the project for threatening to "irretrievably damage one of the wildest and most beautiful places on earth" and called on the government to consider other forms of renewable energy instead.

The Chilean government is already seeking to boost investment in renewables with a new law requiring 5% of power to come from wind, biomass and other sources by 2010, but these will only supply a fraction of the country's power needs, says Colbun CEO Bernard Larrain. HidroAysen, he insists, is an efficient answer to Chile's energy problems. The proposed dams will flood just 6,000 hectares in exchange for 40% of the power required on central Chile's SIC grid.

But even more difficult may be approval of the 2,000 kilometer transmission line to transport power from Patagonia to the country's demand centers, crossing seven of Chile's administrative regions and hundreds of landowners, including national parks and indigenous communities. After the controversies surrounding the Ralco project, when ministers circumvented environmental rules and ran roughshod over the rights of indigenous people, the government has promised to remain neutral in the upcoming approval process. Nevertheless, given what is at stake, it is ultimately likely to be a political decision.

Tom Azzopardi

LETTER FROM WASHINGTON: MAY 2008

Legislators target energy price 'speculators'

Whether record oil prices are the result of evil speculators or the more fundamental supply/demand situation may be debatable, but there is no doubt that high prices hit a raw political nerve. There is also no doubt that US legislators can at least be seen to be doing something about speculation, whereas they have little power to change oil market fundamentals. Their constituents, they believe, want action, and they have obliged with a flurry of legislative measures designed to address speculation of any hue both at home and abroad.

For a start, the comprehensive farm bill seems destined to become law, with or without the president's signature. The Senate passed the $306 billion bill by an 81-15 vote in May, the day after the House approved the measure by a vote of 318 to 106. Although President George Bush subsequently vetoed the measure, the bill passed both chambers by more than the two-thirds majority required to override him.

The bill reauthorizes the Commodity Exchange Act, which contains a provision closing the "Enron loophole" that has prevented the US Commodity Futures Trading Commission from fully overseeing electronic markets, such as the IntercontinentalExchange. Deeming the farm bill a "major legislative victory," Senator Dianne Feinstein, a California Democrat, told a Washington press briefing that the bill ultimately would deter "unscrupulous traders" from engaging in excessive speculation and curtail manipulation of energy futures prices. Senator Byron Dorgan, Democrat-North Dakota, said the measure was just one step toward ending what he views as "an orgy of speculation" in energy futures trading.

Specifically, language in the farm bill would give the CFTC the authority to police electronically traded contracts that serve a significant price discovery function. Among other things, it would require exchanges to monitor trading of such contracts and give them the authority to reduce the size of positions in order to prevent excessive speculation. It would also create an audit trail by requiring them to supply large-trader reports to the CFTC. The primary target of the bill is the Henry Hub natural gas financial swap contract, which is traded on the IntercontinentalExchange and settles off the traditional NYMEX gas futures contract.

Other measures to curtail speculation have focused more exclusively on the petroleum markets, where prices have soared to record levels on an almost daily basis for the past several months. Earlier in May, Feinstein and fellow Democrat Carl Levin of Michigan introduced the Oil Trading Transparency Act, which would require foreign exchanges to meet, as US exchanges do now, speculative-trading limits to prevent price manipulation and excessive speculation, as well as publishing daily trading information.

In addition, on May 7, Senator Harry Reid of Nevada and other Senate Democrats introduced the Consumer-First Energy Act, a separate bill that would require the CFTC to set a "substantial" increase in margins that investors must pay in advance to purchase crude oil contracts. Feinstein said a study by Levin's office suggested speculators are adding between $20 and $25/barrel to the price of oil. "With oil at $125/barrel, this energy sector is a very fragile one . . . even after the Western energy crisis," Feinstein told reporters.

But the CFTC has defended the activities of speculators, with officials reiterating the commission's longtime stance that they have beneficial functions, such as providing liquidity, and do not necessarily push commodity prices higher in general. In oil, officials said, the number of commercial and noncommercial entities has remained fairly constant over the past 22 months, even as prices have surged to record highs. In the case of natural gas, Jeffrey Harris, the CFTC's chief economist, and John Fenton, director of market surveillance, told a House subcommittee that increasing demand for gas-fired generation has served as the primary support to prices, which are averaging about 73% higher, compared with 2005. US Energy Secretary Samuel Bodman has also denied theories that speculators – or financial investors depending on your viewpoint – have affected the price of oil, instead pointing to the demand/supply situation as the primary cause.

However, this has not stopped Democratic lawmakers from passing a bill to allow the US to take legal action against OPEC, if the oil cartel were found to be conspiring to fix prices, a move the White House has threatened to veto. The Gas Price Relief for Consumers Act of 2008, also known as the "No Oil Producing and Exporting Cartels Act of 2008," or "NOPEC," was passed by a vote of 324 to 84. The bill would make it illegal for any foreign state collectively to limit oil or natural gas production or to act to control its price, in effect allowing the attorney general to bring OPEC to court in the US.

The White House sent a letter May 19 that said passing the legislation would "likely spur retaliatory action against American interests in those countries and lead to a reduction in oil available to US refiners." Bodman said, "NOPEC is an effort on the part of Congress to try to force the exporters of oil to be more forthcoming, and I think it's an error." He said, if he were Saudi Arabia, he would pull out of investing in American projects such as the Motiva Refinery expansion in Port Arthur Texas. Bodman added that there is "nothing that can be done near term," to relieve the rising price of oil.

Perhaps not, but that doesn't seem to wash with US legislators keen to crack down on speculators, whether of the home grown variety or those that form cartels internationally.

Washington staff

LETTER FROM MOSCOW: MAY 2008

Prime Minister Vladimir Putin speaks

Russian government plans to cut the tax burden on the oil sector in a bid to increase the country's production and refining capacity are gathering momentum. Moscow aims to finalize its plans by August, according to Vladimir Putin, who stepped down as president in May, only to take up the position of prime minister.

"I believe that by August at the latest we should make final decisions on the strategy and tactics of a further reduction of the tax burden, when and by how much the taxes should be reduced," Putin told the Duma, Russia's parliament, presenting the future government's plans for economic development in the country. "It is time to make decisions on cutting the tax burden in this sector," Putin said.

The first four months of the year saw a 1% year-on-year decline in oil output due to depletion of Russia's resource base, prompting concerns that the country's annual oil production may fall this year for the first time since 1998. Putin said that although oil companies enjoy high revenues, the Russian budget takes some 75-80% of their income, mainly through the mineral extraction tax and export duty, which results in more "low-flow wells, and slows down the exploration and development of new fields."

Russia's finance ministry has said that the tax burden on the oil sector would be cut by some $4 billion a year, mainly through a reduction in the mineral extraction tax. But this falls far short of what oil producers think is necessary. They have called for a reduction of at least $25 billion a year to help with the development of new projects. Analysts expect the actual cut to be a compromise of between $10 billion and $15 billion a year.

Putin has proposed seven-year tax breaks for new oil fields in the Timan-Pechora and Yamal Peninsula regions, as well as for offshore fields to stimulate exploration and crude production. Russia has already introduced ten-year tax breaks for new fields in East Siberia, which came into effect in January 2007. Among other measures, Putin has also proposed a cut in taxation for depleted fields and a new system for oil product excises. The better the quality of the products, the lower the excise should be, he said.

Putin also announced in May that Russia's new president Dmitry Medvedev had appointed a cabinet of ministers. Changes have been made to the structure of the government, with some ministries being reorganized and their functions revised, he said. In particular, Russia's industry and energy ministry has been split into two ministries, with Sergey Shmatko, the former president of state-owned nuclear equipment and services company Atomstroyexport, appointed energy minister. Former industry and energy minister Viktor Khristenko was appointed industry and trade ministry, Putin said.

Favorable business climate

"The easing of the tax burden is a significant incentive for the establishment of a favorable business climate in the country," Putin said. The prime minister also focused on further increasing business freedoms, saying the government would start "large-scale work" to remove excessive red tape. Putin highlighted his intention to transform Russia into a leading financial center, which would require changes in financial market legislation.

Putin said the government would stimulate Russian investments abroad, but complained that foreign markets have often being closed to Russian investment. "According to international independent research, last year our companies lost opportunities to invest in the economies of developed countries by around $50 billion due to political decisions by those countries," he said. "Foreign investments into the Russian economy are currently . . . some ten times higher than ours abroad," he commented, adding that "we have to react" to the limiting of access for Russian investments by other countries.

Presumably part of the reaction, Putin also thanked the Duma for backing the recently adopted law on regulating foreign investment in strategic industries, especially in such "sensitive" sectors as development of major hydrocarbon fields classified as "strategic." "We will do everything on a parity basis," he said. Putin had earlier in May signed into law the long-awaited bill on foreign investments in Russia, which grants the right to develop major fields only to entities in which Russian capital exceeds 50%.

Restricting majority foreign-owned investment in Russia might be seen as a strange way to encourage openness in others. But no doubt BP will be one company that will benefit from the more favorable business climate espoused by Putin. Russia's Federal Security Service raided BP's office in Moscow on May 20, the second such raid in two months. While the offices of TNK-BP, the Russian joint venture in which BP has a 50% stake, were not raided, there has been increased pressure on the company in recent months amid speculation that the government is trying to force the sale of a stake in the company to state-owned Gazprom.

Earlier in May a Russian court issued an injunction prohibiting the activities of BP experts seconded to TNK-BP. TNK-BP said the injunction by the Tyumen regional court was a result of a lawsuit filed by a minority shareholder, brokerage Tetlis, to annul an agreement with BP to use the UK company's experts on secondment to TNK-BP. To abide by the injunction, the BP employees have stopped their work at TNK-BP. BP considers the injunction to have no legal merit. In addition, in April, it emerged that Russia's tax authorities had hit TNK-BP with fresh tax claims for 2004-2005 totaling Rb6 billion ($257 million).

Moscow staff

LETTER FROM BRUSSELS: MAY 2008

It's not over till it's over

The European Commission's controversial proposals to separate energy grids from supply and generation businesses, known as 'unbundling', contained in its draft third EU power and gas market opening laws, have dominated debate in Brussels for months and there is no let up in sight. May saw two key votes by the European Parliament's energy committee, but few are ready to bet yet on what the EU's preferred market model will look like when the dust finally settles.

First up to face a formal vote was the draft power law on May 6. On the table were the Commission's preferred options: full ownership unbundling, an independent system operator, or the so-called "third way" championed by France and Germany, which would allow parent companies to keep control of their grids under strict regulatory supervision. No-one could say for certain which way the vote would go – only that it would be very close. And it was – the committee narrowly rejected the third way with 26 votes against, 22 for and three abstentions.

It also rejected the Commission's second choice, the independent system operator model, for being too bureaucratic. That left full ownership unbundling as the only option for the power sector under the draft text the committee sends forward to be voted on by the full parliament in mid-June. UK centre-left MEP Eluned Morgan said she was "fairly confident" that parliament would back the committee's text. Morgan is responsible for leading the parliament's debate on the draft EU power law and negotiating with the Commission and EU Council on agreeing a common text. The committee vote largely followed national rather than political party lines, she said, and if that held true in the full parliament the text would be adopted by an even stronger majority.

New option for gas emerges

Gas, however, is a different matter. The parliament has consistently supported the idea that the EU's gas sector – which is heavily reliant on a few external supplier countries like Russia and Algeria – has special needs. Until now the Commission has just as consistently argued that the problems in the power and gas sector need similar solutions. But there are signs that the Commission is ready to reconsider in order to break the deadlock in the Council, where the eight anti-ownership unbundling countries, led by France and Germany, control just enough votes to block the draft laws.

In the run up to the committee's formal vote on the draft gas law on May 19, the Commission circulated an informal compromise proposal based on the third way, which would allow parent gas companies to keep control of their grids under certain conditions. The Commission's energy spokesman, Ferran Tarradellas, stressed that the compromise on gas was only because of its specific technical problems.

But the Council's desire to treat the gas and power markets in a similar way is likely to favor the anti-ownership unbundling countries, if a third way-based compromise is found for gas. "Maybe once the gas issues are solved, it will be much easier to find a compromise on power," Tarradellas told reporters in Brussels.

MEPs back gas compromise

Back in parliament, the energy committee's members scrambled to include the Commission's latest ideas for gas in compromise amendments to be considered in its formal vote on the draft gas law. This time the voting was even closer. The committee rejected the third way again, but by the tightest of margins – 24 votes for versus 24 against. A majority is required to accept. And it again rejected the independent system operator idea.

But it backed, by 38 votes to 10, the Commission-inspired compromise that would give EU governments the option of allowing parent companies to set up independent transmission operators as an alternative to full ownership unbundling. Described by one Commission official as a "beefed up third way," this new option would allow parent companies to keep their grids as long as they gave their independent transmission operator subsidiaries "effective decision-making rights," among other conditions.

But even this result is not yet fixed, as in an unusual move the committee decided not to vote on the final text including the amendments. "As long as we don't hold a final vote, we can continue discussions," said the committee's chairwoman, German centre-right MEP Angelika Niebler. That means the committee could still vote through changes before the text goes forward to be voted on by the parliament as a whole in mid-June.

Meanwhile, discussions continue in parallel at the Council, where the current Slovenian presidency of the EU is hoping to reach a political agreement on the main points of the draft laws at the next EU energy ministers' council on June 6. The Commission was prepared to work closed with the Council, the Slovenian presidency and the parliament ""to find a political compromise that's acceptable to all in order to have real unbundling," Tarradellas said, before the committee vote on the draft gas law. And the Commission was still confident that this compromise would be reached at the next EU energy council, he said.

Despite the various votes, at this stage only two things are sure; every word of the eventual compromise will be wrestled over right to the bitter end, and the anti-ownership unbundling countries retain an advantage, owing to the tight timetable for passing the draft laws by early 2009.

Siobhan Hall

Market News

Prices hit tipping point for consumers and subsidy regimes

Each dollar rise in the price of crude oil is increasing the amounts spent by governments on fuel subsidies. Even in countries where subsidies are not in place, heavy taxes on fuel are being questioned as consumers see more and more of their disposable income eaten up by energy costs. Having absorbed crude's rising price in recent years, governments and consumers appear to have reached a critical point at which subsidy regimes cannot be sustained and at which governments are starting to respond to consumer protests.

The options for changing subsidy regimes are not pleasant. If they cannot be maintained, governments have little choice but to pass more of the cost of rising energy prices directly on to consumers. This will stoke inflation and increase energy poverty and potentially result in social unrest. However, it should make demand more responsive to price rises, which is critical if the 'price mechanism' is to be restored. Supported by subsidies, demand for oil continues to grow in Asia and the Middle East, despite record prices, when the price signals suggest it should be falling, as it is in the OECD.

By contrast, reducing tax on fuels in response to consumer pressure will serve to moderate the demand response to high prices. France has suggested suspending valued added tax on oil sales, an idea frowned upon by the European Commission, while a senior German politician said he wanted the G8 to prohibit financial speculation in oil markets. In the UK, road haulers have staged a number of protests, while French fisherman have blockaded refineries.

The fiscal effect of reducing fuel tax is hard to evaluate as it would support higher sales volumes, or in the current case limit demand destruction. However, if current fuel tax rates are taken as a base, cutting them will interfere with the price mechanism and can be seen as having a similar impact to introducing a subsidy – higher demand at the expense of government finances. This might be politically expedient, but it is unlikely to help the oil market or consumers in the long run.

China's strong economy appears for the moment to be able to sustain huge subsidies to its refiners. Beijing has dismissed rumors that it will change its current pricing system. In the Middle East, subsidies are being balanced by higher export revenues from crude itself.

However, other countries can no longer put off the inevitable tough choices. In Malaysia, rising crude prices have pushed the government's cost of subsidizing fuel way past its spending on development, according to Malaysia's Deputy Prime Minister Najib Tun Razak. This, he said, means that a review is necessary and the government will make changes to its subsidy regime.

Indonesia, which has announced that it will leave OPEC, raised gasoline and gasoil prices by 33% and 28% respectively effective May 24 to ease its ballooning subsidy spending. Consumers in Taiwan will have to pay 20% more for transport fuel starting June 1, and pay higher electricity prices from July, after the government decided May 22 to lift a freeze on domestic fuel and power prices. India's Petroleum Secretary M. S. Srinivasan said May 23 a fuel price increase was "inevitable" to bail out state-owned refiners and marketers facing a cash crunch. New Delhi is considering fully deregulating domestic gasoline prices.

It appears that a tipping point is being reached in both subsidy-ridden countries and those that have heavy taxes on fuel. It also appears that the responses may be contradictory in impact; on the one hand moving towards restoring the price mechanism by reducing subsidies, while on the other hand reducing taxes in an effort to limit the effect of high prices.

Country-by-country breakdown of OPEC production (million b/d)

Country	April	March	February	January	December	November	Current target
Algeria	1.390	1.390	1.390	1.390	1.390	1.390	1.357
Angola*	1.850	1.900	1.900	1.850	1.800	1.780	1.900
Ecuador**	0.500	0.500	0.490	0.500	0.500	0.518	0.520
Indonesia	0.860	0.860	0.860	0.830	0.840	0.830	0.865
Iran	3.940	3.960	3.930	3.980	3.970	3.950	3.817
Kuwait	2.550	2.550	2.550	2.550	2.540	2.500	2.531
Libya	1.750	1.740	1.740	1.740	1.740	1.720	1.712
Nigeria	1.800	2.020	2.100	2.100	2.200	2.200	2.163
Qatar	0.830	0.840	0.830	0.830	0.830	0.830	0.828
Saudi Arabia	9.100	9.150	9.150	9.200	9.020	9.000	8.943
UAE	2.590	2.590	2.590	2.590	2.500	2.150	2.567
Venezuela	2.330	2.350	2.400	2.400	2.400	2.400	2.470
OPEC-12	29.850	29.850	29.930	29.960	29.730	29.268	29.673
Iraq	2.380	2.370	2.400	2.290	2.300	2.400	N/A
Total	31.870	32.220	32.330	32.250	32.030	31.668	N/A

* Angola joined OPEC on January 1, 2007. An output allocation of 1.9 million b/d was assigned at OPEC's December 5 meeting in Abu Dhabi and came into effect on January 1. **Ecuador resumed its OPEC membership in November. An output allocation of 520,000 b/d came into effect on January 1. EIA data from Aug-Nov 2007.

Source: Platts

Tensions rise between TNK-BP shareholders

BP confirmed May 27 that there were disagreements between the British and Russian shareholders in its 50:50 joint venture TNK-BP – a rift analysts expect will lead to changes in the company's ownership within a year. "We are aware and deeply disappointed by the current situation," a BP representative in Russia said.

The comments came a day after TNK-BP's CEO Robert Dudley first revealed there were disagreements, in particular regarding investments in Russia and abroad, as well as over the possible sale of some Russian assets. TNK-BP is 50% owned by BP and 50% owned by a group of Russian shareholders: Alfa (25%), Access Industries (12.5%) and Renova (12.5%).

With discussions dragging on about a transfer to state-owned gas company Gazprom of TNK-BP's stake in the huge Kovykta gas field in East Siberia, market experts have said recent spying and tax charges made against BP may have been aimed at increasing the pressure on the Russian shareholders to sell their stakes in TNK-BP to Gazprom.

Although the JV and its various shareholders have repeatedly denied they were in talks over a possible change in TNK-BP's ownership structure, many market observers believe they have already agreed to let Gazprom enter the company. The long-waited deal is likely to be sealed within the year, they have said. The real reason for the current problems between shareholders is the unresolved question of who is to sell stakes to Gazprom, according to Konstantin Simonov, head of Russia's National Energy Security Fund. Each side fears the other may be in separate talks with Gazprom, he said, adding that all the other disagreements between the shareholders are a result of this underlying conflict. "It is absolutely clear that sooner or later control over TNK-BP is to be transferred to a state-run company," Simonov said.

A source close to some TNK-BP shareholders suggested Dudley was forced to make the disagreements public as he felt he was losing control over the company, threatening TNK-BP's normal activity. Dudley said he could not rule out a fall in the firm's crude oil output in 2008 from last year's level because of ongoing problems over the use of BP experts.

The source said that intentional mistakes in documents submitted to Russian labor authorities in May could result in further problems for BP employees working in the country. "The move was done in the interest of some shareholders who want to reduce the number of foreign specialists working for the company," he said. In the documents submitted by TNK-BP's executive director German Khan, a representative of the Russian shareholders, the quota of foreign specialists working directly for TNK-BP was reduced from 150 to 63, the source close to shareholders said. He added that Khan, who was not responsible for human resources, had no right to submit such a document.

Mexico's Cantarell output falling twice as fast as forecast

Production at the giant Cantarell complex in the Sound of Campeche – long the mainstay of Mexico's crude output – slumped by 33% year-on-year in April, twice as fast as the decline forecast for this year by state-owned oil company Pemex, energy ministry figures show. Production from Cantarell in April was 1.074 million b/d, half its peak of four years ago and the lowest since secondary recovery by nitrogen injection began at the turn of the millennium. Cantarell's decline is only partly being offset by increased production from other fields.

In April, Pemex produced 2.767 million b/d of crude, down 13% from the same month of last year, while crude exports dropped by 14.3% year-on-year to 1.439 million b/d. Production dropped year-on-year each month in 2007, as it has now for 2008. Mexico's crude output peaked at 3.38 million b/d in 2004; this year so far it has averaged just over 2.87 million b/d. Crude exports have followed a similar pattern, falling by about 500,000 b/d between 2004 and this year. More than 80% of crude exports go to the United States.

Late last year, the energy ministry published a document warning that Mexico's days as a major crude exporter were numbered unless deregulation and fiscal reforms – along with better management of Pemex – could release the nation's oil potential. The ministry's 2007-2016 prospectus for crude predicted that, if Pemex continued to work under its present constraints, crude output would fall from 3.26 million b/d to 2.14 million b/d. At the time, the ministry was criticized in some quarters for scaremongering, but so far reality is proving worse than its forecasts.

The ministry predicted crude output of almost 3.1 million b/d for this year; the decline to current levels was not supposed to happen until 2011. Yet Pemex officials remain optimistic. In a recent conference call on the company's first-quarter results, Carlos Morales, the director-general of Pemex's upstream subsidiary, insisted that output of 3-3.1 million b/d could still be achieved by year's end. And, despite the fall in the volume of exports, they are currently earning Pemex some $4 billion a month, at least twice as much as in 2004.

That is good news for the government, which depends on oil for a third of its income, but it may take some of the steam out of President Felipe Calderon's proposal for energy reform. These aim to leave the door slightly ajar for private-sector exploration in deepwater – the area on which Pemex is pinning its hopes for the future, but where it lacks the know-how and financial muscle to go it alone. Calderon launched the proposal early in April in the hope that it would be approved by Congress by the end of the month. But a vociferous opposition movement persuaded legislators to hold a "national debate," similar to US public hearings, on the issue in the Senate through July.

Nigeria seals oil loans and claims arrears

Nigerian President Umaru Yar'Adua has ordered the state-owned Nigerian National Petroleum Corporation to recover payment arrears of $850 million from Shell and $646.3 million from ExxonMobil regarding the development of the offshore Bonga and Erha fields, respectively. Yar'Adua also directed that $414.6 million in gas sales accruable to NNPC and the government from Bonga be recovered.

The government directive is in line with the recommendations of the Oil and Gas Reform Implementation Committee, set up by Yar'Adua to determine whether Nigeria has been losing money through the production sharing contracts that govern its deepwater offshore oilfields, the government said.

However, the implications of the government's new policy may well go beyond just arrears claims. "The president will soon unveil his broad agenda for the total restructuring of the oil and gas sector in line with his vision to turn it from a mere extractive industry to one that adds tangible values to the overall economy of the country," his office said in May.

The government says a major revision of the existing levels or structure of oil taxation is recommended, especially given the present need to retain and increase investor confidence in Nigeria. But industry players fear that the ongoing industry reforms would further devastate the existing operating agreements, especially at a time of high oil prices.

Nigeria's PSCs were agreements born in response to the funding problems faced by old joint venture arrangements, many of which dated back to the 1990s when oil was below $20/barrel. An energy reform report drafted by the OGIC said the terms of Nigeria's PSCs have been variable, complex and too excessively in favor of the contractor. The government also did not envision the present key role of gas as a revenue earner when it awarded the PSCs to foreign companies.

Under the PSCs, the contractor, usually a foreign oil company, bears the entire cost and risk of exploration activities and only reaps the rewards after a commercial discovery. The risky nature of operating in this manner paid off with discoveries of giant fields such as Bonga, Erha, Chevron's Agbami and Total's Akpo.

However, the government is also pursuing loans from oil companies to address NNPC's funding shortfalls. NNPC has signed a $3.1 billion oil financing agreement with Shell, comprising $1.3 billion to cover the shortfall in the government's 2008 equity contributions and a "bridge loan" of $1.8 billion to finance NNPC's outstanding payments for 2006/07 joint venture cash calls. The deal follows a $2 billion loan signed with ExxonMobil and another for $1 billion with Total.

Shell said that after "over 50 years of successfully partnering with the government", the company is operating "in full compliance with the laws and regulations of the country." But added that "We would like to reinforce that, following recent statements relating to retroactive changes to fiscal terms, we are very concerned about the future potential implications for investor confidence in Nigeria."

Indonesia to exit OPEC

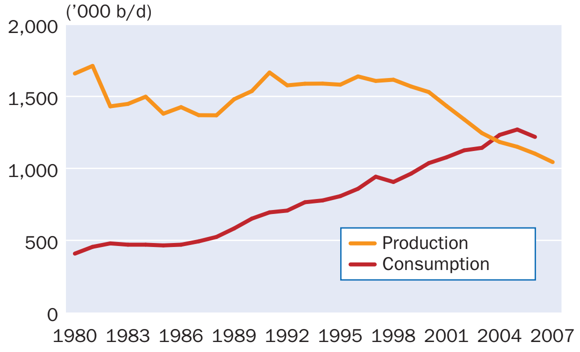
Having gained two new members in recent years, Angola and Ecuador, and assiduously courting Brazil, OPEC is to suffer one casualty – Indonesia. The country has decided to withdraw from OPEC membership, oil minister Purnomo Yusgiantoro said May 28. "During the budget planning meeting, the president [Susilo Bambang Yudhoyono] said we have to withdraw from OPEC ... Probably when I go back to office, I will sign that we withdraw from OPEC," Purnomo told reporters in Jakarta.

Indonesia is expected to quit the cartel from January 2009, as it has already paid its membership dues for 2008. OPEC had said the country was welcome to stay. However, Indonesia was "not happy" with the current high oil prices, Purnomo said, referring to Indonesia's ballooning fuel subsidy bill, which totaled nearly $10 billion in 2007, 60% higher than budgeted.

Nevertheless, Indonesia leaving OPEC is unlikely to make much difference either to the organization or to oil market supply, while its subsidy regime will remain a matter of internal policy. The country's crude output fell close to 1 million b/d in 2007, while consumption has been above the 1 million b/d mark since 2000. Proved reserves have also been on a downward trend, reaching 4.37 billion barrels at the start of 2008.

Indonesia has consistently been unable to meet the targets OPEC has set for its production, but in so doing has provided scope for other members to produce above target without compromising the group's total production goal. Indonesia has no spare capacity above current production and there is no reason to expect a rise in the country's output as a result of it leaving OPEC.

Indonesia turns net importer of crude



Source: EIA

US producers push for extended biodiesel subsidy

US biodiesel producers will continue to lobby for an extension to tax breaks on their industry beyond 2008, despite the subsidies becoming the focus of a formal trade complaint from European biodiesel makers, according to a US National Biodiesel Board official. European biodiesel producers submitted a formal anti-dumping complaint to the EU competition watchdog in Brussels in April, claiming the US subsidy has fueled a wave of cheap imports that has severely hit the European biodiesel industry.

"The unfair competition from US B99 is price-setting and has progressively disrupted the margins of European biodiesel producers, putting most of them out of business. Consequently, the important EU biodiesel production capacity has remained largely unutilized in 2007 and production has increased at a much lower rate than in the previous years," the EBB said

The NBB rejects the claims, blaming the woes of European biodiesel producers on high prices for rapeseed oil feedstock and the scaling back of biodiesel subsidies in Germany and France.

US tax credit

The US biodiesel blenders tax credit, created in 2004, provides up to $1/gallon to those blending petroleum diesel with biodiesel, whether it is sold domestically or exported. US exports of the so-called "B99" blend biodiesel, which can contain less than 0.1% of conventional diesel, and also qualifies for EU subsidy regimes, exploded by more than tenfold last year to some 1 million mt.

Without an extension, the US subsidy expires at the end of this year, but US producers and soy growers have been lobbying Congress hard, warning of a collapse of their industry if the tax break dries up. "The biodiesel incentive is working, and extending the credit is a top industry priority," NBB's Vice President for Federal Affairs Manning Feraci said.

However, the NBB faced a setback in May when the Senate approved the US farm bill, which has been stripped by the Senate finance committee of the latest attempt to extend the subsidy. The removal of a two-year extension clause was seen as a compromise deal to cut the bill's overall tax burden, but Feraci said he believed an extension to the biodiesel subsidy could form part of an "extenders package" for expiring fiscal measures considered before Congress adjourns for the year.

In addition, US President Goerge Bush on May 21 vetoed the farm bill saying that its funding of agriculture programs was excessive and unnecessary at a time of high food prices and record farm income. However, the bill passed both the Senate and House of Representatives with more than a two-thirds majority, enough to overturn the presidential veto.

Imports of US B99 biodiesel, often confused with a "splash and dash" loophole that allows shipments of non-US biodiesel to earn the US subsidy when re-exported to Europe through US ports, currently make up about 90% of biodiesel imports, EU producers claim.

European producers are also skeptical that US lawmakers will allow the subsidy to expire at end-2008, given the powerful farm lobby and the political drive to cut US dependence on imported oil. "There is a good chance that the credit will be extended," the European Biodiesel Board's project manager, Amandine Lacourt, said. "That is why we have filed the anti-dumping complaint; we can't just wait and see."

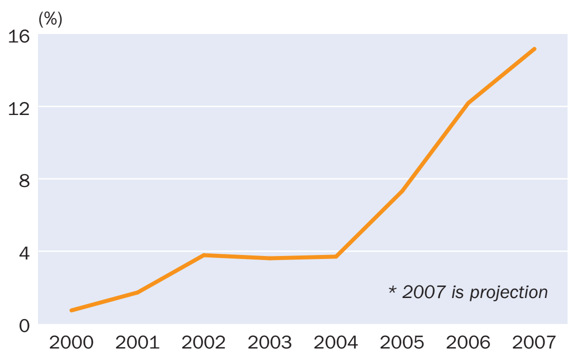
Lacourt said that while in Europe biofuels are subsidized mainly through tax breaks when the fuel is sold at the pump, in the US, the subsidy is available when biodiesel is blended, regardless of whether it is sold on the domestic market or exported. Lacourt estimates that US taxpayers are currently subsidizing European motorists to the tune of $300 million/year, paying for something that is not consumed in the US. "Currently, there is a strong incentive to export to Europe," she said.

One of the European casualties of B99 imports is UK biodiesel maker D1 Oils, which blames the imports for the closure of its biofuels refining and trading operations earlier this year. "We're not going to bring our plants back online; we're getting out of the downstream element," D1's CEO Elliott Mannis said. "We can't afford to wait on the never, never that this might get fixed at some future point in time... I don't see any end in sight to B99 and this is a very good example of where subsidies don't work."

Looking ahead, the NBB says European producers should be less concerned over US biodiesel exports as the Renewable Fuels Standard is set to soak up 500 million gallons of biodiesel production for domestic sale starting next year. But that may be too late for European legislators if they back the EBB argument that US subsidies are unfair and are damaging local industry.

Under European Commission rules, the competition authority currently has until June 9 to decide whether to launch a full anti-dumping or anti-subsidy investigation on the back of the EBB's complaint. If the Commission agrees that US subsidies are distorting trade and damaging the region's biodiesel industry, it can impose provisional countervailing duties on the US imports within 60 days to nine months.

US percentage of world biodiesel production



Source: F.O. Licht, World Ethanol and Biofuels Report.

South Pars swaps buy time for investors

Iran faces a gas shortage of around 153 million cubic meters per day this winter, the student news agency ISNA reported in May quoting National Iranian Gas Company supply director Mostafa Kashkoulid. This is despite the completion of phases nine and ten of South Pars, and the injection of at least 50 MMcmd of gas from these two phases into the national gas grid.

Last winter, Iran struggled to cope with one of the coldest winters on record, especially after Turkmenistan, supplier of around 5% of Iran's gas, cut exports by 20-23 MMcmd, saying it needed to conduct urgent repairs to its export pipeline. Iran was then forced to cut its exports to Turkey, its only gas export market, to cover the shortfall, but this was still not enough to meet domestic demand. Turkey in response had to source more gas from Russia and on the LNG spot market.

Iran's current natural gas production is around 460 MMcmd. The country expects to add more than 150 MMcmd to output by the end of the current Iranian calendar year (March 19, 2009) with the completion of Phases 6-10 of the giant South Pars gas field.

Iran also looks likely to develop Phases 11 and 13 of South Pars without foreign assistance and use the gas for domestic purposes rather than for LNG exports, according to Nosratollah Seifi, managing director of the National Iranian Gas Exports Company. Seifi said in May that Total, which has delayed making an investment decision on the development of Phase 11, owing to the threat of international sanctions, was amenable to an Iranian proposal to take gas from two other South Pars phases instead. This would allow the Iranians to proceed with early development of Phase 11 themselves. The National Iranian Oil Company holds a 50% stake in Pars LNG, alongside Total (40%) and Malaysia's Petronas (10%). Total reached an agreement with Iran in February 2004 for the development of Phase 11 with the gas destined for the Pars LNG project.

Iran has made a similar proposal to the foreign partners in the Persian LNG project, Shell and Repsol. Iran will develop Phase 13 to produce natural gas rather than LNG as part of an effort to speed up development of areas close to the maritime border with Qatar, Seifi said. Gas from Phase 13 was originally earmarked for the Persian LNG project, but Seifi said it would now be utilized for either household consumption or as feedstock for a petrochemicals plant.

Shell and Repsol have agreed to develop other phases of South Pars some time in the future. The two companies said in May they are "still involved" in the South Pars project. "We are proceeding to block swaps and not withdrawing from the project," Repsol spokeswoman Maria Ritter said. "The Iranian authorities suggested we swap from the offshore block 13 to blocks 20 and 21, and we have agreed," she added.

The massive South Pars gas field is generally accepted as the world's largest single field and extends into Qatar. Development there has progressed much more rapidly, raising Iranian concerns that gas will migrate from its side of the field into Qatar.

Shell and Repsol in early 2007 signed a service agreement with the National Iranian Oil Company to develop phases 13 and 14. Each have a 25% stake in the project, with NIOC holding the remaining 50%. Shell spokesman Adam Newton said the Anglo-Dutch major remained involved though the present deal was different.

The entire South Pars project has encountered numerous delays owing to the sanctions imposed by the EU and US over Iran's alleged development of nuclear weapons, claims Iran denies. Despite that, one industry insider noted that the "project is too important for the energy groups to abandon altogether." The swapping of blocks allows the foreign partners to remain part of the project, but without having to make commitments that might fall foul of sanctions.

Abuja pursues Nigeria first gas policy

The Nigerian government has launched an ambitious drive to attract up to $30 billion in investment from local and international companies to develop the country's natural gas infrastructure. Launching the Nigerian Gas Masterplan Investor Roadshow in Abuja in May, Secretary to the Government Babagana Kingibe said that infrastructure was key to the implementation of the new gas blueprint, which aims to double gas production and supply to the domestic market over the next 12 months.

"Beyond the cost competitiveness, the blueprint also addresses the issue of flared gas and the impact of massive infrastructure investment on the ecology and general environment of the Niger Delta," Kingibe was reported as saying. "A pipeline is proposed to ensure gas availability in the eastern and northern parts of Nigeria, thereby creating a platform for revitalization of industries and the general economy in these areas," he said. Kingibe said the directive would also ensure gas production tripled within 24 months and that there would be a significant impact on the country's electricity supply.

Nigerian President Umaru Yar'Adua's policy, which has yet to be voted into law, has raised concerns over future LNG projects in Nigeria. One project, Nigeria LNG, has said that it may put construction of its seventh train on hold while investors evaluate the new policy, which requires producers to allot part of their output to the domestic market, rather than exporting it. NLNG officials said the engineering, procurement and construction work on the Train 7 Plus project, due to start mid-2008, might be delayed until the new gas policy is confirmed.

The joint venture partners in Nigeria's $6 billion Brass LNG project have also warned of delays, saying that a startup date of 2011 might not be met unless issues delaying a final investment decision are resolved by end-May. The government had yet to meet some "crucial enablers," the partners said.

Gazprom's LNG strategy takes major step forward

Russia's Gazprom is to take all the capacity and a stake of an undisclosed size in a proposed 500 MMcfd Canadian LNG import terminal. The Rabaska deal gives the company a home for the LNG from its Shtokman field, while allowing it to hold out for better prices in other markets as it chooses. Gazprom plans to start LNG supplies from one 7.5 million mt/year train within the Shtokman project in the Barents Sea in 2014. The final investment decision on Shtokman's phase one, to be developed with Total of France and StatoilHydro of Norway, is expected in September 2009.

The Rabaska partners – Quebec gas supplier Gaz Metro, Canadian oil and gas transporter Enbridge and Gaz de France – said they expected to sign definitive agreements by end-2008 with Gazprom's US-based subsidiary. Developing new markets and products is key to Gazprom's global energy strategy, Gazprom deputy chairman Alexander Medvedev said. "Delivering LNG produced at Shtokman to new Atlantic basin gas markets is keenly important to us, and Quebec and Ontario are attractive markets," he added.

Analyst Bob Hastings at Canaccord in Vancouver cited the access to supply as the most important development for Rabaska, underscoring the interest of LNG projects all over North America in courting Gazprom as a potential partner. "It's tough to secure gas supply for LNG facilities these days," said Hastings. Even if Gazprom does not use the capacity all the time, having a permanent foothold in Canada will enable it to trade its production more profitably and reduce the possibility of having to sell distressed cargoes.

This has been the thinking of BG and others who have taken capacity in the US, a trader said. BG has long-term capacity at Lake Charles and Total and ConocoPhillips have capacity at Sabine Pass, ensuring that there is always the option of selling into the US and allowing the traders to hold out for better prices. Cargoes of LNG leaving Shtokman for Canada will have the option of diverting to European terminals.

The president of Gaz Metro, Sophie Broch, called the agreement a "major milestone," adding that the deal connects Quebec to one of the world's largest natural gas fields. The Rabaska partners have already obtained the key federal and provincial government approvals to proceed with building the terminal in Levis and expect to begin receiving LNG shipments in 2014.

Gazprom plans to invest $45 billion up to 2030 in the development of its LNG business. The company's long-term strategy calls for Gazprom to take a 25% share in the world LNG market, or 90 million mt/year, by 2030. Gazprom's first LNG production will come from the Sakhalin 2 project in Russia's Far East. Start-up is scheduled for the beginning of 2009.

Gazprom is the majority shareholder in Sakhalin 2, which consists of two gas liquefaction trains with capacity of 4.8 million mt/year each. The Sakhalin 2 partners have not ruled out a third LNG train at a later stage. Apart from Gazprom, Shell holds a 27.5% stake in the project, with Japanese Mitsui (12.5%) and Mitsubishi (10%). Gazprom may also build an LNG plant in the remote Yamal Peninsula in the north of Russia, again targeting the US market.

Santa Cruz autonomy vote dampens Morales

The Bolivian government, led by President Evo Morales, took over natural gas producer Chaco, controlled by BP, pipeline operators Transredes, owned by the US' Ashmore Energy, and fuel storage and transport firm CLHB, controlled by German and Peruvian companies, in May as part of a continuation of the state's nationalization drive. "Bolivia wants partners, not owners," Morales proclaimed. Morales also declared that the national telephone company that offers service across Bolivia and is run by Euro Telecom International, a subsidiary of Telecom Italia, was also nationalized.

In May 2006, Morales issued a decree that brought much of the country's energy sector under state control and since then Bolivia has received a flood of revenue that reached $1.7 billion in 2007 and is expected to reach $2.5 billion by end-2008, the president said. That wealth "does not belong to Evo Morales, or the government, or the prefects or the mayors, it belongs to all the Bolivian people," he said. The statement was designed to counter claims by regional leaders in the provinces of Santa Cruz and Tarija – where more than 85% of the country's hydrocarbon wealth is located – that they deserve a higher percentage of profits from the country's gas sales.

Bolivia has been shaken by political crisis in recent months. In the latest, Bolivians in Santa Cruz voted overwhelmingly in favor of a controversial autonomy statute, which seeks to distance the region from central government administration. The preliminary results showed that more than 80% of voters had approved the statute, which asked whether residents of the province wanted to appoint their own governors and police force, and set up a new tax system independent of La Paz. Other eastern Bolivian provinces have their own autonomy referendums planned for June.

Morales condemned the vote as illegal and said it wasn't binding. He also said the vote appeared to have had a poor turnout, and results may have been affected by violence and fraud. The referendum "has not had the success that some families and powerful groups hoped for in the province," Morales said in a televised address. He said that at least 40% of registered voters had abstained from casting ballots, and, as such, less than half of all Crucenos, as the province residents are known, had shown support for autonomy. Violence, which reportedly resulted in at least one death in the province as "Yes" supporters clashed with protesters, kept some away from the polls, according to state news agency ABI.

Turkey tests EU relations over Nabucco

Turkey faces an energy policy dilemma, according to participants at the Istanbul Forum 2008, held in May. It must decide whether to throw in its lot with the EU, or persist in its policy of extracting as much value as possible from its geographical position. The planned Nabucco gas pipeline is a test case: if it thinks it will never get into the EU, they said, Turkey may as well go for as much money as it can get.

Turkey's Nabucco partners – Austria's OMV, Bulgaria's Bulgargaz, Germany's RWE, Hungary's MOL and Romania's Romgaz – each with a sixth share, want Turkey to charge traditional transit fees for gas it transports from the Caspian and Middle East to Europe, but Turkey has different ideas. It has already, in the case of Edison bringing Caspian gas into Turkey for delivery to Greece and Italy, extracted the right to buy some 15% of the gas at the entry point, at cost.

Mehmet Ogutcu, a senior executive for British Gas International, said: "If Turkey is playing for the role of an energy hub, it should not use pipelines as tools to get what it wants. It's not perceived well in Europe." Ogutcu said the second half of this year will be crucial as the Energy Chapter of Turkey's EU membership negotiations opens under the oversight of France's presidency of the EU. French President Nicholas Sarkozy strongly opposes Turkey's membership of the EU, and Turkey has blocked France's participation in Nabucco.

Turkey is at odds with Europe on other energy issues. Ankara is open to the inclusion of Russian gas in Nabucco, which runs contrary to the EU's policy of diversifying energy supplies away from Russia. Turkey is also negotiating with Iran to pipe Iranian gas through Nabucco. And it has fallen out with Iraq, whose gas the EU wants for Nabucco. In addition, Turkey had a row with Egypt, another potential Nabucco supplier, during talks in Brussels over its energy hub ambitions.

The EU coordinator for the Nabucco gas pipeline project, Jozias van Aartsen, is to chair an intergovernmental conference in the Netherlands this summer. There is no date fixed yet for the conference, said the European Commission, but the plan is to invite representatives from Azerbaijan, Turkey, the Nabucco consortium and possibly others. The planned 30 Bcm a year pipeline is to carry gas from the Caspian region and Middle East across Turkey, Bulgaria, Romania, Hungary to the Baumgarten gas hub in Austria.

The Commission also reconfirmed its willingness to approve national energy regulators' exemptions from EU third-party-access rules in the four EU countries involved. The exemptions would allow the Nabucco partners to sign long-term capacity contracts. The Commission said it had already approved an exemption for Austria and that it was considering similar requests from Bulgaria, Hungary and Romania.

Italy overturns ban on nuclear power

Italy hopes to build nuclear power stations, according to the Economic Development Minister Claudio Scajola, in a move that overturns a 22-year-long rejection of atomic power established by referendum. Scajola said Italy will build third generation nuclear power plants at the Italian employers' federation Confindustria's annual meeting in Rome. "During the term of this parliament we will lay the first stone for the construction in our country of a group of new generation nuclear power stations," Scajola said.

Fulvio Conti CEO of Italian power major Enel, said, "technically speaking we are ready [to start nuclear power generation]. It's effectively the length of the legislation period, which lasts for five years, which could be a feasible road [to realize the nuclear option]."

He added that an "updated legislative picture" would be a strong supportive sign from the government. Conti underlined the "importance of diversifying the Italian energy mix" which is currently dominated by gas and coal-fired power generation. In April, Conti told the International Energy Forum in Rome that Italy – which generates around 60% of its energy from gas – was "too dependent" on gas imports.

"Both the head of Italian Confindustria Emma Marcegaglia and Italy's new prime minister Silvio Berlusconi have reiterated their position in favor of nuclear power generation," a ministry spokeswoman said. Berlusconi has restated his support for nuclear made during his election campaign. The decision to renounce nuclear power followed the nuclear disaster in Chernobyl, Ukraine on April 26, 1986.

European nuclear renaissance

Italy's decision to look again at nuclear comes as the industry is enjoying something of a renaissance across Europe. France, which already produces the vast majority of its electricity from nuclear, remains a supporter, and is building a new reactor model – the European Pressurized Water Reactor or EPR at Flamanville in Normandy.

The UK government is keen on new nuclear as a method to reduce dependency on imported gas and cut carbon dioxide emissions by displacing gas and coal-fired generation. Bids are currently being taken for British Energy, which owns the best sites for new nuclear build in the UK. EDF, the French state power company, is thought to be in the lead.

Finland is also building a new nuclear power reactor, which will be the first EPR, although it has suffered large cost over-runs and time delays, as well as technical difficulties. The 1,600 MW plant is being built at Olkiluoto by France's Areva and Germany's Siemens.

Germany for the moment is sticking to a plan to phase out all its existing nuclear power plants after they have run for a certain number of production hours, and then not to build any more. The largest party in the ruling coalition, the conservative Christian Democratic Union, however, is in favor of nuclear power.

Japan faces huge hike in energy import prices

Japan will experiencing a huge jump in energy prices this year as the price of imports rises steeply. Having few energy resources of its own, Japan is highly vulnerable to price changes in international markets. The country is the second largest importer of crude oil in the world and also depends on imported LNG for the bulk of its natural gas consumption, as well as importing coal.

Thermal sources account for about 60% of Japan's electricity generation. The reliance on thermal generation has been increased by the outage of the 8.2 Kashiwazaki-Kariwa nuclear facility since an earthquake in July 2007. Data released by Japan's Federation of Electric Power Companies showed that in May the Tokyo Electric Power Company, which operates Kashiwazaki-Kariwa, consumed 45.7% more crude and fuel oil in April this year, compared with the same month last year.

Owing to its energy import dependency and high domestic prices, Japan is also the world's most efficient user of energy, measured in terms of primary energy consumption per unit of GDP. Rising import prices suggest a further squeeze on industry, which will have to maintain mometum behind its energy efficiency drive.

Crude rose to new records over $130/barrel in May, but Japan is also facing large price rises for both coal and LNG imports. According to industry sources, China Coal has settled its fiscal 2008 thermal contract prices in Japan at $131.40/mt FOB, a 93.52% increase from the price in fiscal year 2007 of $67.90/mt. The tonnage involved is 4.6 million mt, up from 4.3 million mt in 2007. The price is thought to apply to coal from Shandong province, and negotiations are ongoing for the Yanzhou coal brand. Sellers are believed to be asking for more than $170/mt FOB for Yanzhou coal, an offer that Japanese buyers have rejected. Yanzhou was priced at around $74/mt FOB in Japan in 2007.

LNG reviews

Talks between LNG buyers in Japan and suppliers from Qatar, Abu Dhabi and Australia's North West Shelf over the renegotiation of term contract price formulas are making little headway. Taking a cue from recent LNG deals, in which China is understood to have agreed to pay oil parity prices for long-term contracts, the three sellers are pushing to reset the price formulas of existing contracts. They are demanding 16-17% of the crude price for each MMBtu of LNG.

Japanese buyers are resisting, arguing that the contracts under review are for existing deals, not new ones or renewals. The highest term price that Japan has agreed to so far is believed to be at "a little below oil parity" for renewing a bundle of contracts with Indonesia expiring in 2010. Platts reported in late March that a senior Indonesian government official had said the renewal price for the six-member Japanese buyer consortium's contract would shoot up to almost $16/MMBtu at $100/barrel oil.

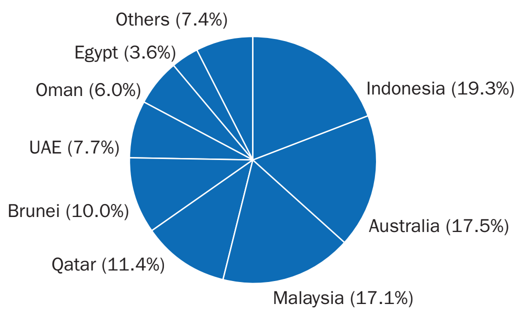
"If Japan accepts an oil parity price for term LNG [from these three suppliers], this will have an influence on contracts with other producers," said a trading source. "It might be acceptable if oil is around $80-90/b, but with oil going up to $120/b, a 16-17% link means LNG prices of around $20/MMBtu, which is very difficult for Japanese buyers." Japan paid an average of $11.02/MMBtu for LNG in March, when the Japan Customs Cleared crude import price was $95.10/b.

The financial impact for Japanese buyers is far reaching because for some of the contracts the price review will be retroactive to end 2003-2004. "There is a lot of money at stake," the second source said. Some Japanese buyers have set up provisions for the additional payments they would have to make after the new term prices are concluded, but the amounts put aside are likely to be well under oil parity levels, the source said. While the legal implications of a fallout are hazy, "there has got to be an agreement eventually ... the sellers couldn't just stop supplying and the buyers couldn't stop buying either," he added.

Some of the contracts being reviewed date back as far as 1989. The renegotiation of term prices is either provided for in the original agreements, or arose as a result of oil prices climbing beyond the defined ranges in the LNG price formula, sources said. In some of the contracts, a letter is attached in which both sides agreed that the initial price formula would apply for a term such as ten years, after which price reviews would take place every three or five years. Price reviews can also be triggered when the oil market falls way outside the ranges defined in the original contract.

In most past LNG term contracts, a "middle range" oil price of around $15-25/b has been adopted in the oil-linked price formula. When oil is in a lower or higher band, the LNG-oil relationship is weakened considerably, so as to reduce the negative impact of extremely low oil prices on sellers, and extremely high oil prices on buyers. In such contracts, the LNG price typically remains defined for oil down to around $11/b and up to about $29/b. When oil is outside the defined bands, the usual practice has been to temporarily apply the high or low-band formula until oil prices returned to the specified ranges. Crude has not traded at $29/b since 2003 and looks obsolete with current prices over $130/b.

Origin of Japanese LNG imports % (Mar 2008)



Source: Japanese Ministry of Finance

Chinese and Middle Eastern investors eye Nigeria's coal assets

Nigeria's dormant coal industry is attracting fresh interest from Chinese and Middle Eastern investors,who are considering building new coal-fired plants to feed the country's growing energy demand. Dubai World, an investment fund belonging to the government of Dubai, part of the United Arab Emirates, is one such investor.

Dubai World chairman Sultan Ahmed Bin Sulayem met the president of Nigeria, Umaru Yar'Adua, in Abuja in April. A statement from Dubai World quoted Sulayem as saying that the company intended to invest $1.5 billion in Nigeria over the next few years in energy, port development and petchems. One project is a proposal to build a coal-fired power plant at Enugu. "Nigeria has one of the best quality coal desposits in the world with the lowest sulfur content," Dubai World said.

Nigeria has also recently received a delegation of officials from China's Development Bank, according to local press reports. The Chinese officials met Nigeria's mines minister Sarafa Tunji Ishola and discussed the prospects for power generation from Nigeria's coal assets. The minister was quoted as saying any potential Chinese investment should give priority to coal because it was his government's "number one priority to address our power challenges". Two Chinese companies, Western Goldfield and Sinocoal, are already present in Nigeria and are involved in power projects.

Nigerian coal record

Nigeria's record on coal has to date been poor, despite having large good quality resources, estimated at 2.7 billion tons of reserves. Nigeria's coal is found in the Cretaceous Arabmra Basin, which stretches in a huge band across the south east of the country. The seams are more than a meter thick and much of the coal is high quality with a calorific value of between 5,000 to 6,000 cal/kg with low ash and sulfur.

Nigeria's coal industry was founded with a drift mine in 1909 and production peaked at 900,000 t/yr in 1959. But the decay of infrastructure and the rise of oil saw coal production dwindle to almost nothing as the industry was ignored and oil and gas exports were prioritized over domestic development. A major constraint on reviving the industry is the decay of the country's railways and rolling stock. To address the problems the sector faces, the government proposes to privatize the Nigerian Coal Corp, the state-owned company that holds Nigeria's coal assets.

Coal to power

The government is keen to tie coal mining investment in with power plant development to address the country's woeful lack of effective generating capacity. But again the record here is poor. Former Nigerian president Olusegun Obasanjo was reported to have told parliament that his administration spent $6.5 billion on the country's power generation sector but that there was little to show for the spending.

Obasanjo said when he came to office in 1999, Nigeria had seven power stations in different stages of disrepair and obsolescence and generating about 1,500 MW. An additional six power stations were built by 2007 namely, Afam II, Geregu, Ikot Abasi-Ibom, Okpai, Omotosho, Palalanto, amounting to a total installed capacity of 2,000 MW.

India's NTPC looks to overseas coal assets and sustainability

India's state-owned National Thermal Power Corporation, the country's largest generating company, has outlined a new strategy aimed at securing international coal assets, investing in clean coal technology and sustainable energy. The company wants to expand its supply chain to meet its rising coal requirements by buying equity stakes in coal mines in Indonesia, Mozambique and South Africa.

"One to two mines have been identified in Indonesia" and three merchant bankers have been appointed to help buy into the mining assets, according to newly appointed NTPC chairman R.S. Sharma. He said efforts are being made to finalize the purchase by year's end. The company wants a controlling interest so as to determine production and the price of coal, he said.

NTPC sources its coal domestically with imports totaling only 2.5 million mt in the year to March 2008. However, to meet strict environmental laws, India's domestic high-ash coal must be mixed with imported low-ash coal. This has seen NTPC plan for imports of 5 million mt this year. NTPC aims to source about 20 million mt/year from overseas mining assets with 25% already accounted for by current projects, Sharma said.

The move to acquire overseas assets is independent of the Coal Ventures International joint venture, with four other public enterprises, including Coal India Ltd. and three steel companies, an NTPC official said. This JV was announced by the government in 2007 and targets some 500 million mt in overseas reserves by 2020.

NTPC is also creating a dedicated fund for greener energy and will put side 0.5% of its net profit to fund R&D in sustainable energy. One of the objectives of the fund, which is expected to amount to Rupee 300 million/year ($7.5 million), is the development of coal gasification technology, while improving plant efficiency. The funding project has been dictated by Dr. Rajendra Kumar Pachauri, chairman of the Inter-Governmental Panel on Climate Change. The first task is to complete an audit on NTPC greenhouse gas emissions.

With 29,144 MW of installed capacity, over 80% coal-fired, and another 16,930 MW under construction about 90% of which is coal-fired, the NTPC is aiming to generate 50,000 MW by 2012 and 75,000 MW by 2017. The company has estimated its coal consumption will rise to 200 million mt in 2012 and 280 million mt in 2017 from over 130 million mt in 2008.

RusHydro scales back investment plans

Russia's state hydropower producer RusHydro has dropped plans to start construction of a number of key projects this year and expects delays in the launch of others, mainly due to rising construction costs, according to deputy chairman Vasily Zubakin. In total, over the next three years, the company plans to commission around 2 GW less capacity than previously planned. "This is a significant consequence for our investment program, but in current conditions, at current prices, these projects are not yet commercial," Zubakin said.

Last November, RusHydro unveiled its new investment program, which foresaw the commissioning of 22.2 GW of new capacity by 2020, at a total cost of Rb 1,600 billion ($65 billion). Under the new plan, approved May 19, the launch of the first stage of the 3 GW Boguchanskaya hydropower project has been pushed back one year to 2010. The plant is being developed with RusAl in eastern Siberia. The first stage of the 840 MW Zagorskaya pumped storage project in the Moscow region has also been put back a year to 2011.

Commissioning the first unit of the Zaramagskiye project has been deferred from 2010 until 2011, as has the 100 MW Gotsatlinskaya project, while the 140 MW Zelenchuk cascade has been delayed until after 2010. The 90 MW Verkhnekrasnogorsk project has been dropped completely. In addition, the company does not plan to start construction this year of the 324 MW Nizhnebureyskaya and Nizhnezeiskiye hydropower plants, as well as the cascade of Zelenchuk plants.

The company also approved its revised investments for 2008, which foresees Rb 78.1 billion in investments and the launch of 410 MW of additional capacity. Of the total, Rb 10.4 billion is to be spent in upgrading existing capacity, Rb 53.9 billion for plants under construction and Rb 6 billion on planned projects. RusHydro will fund Rb 26.8 billion of the year's capex, while UES, the current majority shareholder of RusHydro, is to provide Rb 30.2 billion. The remainder will be raised from an additional share issue, loans and investors' funds.

RusHydro expects the government to adopt legislation this year making renewable energy generation in Russia more profitable. Backing up last year's amendments to Russia's electricity law, the government is expected to approve subsidy measures for connections to grids and priority purchase of renewable energy. In addition, Moscow is likely to set a target for renewables' share of total generation capacity. RusHydro expects this to be 1.5% of total generation by 2010, rising to 4% by 2020. This will include geothermal, wind, tidal and small hydro power generation, but exclude large hydropower plants, Zubakin said

Under RusHydro's investment plans for 2008-2012, the company plans to spend Rb 56.7 billion ($2.38 billion), or 9% of its total spending, on renewable energy. The company is designing a new 2.5 MW binary cycle geothermal power plant, due to be commissioned over the next two years. "The binary cycle will let us build geothermal power plants not only in volcanic regions, but in a variety of other regions," Zubakin said.

Zubakin also confirmed plans to further develop wind power generation, but under its revised investment program, plans overall to reduce commissioning of wind power projects by 16 MW in 2008-2010. RusHydro will also reduce the capacity of new small hydropower plants to be developed by 185 MW. Last but not least, the company now expects to commission the Severnaya tidal power plant in 2011, but its capacity will be expanded from 2 MW to 12 MW when fully constructed.

Slovakia looks at investor options for new nuclear plant

The Slovak state should take a leading role in building a new nuclear plant, but bring in a strategic investor either from the start or once construction is completed to put the project on a sounder financial and commercial footing, according to two scenarios presented by the Ministry of Economy in mid-May. A third scenario of putting the whole project in private hands was given short shrift in the report. The government expects to make a decision on whether and under what conditions to launch construction by December.

The analysis laid bare the fact that the state nuclear company JAVYS does not have the estimated SKr 100 billion ($4.7 billion) needed to construct a nuclear plant with installed capacity of up to 1,750 MW and would probably have to seek loans to cover around 80% of the cost. Up to SKr 30 billion could, for example, be sought from main suppliers, and the financial markets tapped for a further SKr 50 billion, the report said.

Even if the project is 100% in public hands at the start, allowing the state to determine the project's parameters and provide a maximum number of contracts for local firms, the door could be left open for a strategic investor at a later date. A 49% stake in the finished power plant could be sold, for example by public tender, the report said.

The other option of bringing in a strategic investor from the start, with a maximum 49% stake, would probably help smooth financing at the start of the project and help sell electricity when it is completed. One downside would be that this would give less room for the state to influence the allocation of contracts.

The government has set out a series of deadlines for further work on the project. The basis for a feasibility study and an environmnetal impact assessment should be completed by end-October. A further analysis of plant construction and selection of a strategic investor should be ready for a government decision in November, allowing a final decision on the project in December.

Owing to the closure of an existing nuclear plant, Slovakia is expected become a net power importer from the start of 2009, with dependence on imports reaching 20% of its overall supply needs.

India proposes local content criteria for power tenders

The Indian government has proposed that the domestic manufacture of equipment should become a precondition for bidder participation in future power tenders. "In future, domestic manufacturing will be the yardstick for all foreign equipment suppliers. The policy directive will apply to all new projects, barring those for which orders have already been placed. We will soon get the prime minister's orders on this policy," said Minister of State for Power Jairam Ramesh.

It is not yet clear if the policy will apply to private sector projects, as well as to tenders by state and central government-owned companies. Ramesh is a junior minister and only joined the power ministry on April 6. The senior minister with cabinet rank is Sushilkukar Shinde. But political analysts believe that Shinde will be moved by the leadership of the Congress party, which heads the United Progressive Alliance coalition government, to Maharashtra state to take over as chief minister. Ramesh, who has already served as a junior minister in the commerce ministry, is regarded as having moved to the power ministry to familiarize himself with sector developments before he replaces Shinde.

Shinde has pinned much of the blame for the persistent failure to meet national power generation targets on the leading domestic power equipment manufacturer Bharat Heavy Electricals Ltd. Shinde has insisted that the equipment purchases for all government-sponsored projects should be tendered through international competitive bidding processes.

The switch in policy could have considerable repercussions. Central government-owned power undertakings alone are scheduled to build more than half of the 78,577 MW of new grid-connected generation capacity targeted during the five-year development plan period to March 2012. Ramesh's statement implies that there would be near monopoly protection for Bhel, which is currently the only domestic manufacturer of large-scale turbines and boilers. The state-owned company is ramping up its annual manufacturing capacity to 15,000 MW by end-2009 from 10,000 MW at present.

Another local company is also increasing its manufacturing capability, in its case to 4,000 MW per year. Larsen & Toubro is the only Indian private sector company to have entered the supercritical boiler and steam turbine generator production business. The company will manufacture and market the products through two separate joint ventures with Japan's Mitsubishi Heavy Industries. The Mumbai-based L&T will own a 51% stake in each of the joint ventures, which will manufacture supercritical equipment for power plants ranging in size from 500 to 1,000 MW.

France's Alstom is the only other company engaged in large-scale power equipment manufacture in India. However, Alstom Projects India at present only produces boiler and hydroelectric power equipment.

Chinese manufacturers have been actively bidding for Indian projects. Analysts believe that it is the threat from these companies to Bhel which has led to the proposed change in policy. They say that the cost competitiveness of Chinese equipment producers, based on cheap labor and other costs together with economies of scale, plus shorter delivery schedules, has tipped the balance in their favor in bidding for large Indian power projects.

In total, more than 15 utilities are reported to have awarded equipment contracts to Chinese suppliers. Bhel chairman and managing director, K. Ravi Kumar, estimates that aggregate orders totaling 22,000 MW have been awarded to Chinese companies.

China targets rise in heavy equipment manufacture

Chinese heavy equipment fabricating companies have set ambitious targets to produce 20 or more sets of power reactor pressure vessels and steam generators per year by about the middle of the next decade, according to company officials. Executives from European and US companies who have been working with Chinese firms on equipment manufacture suggested that that production rate target may not be achievable until later than the mid-2010s.

Financial analysts in Hong Kong said that their expectations for nuclear power construction in China would support the investment necessary to get Chinese firms to make 20 sets per year, provided high input costs for nuclear investments in China don't slow the program down. Estimates by foreign industry experts about Chinese nuclear heavy equipment manufacturing capacity vary. According to some, China right now may comfortably be able to produce about three sets of equipment per year. Others suggest that sometime in the next two years China' may be capable of producing as many as six sets per year.

They also said it was less certain how fast China would move on to produce ultra-large forgings for this equipment, due to the investment necessary and quality assurance certification issues. Chinese fabricators are now making investments to make these big forgings in coming years, but for now the largest forgings for Chinese nuclear plants are imported.

Japan Steel Works, currently the world's main supplier of ultra-large forgings for nuclear power plants, defines the category as ingots weighing between 350 mt and 600 mt. At least two Chinese companies can currently make forgings at the lower end of this range, Chinese executives said. One company can pour ingots as large as 500 mt, they said.

Since the late 1990s, China First Heavy Industries, China National Erzhong Co., and Shanghai Electric Heavy Industries Corp., have been designated as centers of nuclear heavy equipment manufacturing. Also, in partnership with French industry, the Sichuan-based Dongfang group of companies has developed capabilities for manufacturing vessels and steam generators.

China turns to solar power to hit renewables targets

Solar power is beginning to get more attention in China. According to Liao Cuiping, an associate professor at the Energy Strategy Research Center in Guangzhou, government support is shifting away from biomass-fired plants, and towards solar technologies. “The government strongly believes in this technology and is carrying out feasibility studies,” says Liao. “In more deserted areas of the country they have very rich solar resources, so this technology makes sense. It’s hoping for large scale utilization by 2030, and it could replace lots of electricity capacity that’s currently fired by coal.”

As in other countries, the growth in the renewables industry in China has been spurred by subsidies and targets rather than by market forces. The government has set a target of 8 GW of installed wind capacity by 2010, rising to 30 GW by 2020. Chinese industry representatives say growth is such that capacity could exceed those targets by as much as 100%.

Moreover, China’s National Climate Change Program, published in June 2007 by the National Development and Reform Commission, put forward a new target of sourcing 10% of primary energy supplies from renewables by 2010. The bulk of this will be met by large-scale hydro power. China had 125 GW of installed hydro capacity in 2006. But even when all other sources are accounted for, the proportion of energy supplied by renewables in 2006 only reached 7% of total primary energy supply. And with only a limited number of sites suitable for new hydro plant, the rest of the shortfall will involve drawing on smaller scale technologies.

Alongside the targets and aspirations, the NDRC has also created premium tariffs for some renewable energy projects, while grid operators must purchase all electricity produced from such schemes, providing the tariffs are “economic and reasonable.” So there is plenty of financial incentive for industry to move into renewables. All this means that the drive for wind, solar and biomass is steadily growing.

Wind is well established and biomass projects are also growing in stature, with several 50 MW plants already in operation and more on the way. One company alone, China Power, aims to have 3.2 GW of installed biomass and hydropower plant by 2013.

However, biomass is suffering from its association with rising food prices, Liao says. Only four companies are licensed to produce bioethanol, she notes, with a total production of 1.02 million tons per year. “But the government is not giving out any other new licenses, because of concerns over rising food prices.” Biomass research has shifted to straw, rice husk and wood pellets, she says.

Although power generation tends to use non-food feedstock, with grain used instead to generate transportation fuels, the cut back on biofuels means renewables targets for total energy consumption are looking that much harder to achieve. This has led to an increased focus on solar, which is attracting more attention as the breadth of technologies available increases. “There is more R&D work being done on solar energy … particularly looking at solar thermal plants, including the solar tower approach,” Liao explains. Two solar tower plants, each with a capacity of about 50 MW, are already planned, she adds, one at Hangzhou, near Shanghai, and another at Yanqing, near Beijing.

Solar tower plants use the sun’s energy to heat air under a large canopy, which is then funneled up through a tower containing turbines, generating power. The technology is not new, but has gained new life in recent years as concerns about the environment have come to the fore and fossil fuels have risen in price. Australian company EnviroMission, which holds the exclusive license for the technology in Australia, says it has signed a contract with a Chinese company to work on developing the technology in China.

Liao notes that in addition to solar towers, government researchers are looking at the more traditional, smaller capacity end of generation. “We’re working with the construction industry at the moment, looking at ‘smart glass’ for windows, incorporating photovoltaics.” That chimes with the National Climate Change Program, which states a government aim of popularizing family-use photovoltaic power systems or small-scale photovoltaic power plants in remote areas.

PV is also being used for larger projects. The Nantong Qiangsheng Photovoltaic Technology Company said in March that it had signed an agreement with the Rudong Economy and Technology Development Zone in Nantong for a 1 MW PV project costing Yuan 28 million ($3.9 million). However, the cost for electricity from that plant, at Yuan 3/kWh, is notably above the cost of electricity generated from fossil fuels.

Some money can be made back through the government’s premium tariffs for renewable projects. And such projects can also gain credits generated under the Kyoto Protocol’s clean development mechanism. But Liao says that although CDM awareness is “widespread,” it is not very effective at encouraging local renewable projects. “The problem is that the process is very complicated, with all the various documents required. There is a move to do ‘packed CDMs,’ whereby smaller scale projects group together in larger units, where it might be difficult for individual projects to get CERs. But as yet none have received CERs.”

Liao says that the more immediately available support comes from local government, particularly under targets to cut “energy use,” towards which electricity produced from renewables can count. The government has set a national target of cutting energy use by 20% by 2010, and local municipalities are supposed to carry this out. They have set specific targets for companies, so there is some encouragement for them to use smaller-scale renewables such as solar water heaters.

As with other areas, the government has set targets for solar. One academic source said the government is looking at 30 GW by 2050. That may seem small in comparison with wind, but it represents a huge jump from current levels. And just as wind has outperformed expectations, solar too may yet surprise.

Airbus joins 'bio-jet fuel' team

European aircraft maker Airbus has teamed up with several companies to develop a biofuel that could meet a third of all commercial aviation fuel demand by 2030 without affecting food resources, the company has announced. Working with Honeywell Aerospace, UOP (a Honeywell Company), International Aero Engines and JetBlue Airways, the group plans to convert vegetation and algae-based oils into jet fuel for use in commercial aircraft. Non-food crop biomass fuels provide a better fuel-to-emissions lifecycle than kerosene currently does, Airbus said in a statement.

"Millions of barrels of kerosene are used each day for aircraft fuel and worldwide demand is growing. In order to replace a significant portion of that jet fuel with bio-jet, we need to find something that has much greater yield than the current biomass sources available," said Sebastien Remy, head of alternative fuels research programs for Airbus. This "second-generation bio-jet fuel" will be produced using technology developed by UOP that converts biological material into renewable jet fuel that performs identically to traditional fuels, while meeting the stringent performance specifications for flight, the company said.

The potential environmental advantages of using second-generation bio-jet are extensive, including reduced emissions and particulates, reduced carbon footprint, improved engine cleanliness, reduced contrail formation and lifecycle benefits, Airbus said. But there is also an economic imperative – jet fuel is the biggest expense most airlines incur. With fuel prices at record highs, finding alternative fuels is one way to manage the pressure. Biodiesel has been used mainly in ground transportation to date. But with winterization processing, it can be blended safely with jet fuel for use in commercial and military planes, according to the US Department of Agriculture.

The first flight by a commercial airline to be partly powered by biofuels took place in February. A Virgin Atlantic Boeing 747 jumbo jet flew from London to Amsterdam, carrying biofuels mixed with traditional kerosene, but no passengers. The plane was fuelled by a biofuel blend of babassu oil – extracted from the nuts of the babassu tree – and coconut oil. Both products are more commonly found in cosmetics like lip balm and shaving cream. Virgin Atlantic chief Richard Branson hailed the demonstration flight as a breakthrough for the airline industry and proof that there were viable alternatives to traditional jet fuel.

By contrast, environmentalists say that in addition to concerns over rising food prices biofuels are a poor alternative to conventional fossil fuels. Clearing raw land to produce biofuels can contribute to global warming by emitting large amounts of greenhouse gases, they argue, a practice that has been condemned in Indonesia, where peat bogs have been cleared for palm oil production. According to a recent edition of the journal Science, carbon dioxide emissions from new croplands carved into rainforests, savannas, wetlands or grasslands will easily surpass the overall amount of CO_2 emissions reduced through the use of biofuels.

Scientists promote sweet sorghum as biofuel crop

The sweet sorghum plant could be the miracle crop that provides cheap animal feed and fuel without straining the world's food supply or harming the environment, according to scientists working on a pilot project in India. "We consider sweet sorghum an ideal 'smart crop' because it produces food as well as fuel," said William Dar, director general of the non-profit International Crops Research Institute for the Semi-Arid Tropics.

Sweet sorghum is the world's fifth-largest grain crop after rice, corn, wheat and barley. It grows in dry conditions, tolerates heat, salt and waterlogging, making it an ideal crop for semi-arid areas where many of the world's poor live, ICRISAT agronomist Mark Winslow said. The plant grows to a height of 8-12 feet and looks like corn. Its stalks are crushed yielding sweet juice that is fermented and distilled to obtain bioethanol, a clean burning fuel with a high octane rating.

It has high positive energy balance, producing about eight units of energy for every unit of energy invested in its cultivation and production, roughly equivalent to sugarcane and about four times that of corn. It also requires little or no irrigation, limiting the use of fuel-burning water pumps that emit carbon dioxide.

"With proper management, smallholder farmers can improve their incomes by 20% compared with alternative crops in dry areas in India," said Dar. In partnership with Rusni Distilleries and some 791 farmers in Andhra Pradesh, ICRISAT helped build and operate a commercial bioethanol plant, which began operation in 2007.

Sweet sorghum in India costs $1.74 to produce a gallon of ethanol, compared with $2.19 for sugarcane and $2.12 for corn, the institute said. Similar partnership projects are underway in the Philippines, Mexico, Mozambique and Kenya as countries search for alternative fuels, India-based ICRISAT added. A project funded by the UN Food and Agriculture Organization is also underway in the north of China. In the US, the Department of Agriculture is sponsoring an international conference in Houston in August to examine the plant's potential in ethanol production.

In addition to ethanol, "I think (sorghum) is going to be one of the two big crops in the tropics" that supply biofuel such as ethanol, the demand for which "far exceeds the supply" on the world market, Winslow said. He added that India could meet its entire fuel needs with 100 bioethanol plants like the Andhra Pradesh one, which produces 10,568 gallons of ethanol a day. Sweet sorghum is grown on more than 107 million acres in 99 countries, with the US, Nigeria, India, China, Mexico, Sudan and Argentina the main producers.

CO2 Market

EU carbon price hits two-year high

EU emission Allowance prices hit a two-year high of €26.55 per metric ton of carbon dioxide equivalent on May 22. The gains were driven by strong natural gas prices, which at the UK National Balancing Point rallied in May to their highest levels for over a year. Higher gas prices prompt power generators with fuel flexibility to switch to coal. Coal's high emissions intensity boosts demand for EUAs to cover the additional emissions. Gas prices were in turn responding to the rally in crude oil prices, which hit new records in May, so that carbon prices were in effect dragged up by the oil market.

EUA prices for December 2008 delivery eased from a high on April 22 to trade at around €23.50-24.00 on May 1, a three-week low, as weakening energy prices dragged carbon lower. However, values rebounded May 2, as crude jumped around $3/barrel. Carbon continued to follow crude's lead during the first half of May. Bullish crude markets helped EUAs test resistance at €25.50/mt, and the December 2008 EUA contract on the European Climate Exchange reached an intraday high of €25.80 on May 12, its highest level for 12 months.

However, prices failed to hold at this level, and by May 14, December 2008 EUAs closed at €24.46/mt on the ECX, and around €24.43/mt on the over-the-counter market. But for the next six trading days, EUA prices resumed their upward trend, setting a two-year high of €26.55/mt on May 22, as Brent crude oil futures hit $135/bbl for the first time. "The relationship between oil and carbon is tenuous at the best of times. It's just panic – it's a thin market," said one London-based trader on May 22. December 2008 EUAs had opened at around €26.40 on the ECX, up almost €0.70 on the previous close. That triggered automatic buy orders that pushed the price higher still, he said.

The trader argued that strong coal prices ought to put a cap on carbon prices, but bullish sentiment in the oil markets had pushed carbon into new territory. "The whole energy complex is higher. You've got to look at coal and power," the trader said. German calendar 2009 power hit an all-time high of €74/MWh on May 22, driven by higher oil and coal prices.

The price of EUAs for 2008 delivery has only briefly stood above €30/mt, in late April 2006. That was during the Phase 1 test period of the EU ETS, before the market recognized the over-allocation of allowances by the European Commission in the 2005-2007 period.

CERs show less volatility

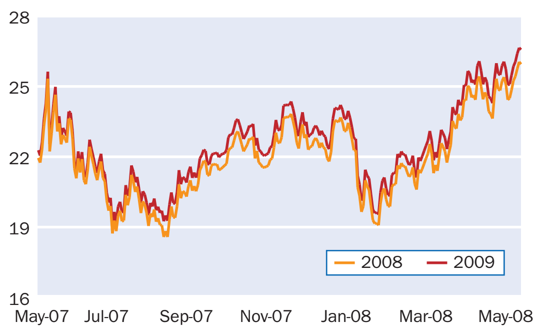
Certified Emission Reductions largely followed movements on EUAs during May, but showed much less volatility. CERs for December 2008 delivery drifted slightly from €16.40 on April 14, to €16.05 on May 1, showing some resilience to the sharper downward move on EUAs. CERs then jumped to €16.80-16.85 on May 6, spurred by a two-day rally in EUAs, with December 2008 EUAs hitting €25.325 on May 6.

The CERs were given a boost from a report released May 5 by the United Nations Environment Program's Risø Centre in Denmark, which dramatically reduced its projection of the volume of CERs that will be available between 2008 and 2012. The Risø Centre cut its CER supply forecast from 1.8 billion to 1.5 billion CERs in total over the period 2008-2012, following information released by third-party verifiers, which showed that around 18% of planned Clean Development Mechanism projects were unlikely to survive the regulatory process and therefore would be unable to generate credits.

Under the rules of the EU ETS in Phase 2, installations are allowed to import project-based credits such as CERs to comply with up to 10% of their annual emissions cap. Since CERs trade at a significant discount to EUAs, this import facility represents an attractive proposition for EU ETS compliance companies. The 10% limit means over the period 2008-2012, a total of 1.4 billion CERs could be bought up and submitted by EU ETS companies.

But EU ETS players compete for CERs with the industrialized country governments which accepted national emissions caps under the Kyoto Protocol. Since many of these governments have already signed forward purchase agreements for CERs, the amount available for EU ETS buyers may now be significantly lower than the 1.4 billion import level, representing a strong bullish element for forward delivery CER prices. By May 22, December 2008 CERs had climbed to a four-month high of €17.35/mt.

CO_2 price trend (€/mt)



Source: Platts Emissions Daily

Platts CO_2 assessment monthly averages – May 1-28, 2008 (€/mt)

Delivery	High – Low	Midpoint
Dec-08	25.180 – 25.130	25.150
Dec-09	25.810 – 25.770	25.790
Dec-10	26.530 – 26.480	26.510

All prices are in euros per metric tonne of carbon dioxide equivalent as traded under the EU Emissions Trading Scheme.

Source: Platts Emissions Daily

Data & Markets

Prices and supply on the up

The July contract for ICE Brent crude oil futures hit an all-time high of $135.14/barrel on May 22, moving ahead of NYMEX crude futures for the first time since February. The NYMEX contract also recorded a new high of $135.09/b. Crude prices saw volatile price swings of up to $5/barrel in intraday trade, but stabilized above $130/b, suggesting new highs could be tested, despite significant changes in the physical market.

The rally in crude followed a drop in OPEC-13 supply in April of 350,000 b/d to 31.87 million b/d, owing predominantly to disruptions to Nigerian production. A unilateral promise from Saudi Arabia to increase output by 300,000 b/d in mid-May had little impact; Saudi Arabia has for some time said it will supply whatever lifters ask for. Otherwise, OPEC sees little cause for action and has said it will not bring forward its next scheduled meeting from September 9.

Despite the record prices, there is growing evidence of over supply in the crude market, namely a build up of on-ship storage, particularly in Iran, and a swing over May in the structure of forward prices to contango. Having prices for forward delivery higher than for prompt indicates that the market is struggling to clear physical cargoes of crude in the short term.

Tight balances for product in the US and distillates globally have been the underlying factor supporting prices across the complex. The June contract for heating oil on NYMEX moved above the $4/gal level for the first time in May. Shortages in the distillate market saw the difference between ICE gasoil prices and crude reach record levels. The front-month August fuel oil contract on the Shanghai Futures Exchange closed at a new high of Yuan 4,926/mt ($708.7/mt) on May 26.

Gasoline typically sets the pace at this time of year as the US driving season kicks in, but with demand growth down year-on-year in the US and inventories at a comfortable level, the gasoline contract has lagged. As a result, European refining margins for gasoline are nearly flat, as weak demand in the US has reduced interest in European exports. The gasoline physical crack bid/offer range relative to ICE July Brent futures was valued at $0.15/$0.75/barrel on May 22, a decline of over $2/b over the week and more than $20/b year-on-year.

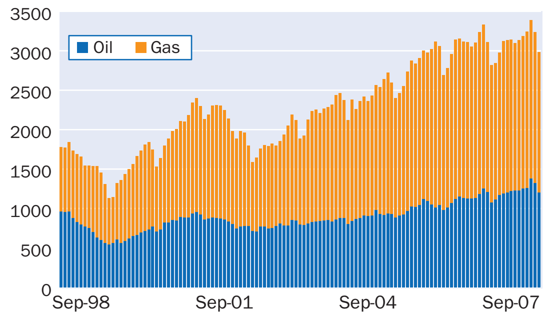
European refineries have little choice but to keep on producing large volumes of gasoline in order to maintain their profitable middle distillate output. But the trends in short-term crude supply, market structure and US gasoline consumption indicate that high prices are taking their toll on demand.

Oil forecasts (million b/d)

	Call on OPEC	Rise in non-OPEC supply	World oil demand	Rise in demand
May 2008 data for 2007				
EIA	30.9	0.4	85.4	0.8
IAE	31.3	0.6	85.8	1.1
OPEC	32.0	0.5	85.8	1.2
May 2008 Forecasts for 2008				
EIA	32.0	0.6	86.6	1.2
IAE	31.3	0.7	86.8	1.0
OPEC	31.8	0.8	86.9	1.1

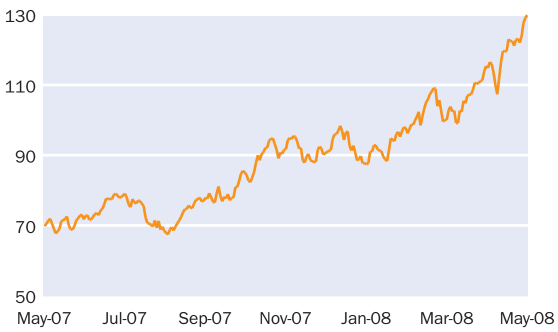
Sources: EIA, IAE, OPEC

International rig count (monthly average)



Source: Baker Hughes

Dated Brent ($/b)



2-year average to date: **76.29**
5-year average to date: **57.55** 10-year average to date: **40.22**

Source: Platts Global Alert

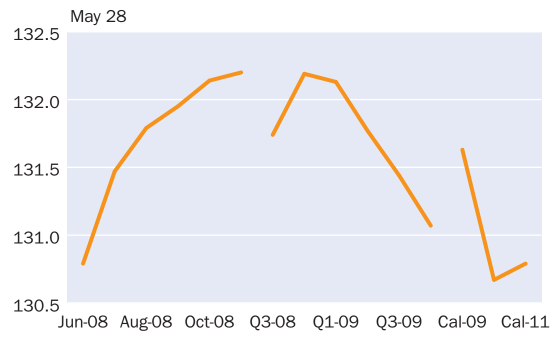
NYMEX 3-2-1 Crackspread* ($/b)

1-year average to date: **12.10**
2-year average to date: **12.52** 3-year average to date: **12.39**

* A hypothectical refining margin used for trading purposes based on three barrels of crude making two barrels of gasoline and one barrel of distillate.

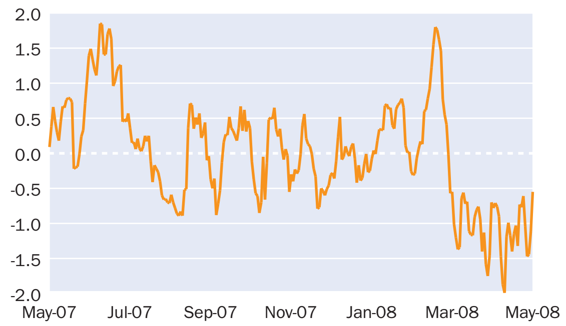
Source: Platts Global Alert

Platts forward curve for Dated Brent ($/b)



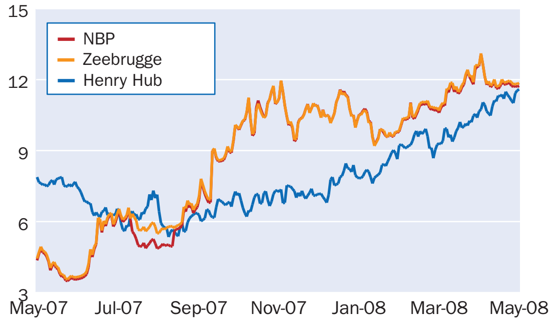
Source: Platts Forward Curve – Oil

Market structure: Dtd Brent vs 1st Mo ($/b)



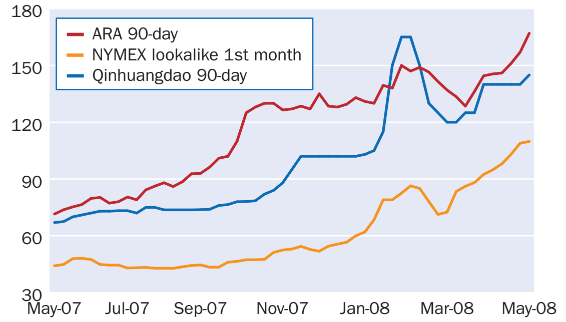
Source: Platts Global Alert

Natural Gas month-ahead ($/MMBtu)



Source: Platts Gas Daily, European Gas Daily

Coal ($/mt)

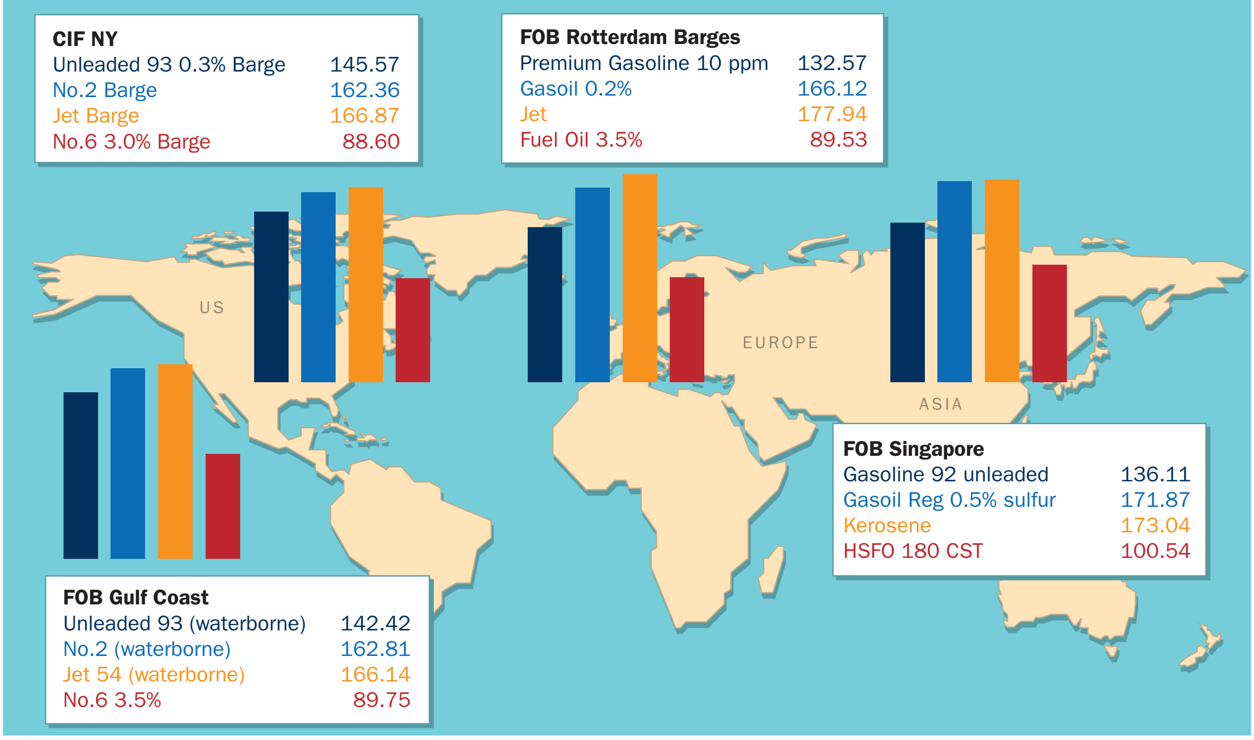


Based on energy values of CIF ARA 6,000 Kcal/kg,
FOB Qinhuangdao 6,200 Kcal/kg, Nymex lookalike 6,668 Kcal/kg

Source: Platts Coal Trader, Coal Trader International

Oil product comparisons ($/b) May 23, 2008

WTI front month: 131.54 **Brent front month: 130.43** **Dubai front month: 126.21**



CIF NY	
Unleaded 93 0.3% Barge	145.57
No.2 Barge	162.36
Jet Barge	166.87
No.6 3.0% Barge	88.60

FOB Rotterdam Barges	
Premium Gasoline 10 ppm	132.57
Gasoil 0.2%	166.12
Jet	177.94
Fuel Oil 3.5%	89.53

FOB Singapore	
Gasoline 92 unleaded	136.11
Gasoil Reg 0.5% sulfur	171.87
Kerosene	173.04
HSFO 180 CST	100.54

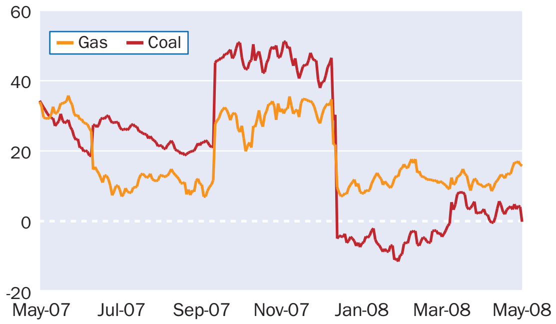
FOB Gulf Coast	
Unleaded 93 (waterborne)	142.42
No.2 (waterborne)	162.81
Jet 54 (waterborne)	166.14
No.6 3.5%	89.75

Source: Platts Global Alert

NWE next month generating cost comparisons, profit/loss ($/MWh)

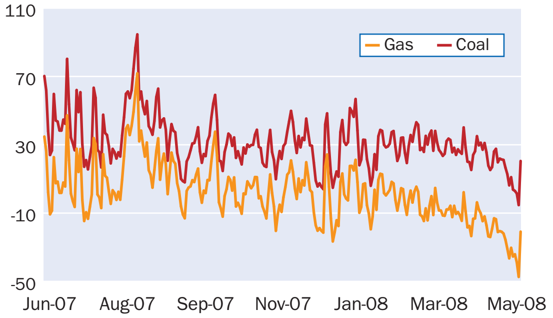
Source: Platts Emissions Daily

NWE next quarter generating cost comparisons, profit/loss ($/MWh)



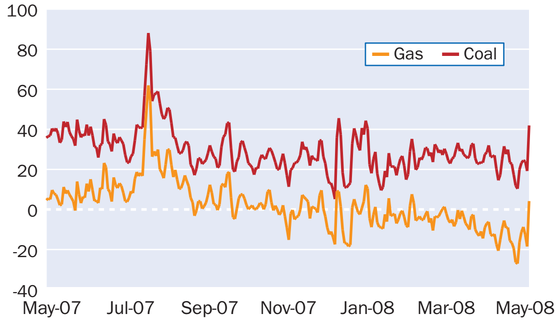
Source: Platts Emissions Daily

Cincinnati next month generating cost comparisons, profit/loss ($/MWh)



Source: Platts Emissions Daily

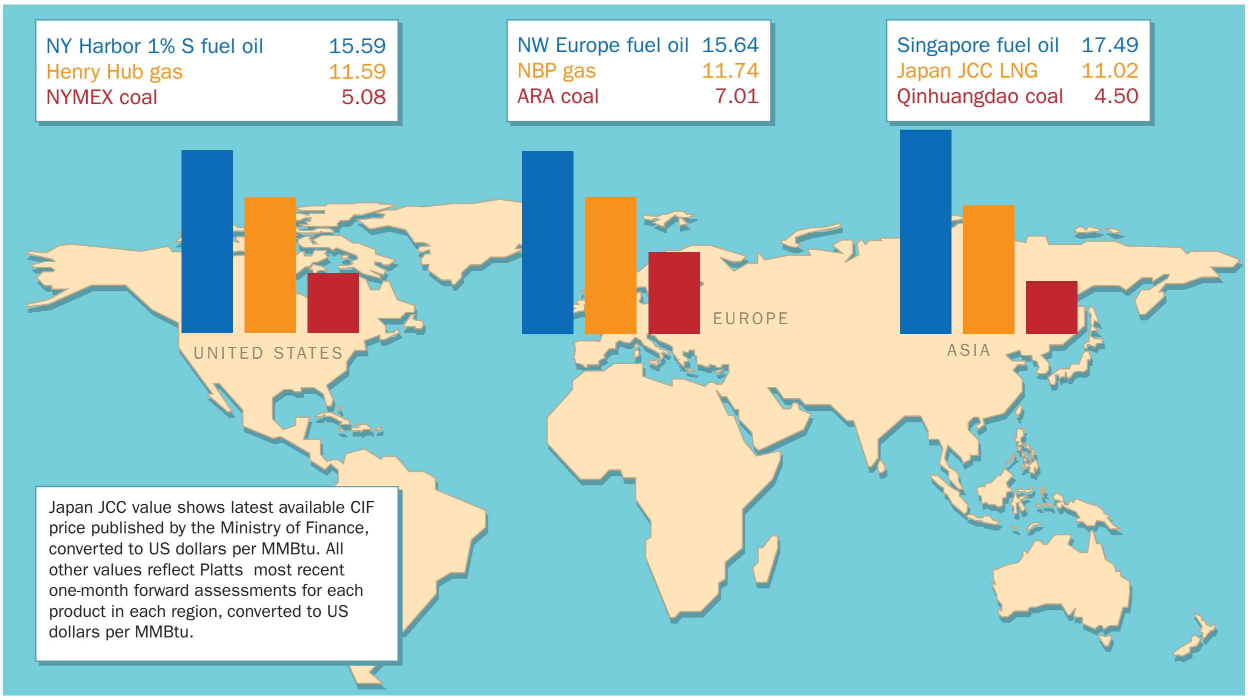
Atlanta next month generating cost comparisons, profit/loss ($/MWh)



Source: Platts Emissions Daily

NWE Note: Based on typical kg CO_2/mmBtu rates of 101.5 for coal, 55 for natural gas; and on generating efficiencies of 49% for UK gas plant, 54% for western Europe gas plant, 34% for all coal plant. Benchmark coal priced at ARA. Details of methodology at www.platts.com. US Note: Based on typical heat rates of 9,800 Btu/kWh for coal generation and 7,800 Btu/kWh for natural gas generation; no NOx controls on coal stations resulting in 0.6 lb/mmBtu NOx; benchmark coals meeting specifications for NYMEX look-alike and CSX-Big Sandy/Kanawha Central Appalachian coals, barged to Cincinnati and railed to Atlanta, respectively. For details, see methodology at platts.com.

Comparative power feedstocks ($/MMBtu) — May 23, 2008



Source: Platts LNG Daily

Natural gas prices soar

Gas prices in both Europe and the US rallied in line with the rise in crude in May, providing support to the LNG market, where prices have fallen from highs earlier in the year. The surge in Henry Hub prices to more than $11/MMBtu since the beginning of May, coupled with unusually high summer UK National Balancing Point prices, is acting as an incentive for Atlantic Basin LNG producers to focus on sales to western markets and discouraging diversion of spot cargoes to Asia.

Traders said that with Henry Hub and UK National Balancing Point prices in the mid-$11/MMBtu range, and factoring in an estimated premium of $2.50-3.00/MMBtu to cover diversion costs, Asian buyers should expect to pay around $14.50/MMBtu for spot LNG supplies. But the combination of falling seasonal demand in Asia and higher Atlantic basin prices means that spot activity has all but dried up.

In the UK, gas prices rose to all-time highs in May; winter 08 gas supplies hit 90.90 pence/therm on May 21. Summer 09 hit 79.75 p/th, placing an annual contract at 85.33 p/th. This is equivalent to about $17/MMBtu, compared with US NYMEX Henry Hub gas prices over the October 2008 to September 2009 period averaging around $11.43/MMBtu.

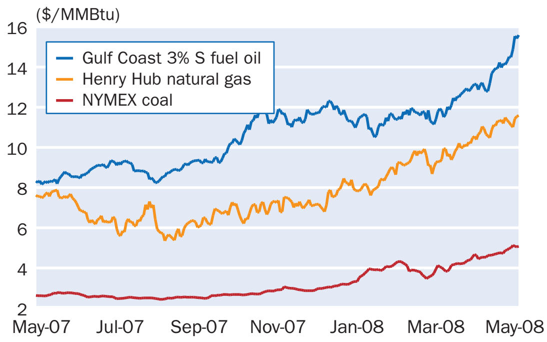
New interconnections between the UK and the Continent and the UK's increasing need to import gas is tying the UK ever more into the heavily oil-indexed continental European market. The UK, which was self-sufficient in gas in 2003, could be importing some 80% of its 100 Bcm/yr needs by 2016-17 according to estimates from system operator National Grid.

Such high prices in April and May as the market moves into summer are unprecedented and come despite low demand from continental Europe, which saw UK gas exports through the UK-Belgium Interconnector fall to their lowest level ever for May, at 68.9% below the historical average. The period has also seen a reversal of flow direction to UK importing on a few days, which has never happened during the month of May in the pipeline's entire history.

In the US, the June NYMEX gas futures contract settled May 23 at $11.857/MMBtu, its highest close in 29 months, after traders rushed to buy supplies ahead of the Memorial Day holiday. The contract then opened higher May 27 at $11.96/MMBtu as a storm threatened to develop in the US Gulf of Mexico. The contract has not settled this high since it closed at $12.283/MMBtu on December 23, 2005.

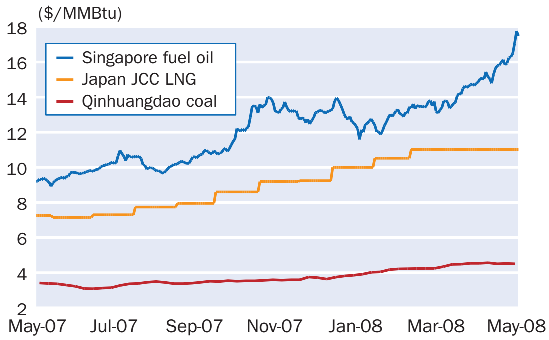
However, spot prices in some areas decoupled from futures. In the US Southwest, natural gas fell by more than $1 at some points May 23, as various weather forecasts injected an air of uncertainty into the market. Temperatures in portions of Nevada were as much as 20 degrees below seasonal norms. The IntercontinentalExchange showed prices at El Paso Natural Gas in the Permian Basin swinging between the upper $8.40s/MMBtu and mid-$9.30s/MMBtu. El Paso San Juan plunged as much as $1.50 at one point during trading to hit the mid-$7.80s/MMBtu, but has since gained following NYMEX's strong post-holiday opening.

Comparative power feedstock prices: US



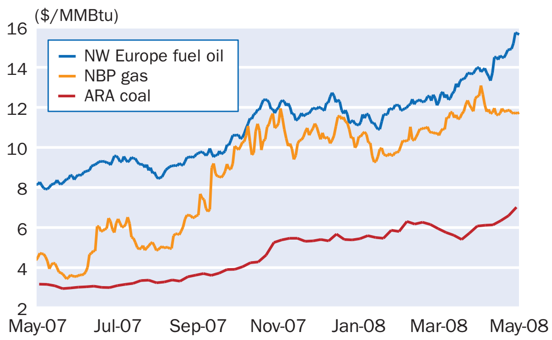
Source: Platts LNG Daily

Comparative power feedstock prices: Asia



Source: Platts LNG Daily

Comparative power feedstock prices: NWE



Source: Platts LNG Daily

Japan JCC value shows latest available CIF price published by the Ministry of Finance, converted to $/MMBtu. All other values reflect Platts most recent one-month forward assessments for each product in each region, converted to $/MMBtu.

Pacific coal market tightens

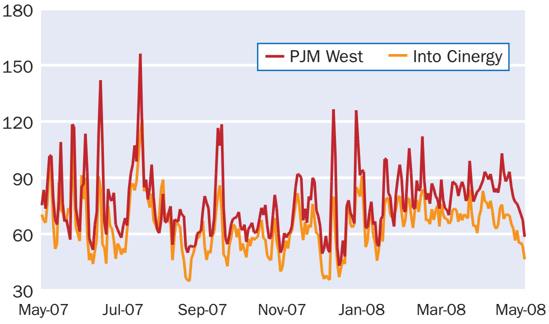
Recent global coal price increases showed little sign of abating in May, as concerns over a tightening of supply in the Pacific spilled into the Atlantic market. Despite moderate spot demand from European utilities, average delivered north-west Europe coal prices rose to $155.25/mt CIF ARA in May, compared with $138.68/mt in April. CIF ARA spot deals were heard concluded at record-high prices of over $170/mt.

While some end users have admitted their year-to-date coal-burn has risen compared with last year, most demand appears to be focused on fourth-quarter 08

UK baseload month ahead (€/MWh)

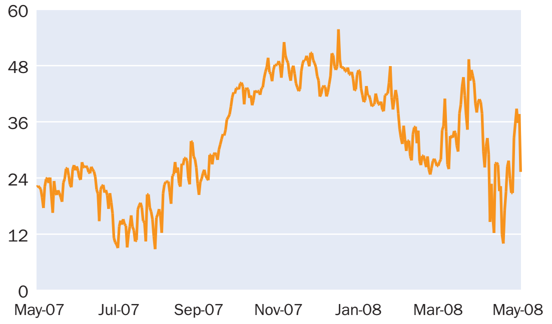
Source: Platts European Power Alert

US day ahead ($/MWh)



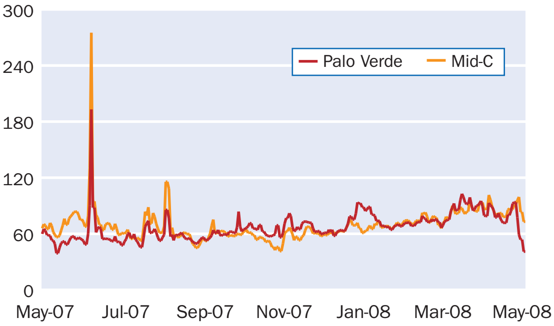
Source: Platts

Nord Pool system day ahead (€/MWh)



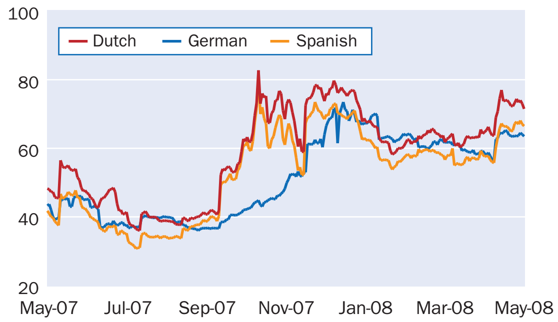
Source: Platts European Power Alert

US day ahead ($/MWh)



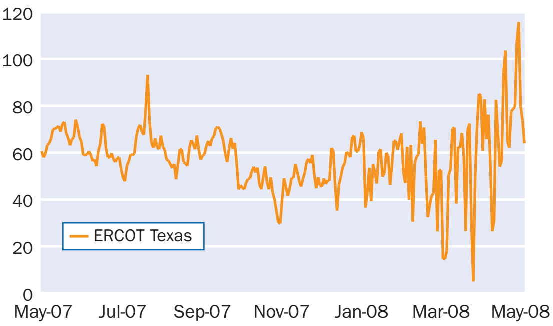
Source: Platts

European baseload month ahead (€/MWh)



Source: Platts European Power Alert

US day ahead ($/MWh)



Source: Platts

when generation margins are more profitable. Supply issues continue to be the main talking point. Producers in Colombia and South Africa are said to have sold a lot of coal forward, with trading houses understood to be sitting on cargoes expecting demand to increase in the second half of the year.

With China still assessing the cost of the tragic earthquake in Sichuan province, the effect on the coal market is materializing. Worries of a coal shortage within the country, while initially played down, have obviously helped a spike in Pacific prices, as has a ramp up in the domestic Chinese coal market. Much more ominous is the threat of a temporary ban on Chinese coal exports.

Australian FOB prices have pushed up to record high levels of over $140/mt, amid reports of strong restocking by Japanese and Indian power utilities. An increase in the number of vessels waiting to load coal off the port of Newcastle in New South Wales to over 40 ships has also fed the bullish sentiment.

The average price of South African Richards Bay FOB material in May climbed to $117.63/mt from $108.75/mt in April. Questions remain over the country's export performance for the remainder of 2008. Richards Bay prices have been remarkably resilient to rising freight costs, which have been spurred by an increase in iron ore and coal capesize fixtures in both the Atlantic and Pacific markets. Shipping analysts have forecast short-term volatility, but insist that with a new major player (Fortesque Metals group) entering the iron ore export market, rates are likely to remain firm.

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3rd Annual European Nuclear Power

Ambitions and Realities



June 30 - July 1, 2008
London, UK

Opportunities and Challenges For European Nuclear Power

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- **How Can We Make Existing Systems Last Until The New Build Era?**
- **Financing Nuclear New Build: Subsidies vs. Investments**
- **How Can We Reconcile Competitive Electricity Markets and Nuclear Power?**
- **Aging Skills and Facilities in the Nuclear Industry**
- **How Can We Solve Sourcing Bottle-Necks?**

Speakers Confirmed:

- **Vincent de Rivaz**, Chief Executive, **EDF Energy**
- **Roland Kobia**, Cabinet Member, Energy, **European Commission**
- **Francois Nguyen**, Senior Policy Advisor – Electricity Markets, **International Energy Agency (IEA)**
- **Eduardo Gonzalez Gomez**, President, **Foro de la Industria Nuclear Española**
- **Colette Lewiner**, Senior Vice President, Global Energy and Utilities, **Capgemini**
- **Philippe Herve Du Penhoat**, Head of Financial Strategy, **EDF**
- **Jack Lanzoni**, Vice President, Nuclear Power Plants Supply Chain, **Westinghouse**
- **Gerard Kottmann**, President, **Nuclear Burgundy Partnership (NBP)**
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