Energy Argus

Power Europe

TWICE MONTHLY

Electricity analysis, news, markets and regulation

VOLUME IV, 15, 12 August 2004

The quest for a price index

Will the push for an emissions index beat the move to establish an accepted power index in the UK?

Members of the International Emissions Trading Association are debating whether the EU's emissions trading scheme will need a price index when the programme launches next January. And if it does, what form that index should take.

Price indexes are an indispensable part of vibrant wholesale trading markets because they bring price discovery and transparency for participants. A price index also provides a financial reference point that companies in commodity and financial markets can use to balance their trading books — so-called "marking to market".

The evolution of price indexes has taken place over the last 30 years, and has seen the crude oil market in particular transform itself from a secretive, physical-based market dominated by a few traders with "special" contacts to a dazzlingly complex interplay between futures, swaps, physical and forward trading. At the heart of the oil market lie just a few main crude price indices.

Without an objective market price, traders can run into trouble by "marking to model" instead of marking to market. Enron traders were allowed to price off their own books, which led to the disastrous effects so well known. Enron's collapse pushed risk to the top of the agenda. The subsequent credit rating downgrades of other new entrants, the failure of TXU Europe and British Energy's brush with bankruptcy took its toll, with companies pulling out of the UK energy broking market and liquidity taking a hit.

Price indexes may inspire liquidity, but they need an underlying commodity flow. And herein lies one problem with getting a recognised power index launched in the UK.

Nine London-based brokers offering power, oil, gas and related products formed the London Energy Brokers Association (Leba) last July to address energy price indexation among other things. Brokers believe the index will help lure a greater number of financial market participants into the market to bolster liquidity.

Leba brokers send UK power market deals concluded on their screens to a company that compiles day-ahead indexes, which are published the following morning. The index's time-sensitive format was expected to give it the edge over real-time systems. It was also considered advantageous because US companies are more or less prevented from trading based on journalists' price assessments, even though the UK's financial services association feels assessments are fine. The first transaction based on the Leba index was concluded this March.

Last October, the UK Power Exchange introduced its day-ahead real-time index (Dart) as a solution for attracting liquidity in financial deals. But Dart's success depends on support from traders and a consensus from major UK brokers to claim that it is representative of the market. With their own index at hand, is it reasonable to expect this consensus can be achieved? And with so few market participants, can a futures market be supported?

In the absence of a reliable and liquid market, the best method remains "intelligent assessment" — using a market consensus to establish a buy-sell range. This method minimises the chances of distortion or inconsistency, but depends on speaking to a wide range of buyers and sellers to establish a true price range.

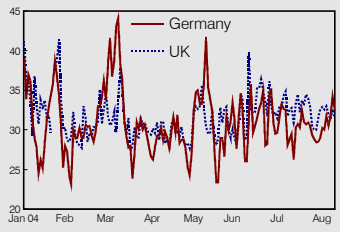
Contents

Borzen pushes south Europe exchange	2
Trading platforms spring up in Poland	3
France: Powernext needs critical mass	4
Italy: Ipex launch speeds up	4
Spain: liberalisation gains momentum	5
UK: EnDCo to enter large-user market	6
Weather/green markets	7
CDU to fight German draft law	8
German blackouts increasingly likely	8
EDP announces image makeover	9
Ireland power plants	*15-17*
Power trading markets	18-19
Argus OTC base and peak load prices	20

Day-ahead prices (€/MWh) 10 Aug

OTC (base load)	
UK	31.65
German	32.63
Dutch	34.00
French	31.13
Austrian	32.63
Swiss	32.63
Exchanges (base load)	
APX (Netherlands)	31.32
EEX (Germany)	na
EEX Phelix (Germany)	34.52
Electrabel Choice (Belgium)	31.75
Exaa (Austria)	33.00
Ipex (Italy)	62.39
Nord Pool (systemwide)	33.21
Omel (Spain)	23.52
PPE (Poland)	25.61
Powernext (France)	30.35
UKPX (UK)	32.70

Day-ahead base load €/MWh



Argus Power Europe is published by Argus Media Ltd

Main offices:
London (head office): 93 Shepperton Road, London N1 3DF
Tel: +44 20 7359 8792 Fax: +44 20 7226 0695
e-mail: ape@argusmediagroup.com
e-mail: sales@argusmediagroup.com
Houston office: 4801 Woodway,
Suite 270W, Houston, Texas 77056
Tel: +1 713 622 3996 Fax: +1 713 622 2991
New York office: 129 Washington St,
Suite 200, Hoboken, NJ 07030
Tel: +1 201 659 4400 Fax: +1 201 659 6006
Washington office: 1012 Fourteenth Street NW,
Suite 1500, Washington, DC 20005
Tel: +1 202 775 0240 Fax: +1 202 872 8045
Singapore office: 22 Malacca Street, #10-02 Royal Brothers Building, Singapore 048980
Tel: +65 6533 3638 Fax: +65 6533 4181
Moscow office: ul. Prechistenka 40/2, entr 2, Floor 7, Moscow 119034, Russia
Tel: +7 095 933 7571 Fax: +7 095 933 7572

Chairman: JA Nasmyth
Publisher: Adrian Binks
Business development: Peter Caddy, Jim Nicholson (Europe, Middle East, Asia-Pacific), Daniel Massey, Miles Weigel (Americas)
Commercial manager: Barbara Kalu
Editor in chief: Ian Bourne
Managing editor: Euan Craik
Editor *Argus Power Europe*: Cindy Galvin

Editorial
London: Denise Albrighton, Nick Black, Charlotte Blum, Neil Campbell, Helena de Chair, Richard Child, Sean Cronin, Tom Cousins, Elizabeth Cowley, Marco Denes, Paul Dobson, James Gard, John Gawthrop, James Gooder, Daniel Hayes, Hilde Hjertenes, Owain Johnson, Chris Judge, Samira Kawar, Alan Kennington, Rafiq Latta, Daniel Lester, Alastair Martindale, Phil Newby, Claire Pickard-Cambridge, Stephen Pink, Linda Pogson, Peter Ramsay, Tom Reed, Therese Robinson, Nina Roehrbein, Mat Stone, Vanessa Viola, John Walsh, Emma Wenban-Smith
Washington: Peter Rosenthal (bureau chief), Ross Allen, Mike Ball, Steve Campbell, Abby Caplan, Carli Flippen, Peter Gardett, Caroline Gentry, David Givens, Kristina Lippert, Simon Lomax, Steve Marcy, Hannah McCall, Christopher Newman, Larry Pearl
Houston: Stephen Burns (bureau chief), Keefe Borden, Jena Honeycutt, Huma Khan, Jeff Kralowetz, David Love, Tim Mingee, Yaser Qasem, Cyrus Sanati, Amanda Smith, Matthew Wood
New York: Pamela Kevelson, Matthew Monteverde, Nasreen Tasker, Valerie Volcovici
Singapore: Jason Feer (bureau chief), Azlin Nur Ahmad, Karen Chur, Richard Davies, Ronnie Hau, Trisha Huang, Emril Jamil, Xie Liqin, Weilyn Loo, Sunita Sharma, Irene Tang-Tay, Paul Wood
Moscow: Maria Zabralova (bureau chief), Mikhail Perfilov, Natalia Bortsova, Yekaterina Gaidanskaya, Rauf Guseinov, Oleg Kirsanov, Dmitry Kleshchevnikov, Alice Lagnado, Maxim Nesmelov, Svetlana Novolodskaya, Kirill Portnov, Mikhail Tsovma, Alexander Yershof
Berlin: Chloe Jardine **Caracas:** Robert Campbell **Dubai:** Paul Mollet **Kyoto:** Rieko Suda **Paris:** Helen Avati **Santiago:** Patricia Garip-Bertuol **Tokyo:** Masaki Mita

Chief sub-editor: Mark Lunn
Sub-editors: Alisdair Bowles, James Leech, Simon Martelli
Production manager: Ricardo Collison,
Production: Ravin Khurtoo, JC Lanoë, Chris Rockett

Sales and marketing
Richard Cretollier, Jacob Henriksson, Seana Lanigan, David Lyon, Pulvi Popat, Maria Scappaticci, Nicola Scott, Andre Vanderputt, Anastasia Vengerova (London), Vyacheslav Mischenko, Tatyana Pastushenko, Yelena Timofeeva (Moscow), Chris Bozell, Peter Brown, Karen Johnson, Robin Saikin (Houston), Howard Walper (Washington), Jessica Ng, Josephine Ong, Feisal Sham, Sharon Tang (Singapore)

ISSN 1476-640X Published twice monthly

THE QUEEN'S AWARDS FOR ENTERPRISE 2002

Borzen spearheads regional exchange

Slovenian power exchange Borzen is taking the lead in co-ordinating the development of a regional electricity market in southeast Europe (SEE), with the second phase of meetings scheduled for this autumn.

"Our government has recently issued a decree supporting our efforts and the Athens Forum process," says Borzen head Damjan Stanek. "We want to make good use of the political momentum that has developed due to our past activities."

Such support is important, Stanek says, as he is meeting primarily with government officials in other SEE countries to discuss framework issues. Initial thinking envisions a Borzen South-Pool exchange that could involve countries of the former Yugoslavia, with other nations free to join later on. Give the experience of other markets, the volume on South-Pool could reach 10TWh a year.

The European Commission held the last Athens Forum in June this year, during which it proposed a three-step process for developing an SEE exchange. The development of legislative, regulatory and technical rules for each national market are to be completed in the first phase, which ends at the end of this year.

By the end of the second phase in December 2007, regional aspects — including investments, market design, licensing and trading mechanisms — are to be completed. The third phase begins in January 2008 with the launch of the exchange.

"Borzen is taking the lead because it is the only day-ahead trading exchange in the region," Stanek says. While one exchange is preferred, there is scope for additional involvement. For example, Opcom — Romania's energy market operator — could run a balancing market, while Borzen focuses on day-ahead and financial trading. But Stanek says the advantage for the region is to create synergies and avoid having several national exchanges — each of which has few participants and low liquidity.

An SEE exchange that attracts 3-5pc of the region's total consumption is considered a good target for the first stage, he says, while having up to 50 participants is also considered feasible.

Interconnections between the SEE countries are sufficient to handle trading and there is no congestion in the region. Stanek says this is based on a Borzen study that looked at how spot trading could impact the economic and technical aspects of power flows in the region's networks.

While electricity is the prime focus of the exchange, Stanek says there have been discussions about expanding into gas and possibly green products. But there are other issues to tackle first, such as which currency to use.

"For now, we are the only EU country in the SEE, and when other countries in the region join, a lot of bureaucratic obstacles will fall. There are, for example, cash settlement and tax issues. These might be considered small things, but on the other hand, they are big things for the people who are dealing with them on an operational basis," he says.

Out of sync

There is also the issue of liberalisation, which varies by country. Romania is ahead of Bulgaria, Stanek says. In former Yugoslavia, Croatia and Montenegro have passed an energy law, while Serbia is in the final stages of adopting its energy legislation. But, despite the differences, all of the SEE countries have committed to energy liberalisation, he says.

Borzen's trading volumes this year are about 14pc lower than in 2003, Stanek says. The key difference is that end-users linked their electricity prices to Borzen last year when prices rose by 30pc compared with 2002. This year, those users opted against tracking Borzen prices to avoid the price risk. Slovenia's prices tend to track those on Germany's EEX exchange and the correlation is getting stronger.

Last year, the price differential between the two markets was €7.43/MWh, while this year the difference is only €0.43/MWh, Stanek says.

Small trading platforms spring up

The number of independent trading exchanges in Poland is on the rise. Participants blame the state-owned Polish Power Exchange (PPE), suggesting that it has failed to attract sufficient trading volumes in the four years since its launch.

One of the latest exchanges to begin trading is Polska Energia, which was established this spring by electricity generator Poudniowy Koncern Energetyczny (PKE). But energy market participants predict that other generators will follow suit, as they view trading exchanges as an efficient way of selling their power into the liberalised power market.

Electricity generator Elektrownia Rybnik is testing its trading exchange now, while Elnord — a company owned by eight electricity distributors located in northern Poland — has said it is also planning to launch an exchange. They would join two other exchanges that are already operating — Platforma Obrotu Energia Elektryczna (POEE) and Kantor Energii (*see table*).

'Growing interest'

"There is growing interest, especially among generators, to establish their own trading platforms," says Jacek Bogumil, sales manager of Energo-Tel, a company that sells software for energy trading platforms.

The Polish government established the PPE in 1999 and the state still retains an interest of more than 22pc in the exchange. The rest of the shares are owned primarily by local electricity distributing companies. Trading volumes this year have stabilised at around 5,000-6,000MWh daily, down from the average of 7,000 MWh/d seen in 2003. In earlier years, volumes fluctuated between extremes of 2,000-10,000 MWh/d.

In June, the PPE's volume reached some 160,290 MWh, or around 1.65pc of the country's total electricity consumption. When launched, the exchange's goal was to have a turnover representing a 6pc share of Poland's total energy consumption.

The PPE says volumes have declined this year because of consolidation among regional distributors, such as the merger of five northwestern electricity distributors into a new company called Enea (*APE, 17 June, p4*). This consolidation has had the effect of reducing the number of trading parties. But despite its declining volumes, the PPE's turnover still exceeds the volumes seen on the other exchanges, although a comparison with Polska Energia is impossible because the company does not publicise its data.

Kantor Energii's average turnover is about 15,000 MWh/month, according to Tomasz Krzyzewski, the company's director of energy trade. And POEE's monthly turnover averages 30,000-50,000MWh, says company trade specialist Jaroslaw Gierula.

The main reason for private exchanges' increasing popularity, according to energy market participants, is their relatively low trading cost. Participants trading on the PPE must pay an annual fee of 130,000 zlotys (€30,000), compared with the 500 zlotys that POEE charges, although the latter charges a higher commission per trade fee than the PPE.

Another reason for the popularity of the smaller exchanges is the low liquidity and transparency of the energy market, says Krzyzewski.

While such a low level of liquidity begs the question of whether so many trading platforms can be supported, defendants of the system suggest that each exchange has its own particular niche.

"POEE and JAC EnTra [Kantor's operator] operate very differently from each other and do not really compete with the PPE," says Witold Szwagrun, president of the cire.pl website, which specialises in energy market news.

Exchanges

POEE
Poland's oldest private trading exchange, Platforma Obrotu Energia Elektryczna (POEE) began operating in March 2001. The exchange does not buy or sell electricity, but instead offers a trading platform for buyers and sellers to conclude transactions directly with one another. POEE trades mostly day-ahead contracts, but it also offers futures contracts. The exchange charges an average commission of 0.5 zlotys/MWh (11 eurocents/MWh) traded. POEE is owned by Elbis, a subsidiary of electricity generating company Elektrownia Belchatow, which has around 4,300MW of installed capacity.

Polska Energia
Poland's newest exchange, Polska Energia began operating in the spring. The platform buys and sells energy, but does not reveal turnover or commission charges. Polska Energia's main shareholder is PKE, an umbrella company that consists of eight coal-fired generating firms whose combined installed capacity is some 5,055MW.

Kantor Energii
The only independent exchange that is not affiliated with an electricity generator, Kantor Energii began operating in January this year and offers day-ahead and two-day ahead contracts. The exchange — which buys energy from producers for sale to buyers — has seen average daily volumes of 500MWh since it began. Sales are made during two daily trading sessions — one in the morning session, which lasts for one hour and 45 minutes, and an afternoon session, which lasts for an hour and 30 minutes. Trading is continuous throughout both sessions. Kantor operator JAC EnTra is owned by former traders from Enron Poland.

Polish Power Exchange
Formed in 1999, day-ahead trading on the Polish Power Exchange (PPE) began in June 2000. The exchange also offers futures trading for physical delivery.

Powernext strives for critical mass

French power exchange Powernext achieved steady growth in volumes over the past year, with trading volumes for the first six months of this year double what they were in the same period in 2003.

On 1 June, the exchange recorded its highest volume, 57GWh, followed by 55.5GWh on 12 July. But these figures still represent less than 5pc of France's total daily power consumption and are dwarfed by the average 240GWh that trades daily on Germany's EEX exchange.

The 1 July opening of the French commercial and industrial market to competition promised to bring new players to the French market. But hopes that this would bring a tidal wave of liquidity to the spot market were soon dashed.

"Liberalisation?" says Thierry Carol, the head of sales and marketing for the exchange. "What liberalisation?"

Day-ahead volumes averaged 40.7GWh in July, down by 1.5pc compared with the 41.4GWh average seen in June, although this is less than the 6.1pc decline seen for the same two months last year. In comparison, over-the-counter trading volumes in day-ahead power declined by 17pc month-on-month, with an average 23.59GWh traded daily in July this year.

"No, there has not been a large change in volume since 1 July," Carol says. "Of course, we are the wholesale market, so there is no direct link between us and end-users, when we are talking about the bakery and the office around the corner. But new suppliers are growing more active in the market, and we think that this could really increase liquidity."

Powernext is banking on new members — such as supply company Poweo, which began trading last month — to increase liquidity. Media campaigns ranging from television advertising to sponsoring football team Paris St Germain, have yielded only 2,400 customers for Poweo so far, but the company takes a long-term view.

"Nobody can expect these things to happen overnight," says spokesman Christophe Droguere-Poncelet. "If we pass 12,000 customers by the end of this year, we will pass our target." That target represents just 0.3pc of the newly liberalised French power market.

Resilience index

"It is long process for new participants to reach critical mass. It is also a long process for us to increase our proportion of that liquidity. We cannot attract 100pc of the volume in a single day," says Carol.

Powernext traders are most concerned about being able to trade without impacting the market. "Our 'resilience index' test shows that, even if you inject a large order of around 500MW to the Powernext order book, the price impact is something like €2-3/MWh. But, with more liquidity, it would be even smaller. In that way, with higher liquidity, we expect not just to increase our volumes in line with the market, but actually increase our share," he says.

Successful tests could fast-forward Ipex launch

The final test phase of Italy's electricity exchange is showing positive results after just one month, so it could launch before the end of the year, according to market operator Gestore del Mercato Elettrico (GME).

Interest in the final phase is high considering that the tests are taking place in just three of the 20 regions that make up the Italian peninsula — Marches, Tuscany and Umbria — GME chief executive Sergio Agosta tells *Argus*. The other 17 regions will join by September.

While about 50 participants, including wholesalers, traders and utilities, asked to participate in the final phase, about 30 have followed through. Agosta, who joined GME last November after a stint as a manager at renewable energy firm EnerTAD, says he is encouraged by the results. Since launching its first test phase in March, Ipex has captured nearly 30pc of the total electricity sold in Italy. Of the 25.2TWh sold across the peninsula in June, slightly more than 7TWh, worth €545mn, traded on the bourse, a rise of 4.2pc from the previous month.

GME was established by Italy's transmission network operator GRTN in June 2000. The government approved the exchange's initial operating procedures and rules the following June, but progress stalled when it came to ruling on revisions. The latest launch date is pencilled in for January 2005, but Agosta says this could move forward if the test results remain positive. But he does not foresee this happening before November.

Agosta blames Italy's relatively high electricity prices on the fact that 70pc of its generation comes from hydrocarbons. Responding to criticisms that the exchange is also generating relatively high prices, Agosta notes that they are not significantly different from the prices that would have been seen under the previous state-administered tariff system. While the average Ipex price in June was €67.84/MWh, the tariff would have been €67.54/MWh. And in May, the Ipex price averaged €47.81/MWh, compared with €49.64/MWh that would have resulted from the previous system.

But Agosta concedes that Ipex prices are higher than those on Europe's other electricity exchanges. While the weighted average price for day-ahead base-load power cleared at €55/MWh on 31 March, Ipex's first day of operation, the same contract closed at €25.89/MWh on France's Powernext exchange and at €26.15/MWh on Germany's EEX.

"The electricity exchange projects things as they stand, providing a real and representative price of the existing generation system," Agosta says, adding that the exchange benefits will build gradually over a 12-18 month period.

"Honestly, it would have been impossible to expect better over such a short period."

Liberalisation moves into large consumer market

Renfe, Spain's rail operator and the country's largest electricity consumer, has invited nine domestic and international utilities to bid to supply its power needs in 2005.

Endesa, Iberdrola, Union Fenosa, Gas Natural, Hidrocantabrico, Viesgo, the UK's Centrica and small domestic generators Hispaelec Energia and Nexus Energia have until 16 September to submit proposals to supply all or a part of Renfe's needs. The first six on the list provided the rail firm with 2.23 TWh last year under a contract worth €136mn.

State-controlled Renfe is unique among Spain's industrial consumers as it owns most of its own electricity cables, saving on distribution costs. But despite this advantage, observers believe the firm's electricity bill in 2005 will probably match what it is paying this year as Spain's industrial prices have stabilised or declined, relative to the country's inflation rate, since the government liberalised the large-user market in 1998.

While inflation has risen by about 15pc since 1999, power prices have gone up by 2-5pc in the same period, according to Francisco Ruiz Morote, director of the Madrid office of consultancy GE & PE Ingenieria, which advises industrial users on ways of reducing their energy bills.

Ruiz Morote's estimates only take into account the prices seen on the Omel spot market, where most industrial users buy their electricity. In the fixed-tariff market, where a small group of especially large consumers — such as Renfe and steelmaker Acerinox — buy their power, prices have risen by only 1.8pc annually since 1999.

The fixed-tariff consumers pay about 4 cents/kWh while Omel users pay roughly 2-3.5 cents/kWh.

Explaining the five-year price stabilisation, Ruiz Morote says that, soon after 33pc of Spain's larger-user market was liberalised in 1998, prices declined by up to 15pc as retailers scrambled to offer competitive tariffs to retain customers.

'Testing the market'

When the rest of the market was opened to competition in January 2003 — allowing about 450,000 businesses and millions of residential clients to switch suppliers — retailers again rushed to trim prices, this time by as much as 3pc. The reductions were less dramatic, Ruiz Morote adds, because retailers "have been merely testing the market" before devising commercial strategies for the growing small-and-midsize business sector, known as Pymes. This could mean further price reductions by 2007, the date by when the residential market must be opened to competition according to the EU's electricity directive.

"Liberalisation has worked, not as much as many people would have liked it to, but it has certainly worked in lowering power prices," Ruiz Morote says.

But some complain that prices are still not low enough. Francisco Perez, energy director for chemical industry federation FEIQUE, says Spanish chemical firms pay significantly more for power than their peers in France or the Netherlands.

"When we compare the Rotterdam chemicals pole with Tarragona, they have much better prices, which have helped attract a lot of customers," Perez says. "Even a three to four percentage point difference can influence a firm's investment decision. Our energy costs are not as bad as before liberalisation, but they are still higher than the European average."

One way to lower Spain's energy prices would be to increase interconnection with France and Portugal, helping to end the country's "energy island status", and hastening the creation of a true European power market, Perez says.

Ruiz Morote agrees. "In the centre of Europe you have a big producer, France, whose power prices are 35pc lower than Spain and which has an impact on the whole European market. But the French try to keep all the capacity to themselves, and it would help if they shared a bigger piece of the pie," he says.

'Liberalisation has worked, not as much as many people would have liked it to, but it has certainly worked'

The fledgling Iberian power market Mibel will not help lower Spanish tariffs anytime soon, Ruiz Morote suggests. The two neighbouring nations need to develop their retail networks and boost interconnection levels, he says. Plus, Portugal's energy prices are higher than in Spain.

"The only way I see prices falling is if [electricity] retailers cut their operation costs, but right now they are building their networks [in Spain and Portugal] so I don't see this happening in the near term," Ruiz Morote says.

Retailers — which control the Omel procurement process by buying at market prices and reselling at fixed rates — are mostly owned by Spain's big three power utilities, Endesa, Iberdrola and Union Fenosa, which together control over 90pc of its generation and distribution business.

Ruiz Morote adds that, even though Spain is working to boost cheaper combined-cycle power capacity, the market is highly dependent on volatile natural gas prices, which could add to their cost equation.

Spain's burgeoning renewables industry will also make no difference in cutting prices, Ruiz Morote explains. "These alternative technologies are good for the environment, but they are not necessarily cost effective."

German Dominguez, a senior consultant for McKinsey's in Madrid, agrees that power prices could fall if retailers lower their cost base. Otherwise, there will have to be "brutal" competition in generation for prices to come down, and this is unlikely to happen unless an abnormal situation creates overcapacity in the system. "Retailers have very thin margins and its going to be very difficult to raise them if generation prices remain the same," he says.

For the next three years, Spain's industrial power prices are likely to remain stable and below the inflation rate, Ruiz Morote says. "Tariffs will stay in the same level and under the average price rise. In the undeveloped Pymes market, they'll probably fall by an extra 3-4 points from last year."

EnDCo prepares entrance to UK's large user market

Dutch energy trading and consulting outfit the Energy Data Company (EnDCo) is poised to make its debut in the UK power market, offering large industrial users a fast track to the wholesale market.

The managing director of the UK operation, Les Abbie, says the company's Netherlands experience, where it claims to serve 10pc of industrial consumers, will be deployed in the UK by the end of this year.

"We will help large buyers bypass traditional suppliers by helping them procure power directly from the wholesale market," he says from EnDCo's Chelmsford office in south-east England.

The company assesses a user's consumption profile, and matches its requirements with a portfolio of long and short-term wholesale contracts. With wholesale prices firming, EnDCo judges that now is the time for industrial consumers to begin taking market risk upon themselves, with its help and for a fee. "Clients will pay a monthly retainer and a pence per MWh traded commission," Abbie says.

This approach has proved successful in the Dutch market, where some clients have saved up to a 10th on their purchases. Abbie believes the tradition of signing fixed-price contracts with utilities is becoming superfluous in Europe's liberalised power market.

EnDCo's marketing manager in the Netherlands, Monique Mesman, says the company handles the accounts of one in 10 large Dutch consumers — companies that use over 100GWh/yr.

EnDCo has also been tempted into other markets — Belgium and Germany last year and now the UK — because multinational companies using its services in the Netherlands are keen to employ the same system elsewhere.

EnDCo was established in 2000, and its UK subsidiary was set up last year, but but winning clients is a slow process. "We are not yet in a position to act in the UK market, but we are consulting and advising, and learning about our clients' portfolios," Abbie says.

The UK market throws up different challenges than the Netherlands market, Abbie says. Some UK users are risk-averse and more inclined to stick with fixed-term contracts. But EnDCo aims to overcome this by managing a small proportion of a client's supply and demonstrating the benefits, then increasing its involvement in tandem with the client's appetite for risk.

Abbie says EnDCo sees itself as a trailblazer in the UK market. Consultancies may overlap with some of its work in advising clients on certain issues — such as on-site generation and aggregated consumption — but in terms of facilitating a client's direct engagement with the wholesale market, no one else is doing it yet, he says.

Legal necessity

Already a licensed power supplier, the UK operation hopes to get master registration agreement accreditation by the end of October — a legal necessity for trading in the UK's wholesale market. Trading would then start by the end of this calendar year.

UK regulation limits the company to dealing in the physical market until it gains approval under the Financial Services Act (FSA) to give advice on derivatives and other financial instruments. FSA approval is expected by the middle of next year. "The financial authorities in the Netherlands are not so demanding," Abbie says.

The trading operation will remain in the Dutch office unless it is deemed better to have a presence in the UK. This has worked so far for EnDCo's fledgling operations in Germany. But there are five staff in the UK scoping out potential clients. Abbie concedes that there is a contradiction at the heart of the company's business plan.

"In a sense, the more successful we are in convincing clients of the benefits of dealing in the wholesale market, the less they will need us to do it for them," he says. But he adds that, for the moment, there are few signs that this will happen any time soon.

Fourth-quarter spark spreads surge on oil impact

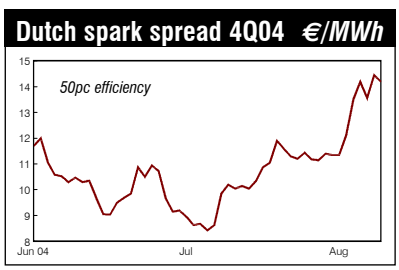
A different perception of the impact of soaring oil prices has caused significant shifts in the 4Q04 spark spreads in the UK and the Netherlands.

Given the six-nine month time lag on oil-linked gas contracts, fourth-quarter gas contracts have been less responsive to upward pressure, especially as weak prompt and summer month prices have reduced their upside.

At the NBP, the 4Q04-1Q05 spread has moved out to 6.65p/th, while on the TTF, 1Q05 has surged to record levels at almost €16/MWh, while 4Q04 has struggled to move above €14/MWh. In contrast, the power fourth quarters in both countries have been subjected to a flurry of buying, mainly attributed to oil, with an added contribution from buoyant coal.

The spark spreads have seen significant upside. In the UK, the 4Q spark breached £5/MWh on 30 July, for the first time since 2 January, and has remained above that mark ever since. And the 4Q04 spread has also been given support by neighbouring September, which has seen its spark spread at unprecedented levels above £8/MWh.

In the Netherlands, the spark spread has seen even greater movement. From under €9/MWh on 7 July, the spread has surged to break through the €14/MWh barrier, a 67pc gain in 23 working days.



June-July weather trades

Contract	Period	Price/HDD†	Price/CAT#	Option	Date
London	Jun		514		1 Jun
London	Jun		1,600	Put	1 Jun
				5 x 1	£95,000
London	Nov-Mar	1650		Put	2 Jun
				2.5 x 187.5	£60,000
London	Jun		500	Call	2 Jun
				1 x 2	£15,000
London	May-Sep		2550/2650	strangle	2 Jun
				5x1	£125,000
London	Jun		520		4 Jun
London	Jun		525		7 Jun
London	Nov-Mar	1666			7 Jun
London	Nov-Mar	1666			16 Jun
London	Jul		595		17 Jun
London	Jun		525		18 Jun
London	Jun		526		18 Jun
London	Aug		620	Call	18 Jun
				10 x 1mn	£65,000
London	Jun		524		21 Jun
London	Jun		525		21 Jun
London	Nov-Mar	1666			21 Jun
London	Jul		596		23 Jun
London	Jul		595		23 Jun
London	Aug		595		23 Jun
London	Jun		526		24 Jun
London	Jun		526		24 Jun
London	Jun		526		24 Jun
London	Jun		526		24 Jun
London	Jul		574		30 Jun
London	Jul		558		5 Jul
London	Aug		599		7 Jul
London	Nov-Mar	1675/1725		strangle	7 Jul
				5x1000	£240,000
London	Jul		556		12 Jul
London	Jul		557		13 Jul
London	Jul		553		14 Jul
London	Aug		595		19 Jul
London	Jul		558		20 Jul
London	Jul		558		20 Jul
London	Jul		555		21 Jul
London	Nov-Mar	1665			26 Jul
London	Jul		556		28 Jul
London	Aug		608		29 Jul
London	Aug		607		29 Jul

†HDD heating degree days (centigrade)
#CAT cumulative average temperature
**CME Chicago Mercantile Exchange trade* — *Brokers*

Green markets — July

ETS hit by Nap approvals

The European Commission's unconditional acceptance of eight of the EU 15's national allocation plans (Naps) triggered a bear run in the EU emissions trading scheme (ETS) in the first week of July.

Certificates for 2005 delivery fell from their late June support levels of €9/t of carbon dioxide equivalent (CO_2e) to below €8/t CO_2e, and never fully recovered.

Despite many participants being away for the month, trading remained liquid as speculators sought to gain from the scheme's new-found volatility.

Mid-month, the profit-taking halted at the €7.40/t CO_2e level, and a wave of buyers boosted the price up to around €8.50/t CO_2e, where it has held more or less steady into the first week of August.

Volumes have swelled over the period, with players now more inclined to trade in blocks of 10,000t, as opposed to the 5,000t units that were common currency previously. On 18 July, a single-day record of 10 trades was reported, with a further six seen the following day.

At the end of the month, Shell International Trading and Shipping and Barclays Capital Investment concluded a deal using the International Swaps and Derivatives Association (Isda) agreement, the first such trade involving a non-bank counterparty.

As more large participants approach the ETS market, and liquidity builds, its characteristic volatility is likely to be ironed out.

At the end of July, the market for 2005 allowances were quoted at €8.40-50/t CO_2e, and by 10 August, this had swelled gradually to €8.50-8.70/t CO_2e. An emerging contango in the allowances for 2006 and 2007 had been flattened, with both quoted at €8.40-8.80/t CO_2e.

Traders predict that if the price hits €9/t CO_2e again, a further flurry of speculative selling may ensue.

Renewable obligation certificates

UK non-co-fired Rocs for the second compliance period (CP2) hit a record high of £52.07/MWh in a Scottish auction in mid-July.

After that, interest in the period withered and attention shifted to CP3, which remained steady at around $43-45/MWh into August for both co-fired and non-co-fired certificates.

Bids also surfaced in CP4 at the end of the month, softening from £38.50/MWh to £38/MWh and lengthening the backwardation that is emerging in the market.

Dutch biomass certificates

Bearish moves were seen in the market for Dutch biomass certificates, with the quarter three 2004 slipped from their June levels of €6.25-6.50/MWh to establish a new spread of €6.15-6.35/MWh. The certificates continued to trade occasionally, but are expected to remain range-bound.

Indicative prices	5 Aug	
UK prices	**Bid**	**Offer**
UK emissions (*£/t CO2e*)	3.30	3.80
UK Roc (*£/MWh*)		
Compliance Period 2	51.75	53.00
Compliance Period 3	43.00	45.00
EU allowances (*€/t CO2e*)		
Emissions	8.60	8.75
Dutch GCB green certificates (*€/MWh*)		
Wind (domestic)	6.00	7.00
Biomass*	6.15	6.535
**Bark and black liquor*		
Swedish Elcertificat (*SKr/MWh*)		
For March delivery 2005	234	235

Swedish certificates

Certificates for March 2005 delivery saw more volatility than is customary as many participants were away.

In mid-July, the certificates went through at 232.75 krone/MWh, down by over SKr3/MWh from the beginning of the month and the lowest levels seen since early May.

By the end of July, the prices had perked up on steady buying interest, and in the first week of August they had regained their more familiar SKr234-235/MWh levels.

The Nord Pool's market for immediate delivery was not affected by the fluctuation, remaining static at SKr231-232/MWh over the period.

CDU to fight German draft law

Now that Germany's Social-Democrat/Green government has agreed on a cabinet draft of the country's energy law, attention is turning towards the Christian-Democrat (CDU) opposition party, which is vowing to fight several key aspects of the bill.

The bill, which details the remit of the new energy regulator, will go to both houses of parliament in September. The CDU will push for a stronger regulator and for stricter efficiency guidelines in calculating grid access fees at an expected 24 September upper house reading. The party, which is traditionally more business friendly, fears the law in its current version "will mainly cement the status quo" by keeping grid access fees too high.

The economy ministry, under pressure from Brussels to get the energy law passed, decided on a compromise that includes all methods for calculating grid fees. But energy users and traders say that including costs in this calculation will take away the incentive for grid companies to keep costs down.

Opposition leaders are also calling for the regulator to be given more say in setting access fees. The regulator should not set every fee — an administrative nightmare given Germany's roughly 1,600 grid operators — but it should be able to approve them in advance, they argue. This demand was also put forward by Germany's monopoly commission in a recent report that was scathing about the lack of competition in the country's energy sector.

Most believe the energy law will be passed to the mediation committee for both houses of parliament, from which a compromise will emerge — the result of which is anyone's guess, says energy expert Boris Scholtka from law firm Kermel & Scholtka.

Scholtka says that more far-reaching demands, such as efficiency criteria, look less likely to succeed than benign calls for more comparisons between grid access fees. The fact that the CDU's Bavarian sister party, the CSU, is less keen on efficiency criteria for fear of jeopardising investment security, while on the other hand calling for a greater say for the 16 federal states in regulatory issues, will further complicate matters.

The CDU plans to publish a comprehensive energy policy paper next month. This will criticise the strong environmental stance of current policy, and call for a rethink on phasing out nuclear plants. The party will also call for responsibility for energy policy to revert to the economy ministry, to end the constant fighting between the environment and economy ministries and ensure a "co-ordinated energy policy". These thoughts will be echoed by another policy paper that the German chambers of commerce and industry expect to publish at the end of September. This paper is also expected to focus on the nuclear phaseout, in addition to the lack of incentives-driven efficiency in the renewables sector.

German blackouts increasingly likely

One year after the US blackouts, and six weeks after implementation of the EU regulation on cross-border power trading, bottlenecks at Germany's borders are getting so bad that blackouts are a distinct possibility, warns Rudiger Winkler, a director and electricity consultant with consulting firm IfED.

The situation is deteriorating because cross-border trading is increasing as participants seek to benefit from arbitrage opportunities by delivering Czech power to German customers, and because of the rapid increase in wind-power capacity being connected to Germany's northern and northeastern high-voltage grids.

A key remedy is to oblige transmission grid operators to reinvest the proceeds from cross-border grid users in the critical bottlenecks, says Winkler. IfED studied the topic on behalf of six German-based power traders, including the power-trading arm of Czech incumbent CEZ, Munich-based RPG Energiehandel and Dusseldorf-based Statkraft Markets, a subsidiary of Norwegian power giant Statkraft.

The study, which Winkler describes as a "to-do list" for Germany's future energy regulator, calls for more transparency on the use of proceeds from transmission system operator auctions and the exact location of bottlenecks. It will be presented at the Emart conference in Barcelona this November.

EU large user electricity rates

Industrial user prices have increased by 1-3pc in Belgium, France, Germany and the UK since April, but decreased in the Netherlands by 2-9pc — depending on the maximum demand category — and in Spain by 3-6pc, according to recent assessments published by Energy Advice (EA). There have been tax increases on electricity in Italy at the 500kW level in the past few months, while in Belgium certain levies for nuclear decommissioning and emissions reductions have been reclassified as taxes. EA's prices are categorised as ranges of high, low and representative to reflect load factor, increased competition and regional differences. But the assessments also reflect the fact that reliable price information is becoming difficult to obtain in some cases.

April price comparison (excluding tax) *eurocents/kWh*

Maximum demand		500kW	10MW	80MW
Belgium	Low	7.21	4.63	3.91
	High	8.86	6.21	5.15
	Representative	8.09	5.59	4.65
France	Low	4.75	4.12	3.54
	High	6.64	5.68	4.20
	Representative	5.83	4.85	3.80
Germany	Low	6.50	4.55	4.35
	High	9.24	6.30	6.02
	Representative	7.68	5.93	5.38
Great Britain	Low	5.28	4.38	3.76
	High	6.59	5.07	4.46
	Representative	5.74	4.74	4.37
Italy	Low	8.42	5.01	4.54
	High	9.25	6.60	6.04
	Representative	8.84	6.04	5.44
Netherlands	Low	6.17	4.57	4.10
	High	7.38	6.43	6.05
	Representative	6.76	5.55	4.85
Spain	Low	5.27	4.62	3.76
	High	6.01	5.11	4.55
	Representative	5.64	4.76	4.14

— Energy Advice

Austria

Verbund sees finale to EA merger

Hans Haider, the chairman of Austria's leading power supplier, Verbund, has weeks to go before realising a project that he has promoted for years — the merger of Verbund with regional suppliers to create a firm that will compete with Europe's largest utilities. Verbund shareholders are expected to approve the new firm, Energy Austria (EA), next month. Haider says the merger partners are doing what they can to ensure that EA is operating by 1 October. He expects the savings from the integration of the partners' trading and wholesale operations to reach €40mn/yr, of which €8mn-10mn could be seen by the end of this year. This will help defray the investments that Verbund expects to make acquiring and building new generation and upgrading transmission lines. The utility will decide this autumn on whether to invest €70mn-80mn to add up to 140MW of capacity at its 65.2MW Gerlos hydroelectric plant and to build an 800MW gas-fired plant in the Styria region. A deal to purchase the non-nuclear generating assets of Slovenia's Slovenske Elektrarne is pending. And Italian firm Energia, a joint venture between Verbund and the DeBenedetti Group, plans to build three 760MW gas-fired plants by 2007. One is already under construction.

Czech Republic

CEPS tender attracts no interest

Dominant Czech utility CEZ is negotiating the sale of its remaining 34pc stake in grid operator CEPS with the finance ministry after a tender to sell the shares failed to attract investors. Initial estimates set the value of the shares at around 6.5bn koruna (€207mn). CEZ was required to sell its ownership of the grid operator as a condition of buying shares in all eight Czech electricity distributors (*APE, 3 April 2003, p5*). CEZ chairman Martin Roman plans to extend the utility's aggressive policy of generation and distribution asset acquisition in southeast Europe to position CEZ as one of Europe's leading utilities ahead of a further part-privatisation loosely scheduled for 2006. The Czech state owns 68pc of CEZ, with the rest belonging to financial and independent investors. Roman says he expects to bid for conventional thermal power plants in Bulgaria and Poland. Bulgaria expects to complete the sale of three coal-fired power stations during the first half of 2005. CEZ is also participating in the privatisation of power plants in Slovakia and Romania. The utility reported first-half profits of Kc3.9bn, a 68pc decrease from the same time last year, although profits in the first half of last year were boosted by the sale of a 66pc stake in CEPS. Power sales rose from Kc26.6bn in 2003 to Kc31.1bn this year. Domestic sales rose by 3.5pc to 28.8TWh, with CEZ increasing its share of the domestic market by 5pc to 73pc. The company generated 42.4TWh of power in the first half of this year, 2.1pc more than during the same period last year.

Germany

Trianel steps closer to CCGT decision

Municipal utility Trianel's plans to construct an 800MW combined-cycle gas turbine (CCGT) power plant have advanced with the formation of an eight-member consortium to develop the project. Trianel Power Projektentwicklung (TPPE) will now work on site selection, securing planning permission and a gas supply contract before making the final decision on construction. The other members of TPPE are local utilities EWMR, Stawag Energie, EHW, Enwor, Stadtwerke Osnabruck, SWK Energie and Teutoburger Energienetzwerk. About 1GW of gas-fired combined heat and power (CHP) plant will come on line in Germany this year as municipal utilities look to benefit from legislation that grants higher prices to CHP-generated power so long as the plant is brought on line by 31 December 2005. Additional CCGT plant could be built in Germany, as the European Commission appears set to abolish

EdP announces image makeover

Electricidade de Portugal (EdP) has changed its name to Energias de Portugal to rebrand itself before competing in the Iberian power market, Mibel.

The utility, Portugal's largest electricity company, has also swapped its old power turbine logo for a white smile drawn against a sharp red background. Communications director Horacio Periquito says EdP wants to sell itself as a modern firm that relates to consumers, not a "simple industrial generator". This follows a retooled business philosophy calling for "simplicity, proximity, comfort, innovation and social responsibility".

EdP has timed its makeover to prepare for competition in the Iberian energy market, which with 50mn consumers will be Europe's fourth-largest. Portuguese companies can operate in Spain's electricity spot market now, but the creation of an official Iberian spot market, and the launch of a new futures market, is stalled pending new legislation (*APE, 29 July, p6*).

EdP has also announced that it will increase its stake in Spanish utility Hidrocantabrico from 39.5pc to 95.7pc, paying €1.2bn for German utility EnBW's 34.6pc stake and smaller holdings held by other investors. The transaction will transform EdP into the Iberian peninsula's third-largest power group after Spain's Iberdrola and Endesa. EdP says the deal had a "strong and compelling transaction rationale" and that it will bring synergies of €25mn-35mn by 2007 through the integration of Hidrocantabrico's business sectors.

EdP and Hidrocantabrico have a combined share of the Iberian electricity and gas markets of 21pc and 19pc respectively, according to energy analyst Miguel Viana of Lisbon-based brokerage Espirito Santo. EdP's goal will be to preserve Hidrocantabrico's market position and increase its presence in gas procurement, Santo says.

taxes on imports of natural gas, paving the way for a "dash for gas" to fuel new power plants.

Goldman Sachs offers EEX clearing

Goldman Sachs has become the eighth bank to offer clearing services on Germany's power exchange, EEX. Clearing members function as credit and risk guarantors, eliminating counterparty and price risk and removing the need for lengthy cross-party financial checks. EEX's services are available to participants trading futures on the exchange, or over-the-counter transactions. Goldman Sachs' trading division, J Aron, began trading on the EEX spot market in June. The seven existing EEX clearing members are Bayerische Landesbank, Calyon Financial, Credit Suisse, Deutsche Bank, ING BHF-Bank, Nordea Bank and UBS.

Italy

Hera and Agea to merge

The boards of directors of Bologna-based multi-utility Hera and Ferrara-based utility Agea have agreed to merge. Hera paid €55mn for a 49pc stake in Agea last October and plans to increase this to 100pc by the end of this year. Hera will issue nearly 47mn shares to fund the purchase of the remaining shares in Agea and a 24.5pc share in water supplier Acosea. The merger will boost Hera's position in the northern region of Emilia Romagna, particularly in the geothermal and district heating sectors. The merger is expected to be completed by the end of this year, subject to shareholder approval. There are unconfirmed reports that Hera chief executive Stefano Aldovrandi may be replaced by chairman Tomaso Tommasi di Vignano following recent elections in which union leader Sergio Cofferati was elected mayor of Bologna, which owns 19.6pc of the utility.

Ergon Energia increases sales

Ergon Energia, an energy trading company set up last November by Italian multi-utility ASM Brescia and Spain's Endesa, sold 2.9TWh to 700 customers in the fiscal year ending 30 June. The company closed the year with turnover of €117mn and profit of €413,000. ASM Brescia and Endesa each own 50pc of the company, which supplies electricity, gas and power to the liberalised market. Ergon's goal is to capture 10pc of the electricity market by 2009 and to have revenues of €1.1mn. Ergon Energia sells the 18,000GWh generated by Endesa Italia's plants.

Sardinian council blocks wind farms

Sardinia's regional council has revoked a tender for construction of 900MW of new wind parks and postponed for six months a review of requests to build additional plants. The measures were announced during the election campaign of the region's newly elected president, Renato Soru, and represent a change from the previous administration's policy. Announced in June, the tender had a September deadline. Dominant utility Enel, which had one of its wind projects in the Nuoro area rejected, says it is not changing its plans. The utility has asked the council to set up a meeting during which it can justify the need for wind generation in the region. Enel operates 14 wind plants in Italy with total capacity of about 200MW. Italy's renewable energy association says it will co-ordinate requests from energy producers that want to file a petition against the council's measures.

New transmission link approved

Grid operator GRTN has been given approval to build a new power line in the south that will cut through network congestion and increase imports along the Italy-Greece interconnector. Construction on the Matera-Napoli-Santa Sofia line is expected to begin in the next month and to be completed within nine months, GRTN says. The line will allow imports along the Greek line, which was opened in 2002, to reach its full 500MW capacity. Imports have been restricted to around 150MW because of congestion, and power plants in the Puglia region have been forced to restrict generation because the grid cannot handle their full output. There is a sense of urgency to the construction, as Italy's available capacity of around 50,000MW is being tested by peak demand surges — which have reached record highs of 53,500MW — leaving the country even more dependent on imports. Local authorities have been blamed by the government for opposing the unblock plants decree of 2002, which is designed to streamline the approval process for new plants.

Court to hear appeal in AEM case

Italy's administrative appeal court will hear an appeal this month from Milan's local council. The council is appealing a June decision by an administrative court in Lombardy concerning corporate governance at municipal utility AEM. The ruling has blocked the council's attempts to sell a 17.6pc stake in the utility. At issue is a law passed by the Milan council in April giving itself the right to retain control over AEM's board of directors despite the fact that the share sale would reduce its ownership from 51pc to 33.4pc. Consumer associations had challenged the ruling.

Netherlands

Amsterdam grid capacity to double

Dutch grid operator Tennet will boost capacity of the high-voltage grid in the western Netherlands from 150kV to 380kV using proceeds from its monthly interconnector auctions. The growth is essential due to rising demand in the area, according to energy regulator DTe, which says the work will take two years at an estimated cost of €44mn. Tennet manages the Netherlands' 3,500MW import-export capacity and auctions access to the German and Belgian interconnectors every month. DTe says the upgrade of the Randstad grid will bring supply security to the region.

Norway

Oslo mulls increased gas use

The Norwegian government wants to encourage more domestic use of natural gas, according to a discussion paper submitted to parliament on 6 August. The paper proposes building more gas-fired power plants to reduce the country's

near-total reliance on hydroelectric power. Some firms, including Statoil, have begun exploring this, although environmental groups oppose building gas-fired power plants. The government has also proposed forming a joint market with Sweden to trade green certificates. The paper says a gas pipeline network could be built when domestic demand rises. The government's preferred option is to ship liquefied natural gas (LNG) along coastal routes, rather than building an inland pipeline transmission network, on the grounds of cost and the absence of a developed domestic market. Norway's parliament will now debate the position paper. There is no timetable for potential legislation, beyond a date set for next May for a potential bill to set up a green certificate market.

Joint market with Sweden proposed

The Norwegian government is proposing the development of a joint market with Sweden for trading green energy certificates. Norway is aiming to pass a new law next year making the green certificate market compulsory for renewable energy, so that trading in a communal market with Sweden can start from January 2006. Sweden launched its green certificate market last year. Norway has been planning a similar scheme for some time. "This will be an important part of strengthening the government's commitment to renewable electricity," says Norwegian oil and energy minister Thorhild Widvey. The project will require a great deal of preparation and co-operation on behalf of the participants, according to Knut Stromnes, the head of green certificates trading at the Nordic power exchange NordPool. Only some of the trading in green certificates is transacted over the NordPool exchange, but with Norway as an active participant in the market, this liquidity would rise.

Spain

World's first commercial wave farm

Iberdrola has agreed to build the world's first commercial wave farm off Spain's north coast. The project will convert wave energy to electricity and feed 1.25-2MW to the grid. Construction will begin next year, according to the utility, which says it plans to install 100MW of wave farms along the Cantabrian coast. The plant will be built by US-based Ocean Power Technologies (OPT), which will retain a 10pc share. Iberdrola will own 70pc of the project, with the remainder divided equally between Cantabria's development agency and Spain's energy agency. OPT's so-called powerbuoy technology uses ocean oscillations to drive a submerged piston that powers a hydraulic motor on the sea bed. A 1MW pilot project off the coast of Hawaii is supplying power to a US naval base, OPT says, but the Iberdrola project is different because the electricity will be fed directly to the grid, using the same type of transformers that Iberdrola's wind farms use. OPT claims that wave energy has a productivity rate of 80-90pc, equivalent to fossil fuel technologies, as even small water movements are sufficient to generate electricity. This contrasts with 20-30pc from wind farms. Iberdrola is one of the world's largest renewable power companies. In July, the utility pledged €3.1bn to increase its renewables capacity from 2,664MW to 4,500MW by 2008.

Union Fenosa withdraws appeal

Union Fenosa has withdrawn its appeal against a government decision to close the 153MW Jose Cabrera 1 nuclear plant. The unit was commissioned in 1969 and is Spain's first and smallest reactor. It was scheduled for shutdown in 2009, but a September 2002 review by nuclear regulator CSN recommended that the plant be shut down in April 2006 because of safety concerns. The review was part of CSN's procedure for approving a three-year extension of the plant's operating licence. Union Fenosa says it withdrew the appeal because it believed the court would rule that the government has the right to decide when the reactor should close and that a protracted battle could tarnish the utility's image. The loss of Cabrera's generation will have little impact on Union Fenosa's generating capacity as it plans to bring 2,400MW of combined-cycle gas turbine generating capacity on line by 2007.

Gas Natural starts third CCGT plant

Spain's largest gas firm, Gas Natural, has begun operating a third gas-fired power station. The 400MW plant in Arrubal, in Rioja, was built for €360mn and will soon be followed by the start-up of another 400MW combined-cycle gas turbine (CCGT) plant in the same area. The company plans to have 4,800MW of gas-fired capacity operating by the end of 2008, and is building a 1,200MW CCGT in Cartagena to help meet this target.

UK

IP to get UK hydro assets by year end

UK generator International Power (IP) hopes to complete the acquisition of US-based Edison Mission Energy's (EME) UK assets by the end of the year, after which it intends to take over the trading activities and management of the plants. IP acquired 13 plants worldwide from EME in a deal worth $2.2bn last month. The deal included the UK's 1,728MW Dinorwig and 360MW Ffestiniog hydroelectric assets, and its one-third share in the 214MW Derwent combined-cycle gas turbine plant. The hydroelectric pumped storage station assets are important to the UK power market, as they provide flexible capacity with a rapid start-up time, as well as being able to soak up additional capacity. But EME said previously that it would review operation of the assets, as difficult market conditions have limited their profitability.

BE hails end of cheap energy

British Energy (BE) struck a cautiously optimistic note at its annual general meeting on 5 August, with company chairman Adrian Montague saying the nuclear generator is well placed to benefit from higher power prices and the end of an era of low energy prices. "There seems little doubt that prices have turned… as the market moves to a period of structurally higher prices," Montague said. Negotiations between

the UK government and the European Commission over BE's restructuring plan are progressing. Montague reacted to shareholder criticism that the deal struck with the government in October 2003 failed to reflect the bounce in power prices this year, saying there were no other options at the time the agreements were signed.

Ofgem reveals renewables shortfall

UK energy regulator Ofgem says the bankruptcy of UK supply firm Atlantic Energy will leave a shortfall of nearly £8.4mn (€12.6mn) in the renewables obligation (RO) buy-out fund for the April 2003-04 period. Atlantic's administrative receivers KPMG estimated the figure, which is close to the original forecasts made this June, while the estimated shortfall for the April 2004-March 2005 period has been reduced to £679,000 from £721,000. Atlantic went into administration in April this year. Maverick Energy, which went into receivership in June 2003, will leave a shortfall of £644,000 to the buy-out fund for the April 2003-04 period. KPMG says neither company has the funds to meet these obligations, leading Ofgem to state that both are liable to fines or enforcement actions to recover the shortfall. But this may be a hollow threat as Ofgem has already decided to take no action against TXU, whose bankruptcy left a £22mn hole in the RO fund. The problem of how to recover money from bankrupt companies is being negotiated between Ofgem and the Department of Trade and Industry. The news will be bearish for the UK Rocs market, as a weaker buy-out fund will provide less of an incentive for supply companies to meet their obligations through the acquisition of Rocs. Those on the generator side argue that prices will not rise until more participants join the scheme, and that confidence remains low after TXU left the market. Rocs prices for compliance period three stood at a stable £43-45/MWh at the start of month.

Government discusses fossil strategy

The UK government is pledging to work harder in reducing carbon dioxide (CO_2) emissions from fossil fuels to plug the gap left by the renewables sector. The Department of Trade and Industry (DTI) will actively promote carbon abatement technology, with a particular emphasis on large combustion power plants, to help meet the target of a 60pc reduction in CO_2 emissions by 2050, as set out in last year's energy white paper policy document. DTI says it will also tackle the market and regulatory factors that stand in the way of new technologies. Nuclear power is being considered along with renewable technologies to tackle long-term climate change goals, even though the white paper stopped short of committing to new nuclear plants in the UK. One of the suggested technologies is so-called carbon sequestration, where CO_2 is separated during the process of burning fossil fuels for power generation, then buried underground. The report suggests that development of carbon-reduction projects be started now, given the 10 to 15-year lead time, even though market signals are weak.

Renewable policy changes considered

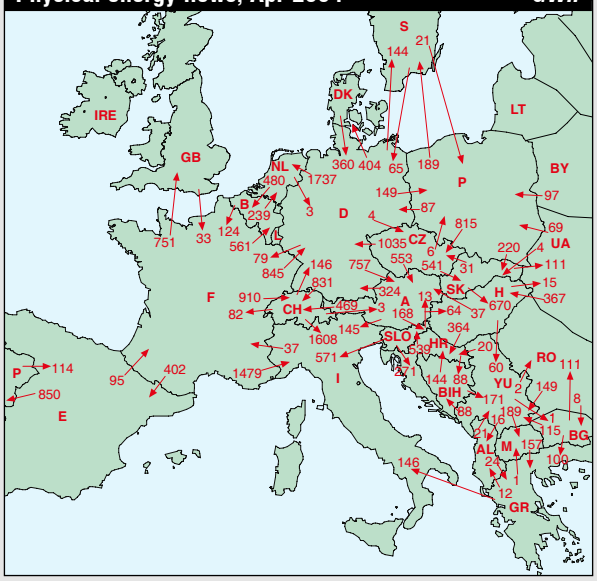
The UK government has set out the terms of reference for a review of the renewables obligation (RO) that provides generators with incentives to increase output from green sources. The review, due out in December next year, follows a study from the House of Lords that casts doubt on the government's targets for renewable generation. The RO will remain in place until 2027, but will be amended if it helps the government meet its target of having renewables provide 10pc of total generation by 2010 and 20pc by 2020. These targets will remain in place, as will the RO certificates (Rocs) scheme that allows generators to trade allowances. Industry has called for the Rocs scheme to be extended to heat generated by combined heat and power plants. The government plans to issue a separate report on this issue, considering such things as the impact of the EU emissions trading scheme on UK power prices, and whether a combined Roc buy-out fund should be created when Scotland is brought under the UK's energy trading regulations next April.

Balkans

Grid access fees harmonised with EU

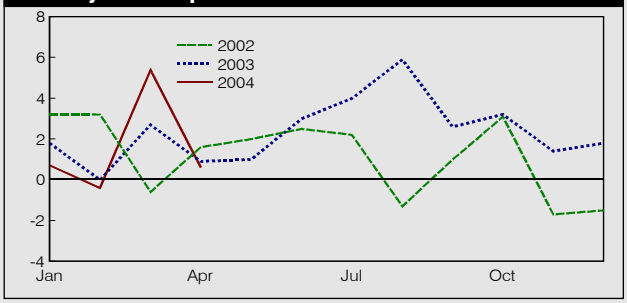
Six southeast European countries are one step closer to joining the pan-European transmission network after agreeing to a new cross-border grid access tariff (CBT) mechanism that mimics the EU system already in place. Albania, Bosnia-Herzegovina, Bulgaria, Macedonia, Romania and Serbia signed an agreement harmonising grid-access tariffs across the region and abolishes border fees and other irregular charges relating to electricity transmission. The agreement is designed to facilitate and encourage the development of competitive power markets in the region, with the objective of preparing southeast Europe's grid for integration with the rest of Europe. The new arrangement is retroactive to 1 July, though no uniform solution has been agreed for dealing with transmission losses. A standard injection fee of €1/MWh for imports into the region has been instituted, which will help make up for the earnings lost by the abolition of local import tariff charges. Greece, Ukraine, Hungary and Turkey all export power to southeast Europe. But Croatia — the only mainland European country west of the former Soviet Union that does not participate in a CBT agreement — can neither join the southeastern group nor export to it, as its connections to the area were cut in the Yugoslav civil wars of the 'nineties.

Physical energy flows, Apr 2004 — GWh



Consumption rose to 188.74TWh in April, up by 0.6pc from the same period last year, according to the Union for the Co-ordination of Transmission of Electricity (UCTE). But this represented a month-on-month fall of 26.64TWh. Production stood at 193.11TWh, down from 218.27TWh in March. Total physical energy flows of 23.58TWh were down from 25.29TWh in March. France's Argenteuil substation was down during the month, with 40MW lost for less than one hour.

Monthly consumption variation — %



Load on 3rd Wed — *Consumption loads in MW*

Peak load													
21 April 2004	B	D	E	F	GR	I	SLO	HR	YU	L	NL	P	†UCTE
	11,366	67,800	31,178	60,334	6,696	45,896	1,727	2,104	5,391	823	12,835	6,528	306,971
% change*	4,3	1,3	13,0	3,4	-2,1	-0,8	2,1	2,7	5,2	-0,8	0,3	9,4	1,4
Power produced in parallel operation (including autoproduction)													
21 April 2004	B	D	E	F	GR	I	SLO	HR	YU	L	NL	P	†UCTE
	9,955	73,500	31,178	66,502	6,044	39,025	2,103	1,890	4,635	762	10,011	4,933	313,791

**change from the same period in the previous year †includes countries not shown in table*

April 04 physical energy flows (on the >/- 110 kV transmission lines) — GWh

	Importing country																		
	B	D	E	F	GR	I	SLO	HR	BIH	FYROM	YU	L	NL	A	P	CH	Centrel	3rd countries	Total export
Exporting country																			
B - Belgium	-	-	-	124	-	-	-	-	-	-	-	122	239	-	-	-	0	-	485
D - Germany	-	-	-	79	-	-	-	-	-	-	-	398	1737	757	-	831	153	548	4,503
E - Spain	-	-	-	95	-	-	-	-	-	-	-	-	-	-	850	-	0	169	1,114
F - France	561	845	402	-	-	1479	-	-	-	-	-	-	-	-	-	910	0	751	4,948
GR - Greece	-	-	-	-	-	146	-	-	-	1	-	-	-	-	-	-	0	12	159
I - Italy	-	-	-	37	0	-	0	-	-	-	-	-	-	0	-	0	0	-	37
SLO - Slovenia	-	-	-	-	-	571	-	271	-	-	-	-	-	13	-	-	0	-	855
HR - Croatia	-	-	-	-	-	-	539	-	88	-	0	-	-	-	-	-	0	-	627
BiH - Bosnia	-	-	-	-	-	-	-	144	-	-	171	-	-	-	-	-	0	-	315
FYROM - Macedonia	-	-	-	-	157	-	-	-	-	-	0	-	-	-	-	-	0	-	157
SCG - Yugoslavia	-	-	-	-	-	-	-	20	88	189	-	-	-	-	-	-	4	16	317
L - Luxemburg	195	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	259
NL - Netherlands	480	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	483
A - Austria	-	324	-	-	-	145	168	-	-	-	-	-	-	-	-	469	64	-	1,170
P - Portugal	-	-	114	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	114
CH - Switzerland	-	146	-	82	-	1608	-	-	-	-	-	-	-	3	-	-	0	-	1,839
Centrel	0	1,122	0	0	100	0	0	364	0	0	258	0	0	570	0	0	2,402	300	5,116
III1	-	425	0	33	24	-	-	-	-	-	24	-	-	-	-	-	583	-	1,089
Import	**1,236**	**2,929**	**516**	**450**	**281**	**3,949**	**707**	**799**	**176**	**190**	**453**	**520**	**1976**	**1343**	**850**	**2,210**	**3,206**	**1,796**	**23,587**

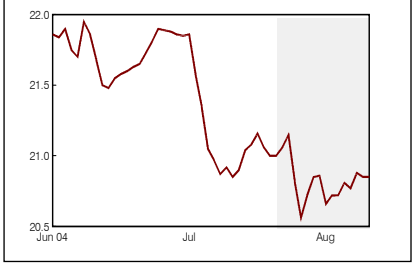
A "0" in a column indicates there is a transmission line between the two countries, but that no power was exchanged for the reporting period.

***Centrel** = Bulgaria, Czech Republic, Hungary, Poland, Romania, Slovak Republic*
***Third countries** = Albania, Belarus, Denmark, Great Britain, Morocco, Moldova, Sweden, Turkey, west Ukraine*

Gas: prompt gas at three-month high

Prompt NBP gas rose to three-month highs on uncertainty about August North Sea maintenance programmes. Despite warm weather pushing demand to 2004 lows, day-ahead UK gas traded above 22p/th for the first time since May. The loss of the Loggs pipeline system to maintenance, and slightly reduced flows to St Fergus and Teesside, has left the market anxious about supply margins. Forward gas made gains, and markets that are pricing off record crude oil futures notched contract highs, pushing the market into contango. Winter 2005-06, which rose to contract highs at 37.45p/th, moved to assert a premium over winter 2004-05 that widened out to 1.2p/th. And summer 2005 reached a contract high at 25.75p/th.

IPE September natural gas *p/th*

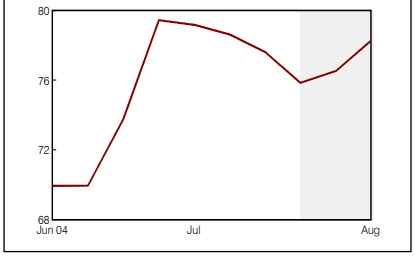


Shaded area on graphs refers to the last two weeks trading covered in the market commentary

Coal: freight lifts cif ARA prices

The prompt European delivered steam coal index rose by over $1.70/t amid a hike in spot route-4 freight rates, rising demand from European consumers and signs that supplies of cheaper Russian coal may be dwindling. Cape-size freight rates stand at $18.75/t, up by $1.80/t on the same period a month ago. Traders expect spot rates to dip in the short term, in line with an anticipated market correction. Supplies of Russian coal for delivery in the next 90 days are drying up as utilities hoover up remaining prompt availability. Russian producers were heard offering material for October-December delivery at $65-65.50/t fob Baltic. Freight is $12.50/t for the Baltic to ARA, giving a delivered price of around $78.50/t cif ARA.

TFS API2 weekly prices *$/t*

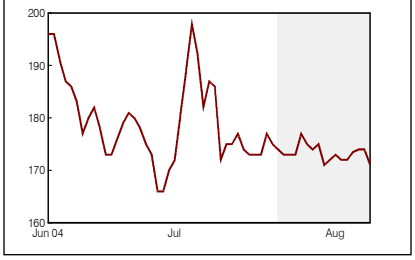


Shaded area on graphs refers to the last two weeks trading covered in the market commentary

Fuel oil: crude hits record highs

Crude oil price rises have been relentless in the last two weeks, hitting fresh records almost daily. Uncertainty that Opec can squeeze out sufficient spare capacity to meet strong demand and fears that the Yukos bankruptcy could interrupt Russian supply drove the markets. But gains for fuel oil have been far more modest and the product is in global surplus. There has been particularly poor demand for low-sulphur grades used for power generation, which have been uncompetitive against alternative fuels such as gas and coal. Prices have even fallen below high-sulphur grades, which is highly unusual. Fuel oil looks likely to be oversupplied as long as refiners are running close to full capacity to meet demand for gasoline and heating oil.

Low-sulphur fuel oil cif NWE *$/t*



UK and Germany spark spreads for varying efficiencies in plant generation **10 Aug**

	Price	Fuel	Electricity month	Spark spread (£/MWh)		
UK base load		(£/MWh)	ahead base load	30pc	38pc	49.13pc
Month-Ahead gas, NBP (p/therm)	20.85	7.11	22.40	-1.29	3.68	8.17
Coal, ARA ($/t)	78.70	6.13	22.40	1.99	6.27	10.14
Fuel oil, 1% cif UK, 1% ($/t)	171.00	7.76	22.40	-3.45	1.97	6.87
	Price	Fuel	Electricity month	Spark spread (€/MWh)		
Germany base load		(€/MWh)	ahead base load	30pc	38pc	49.13pc
Month-Ahead gas, Bunde (€/MWh)	11.45	11.45	32.63	-5.50	2.49	9.73
Coal, ARA ($/t)	78.70	9.19	32.63	2.02	8.44	14.24
Fuel oil fob ARA, 1% ($/t)	163.00	11.09	32.63	-4.32	3.43	10.44
Germany peak load			peak load			
Month-Ahead gas, Bunde (€/MWh)	13.33	13.33	45.30	0.91	10.22	18.64
Coal, ARA ($/t)	78.70	9.19	45.30	14.70	21.11	26.92
Fuel oil fob ARA, 1% ($/t)	163.00	11.09	45.30	8.36	16.10	23.11

Spark spreads compare the cost of generating power at various heating efficiencies with the cost of buying power from the grid. A positive spread indicates it is economical to buy fuel, while a negative spread indicates it is economical to buy power off the grid. Fuel and electricity prices are taken from the Argus European Electricity, Argus European Natural Gas, Argus Coal Daily International and Argus European Products daily market reports. The model does not take into account local taxes or transport costs.

Part 1 of 1

The Argus power plant database includes information on conventional generating plant with a nominal installed capacity of 1MW. Renewable plants are included when capacities and owners/operators are known. Preference in all cases is given for plant connected to the grid. The table to the right gives Ireland's overall installed generation capacity.

Total Irish capacity by type	Total size *MW*	Number of plants
Hydro	655	34
Renewables	1,945	100
Thermal	6,897	36
Unspecified	3	1

Plant name	Size *MW*	Status	Owners	Operators	Fuel
A&L Goodbody	1.0	Operating	BG Cogen	BG Cogen	Gas
Aghada	525.0	Operating	ESB	ESB	Gas
Aghada Gas	270.0	Operating	ESB	ESB	Gas
Anarget	2.0	Operating	Saporito		Wind
Ardnacrusha	85.0	Operating	ESB	ESB	Hydro
Arklow Banks	25.2	Operating	Airtricity		Wind
			EHN		Wind
Balleally Landfill site	5.0	Operating	Wimpey EPC	Irish Power Systems	Waste
Ballylogan Landfill	2.0	Operating	Irish Power Systems	Irish Power Systems	Waste
Ballyraggert Glanbia	2.5	Operating	Glanbia	Ballyraggert Power	Gas
Barnesmore	15.0	Operating	Scottish Power	B9 Energy	Wind
Beal Hill	2.6	Operating	First Electric		Wind
Beenageeha	3.8	Operating	B9 Energy	B9 Energy	Wind
Bellacorick	40.0	Operating	ESB	ESB	Peat
Bellacorick	6.45	Operating	Renewable Energy Ireland		Wind
Black Banks	3.4	Operating	DP Energy		Wind
Cahirciveen	5.0	Operating	ESB		Peat
Carbery	5.0	Operating	CM Power	CM Power	Gas
Cark	15.0	Operating	B9 Energy Services	B9 Energy Services	Wind
			Renewable Energy Systems		
Carnsore Point	12.0	Operating	Hibernian Wind Power		Wind
Carrigadrohid	8.0	Operating	ESB		Hydro
Cathleen's Fall	45.0	Operating	ESB		Hydro
Clady	4.0	Operating	ESB	ESB	Hydro
Cliff	20.0	Operating	ESB		Hydro
Corneen	3.0	Operating	Airtricity	Airtricity	Wind
Corneen	6.5	Operating	Ganderoy		Wind
Cory Mountain	4.8	Operating	Moneenatieve	Moneenatieve	Wind
Crockahenny	5.0	Operating	ESB	Hibernian Wind Power	Wind
Cronlaght	5.0	Operating	Gineadeoiri Gaoithe Teo	Airtricity	Wind
Cuillaigh	11.9	Operating	Airtricity	Airtricity	Wind
Cuklow Bank	25.2	Operating	Airtricity	Airtricity	Wind
Currabwee	4.8	Operating	Patrick & John Kingston		Wind
Curramore	0.8	Operating	ESB		Hydro
Dairygold Co-op	10.0	Operating	CHP		Gas
Drumlough Hill	4.8	Operating	Baylsham	Baylsham	Wind
Dublin Bay Ringsend	400.0	Operating	Synergen		Gas
Dublin Corp.	1.0	Operating	BG Cogen	BG Cogen	Gas
Dungarvan Glanbia Creamery	110.0	Operating	Dungarvan Energy		Gas
Dunsink	4.8	Operating	Irish Power Systems	Irish Power Systems	Waste
Edenderry	117.0	Operating	Edenderry Power	Fortum	Peat
Erne	65.0	Operating	ESB	ESB	Hydro
Friarstown	1.0	Operating	Irish Power Systems	Irish Power Systems	Waste
Golden Falls	4.0	Operating	ESB		Hydro
Golden Vale	5.2	Operating	GV Power		Gas
Great Island	240.0	Operating	ESB	ESB	Oil
Guinness Brewery, St James Gate	15.0	Operating	Gatepower		Gas
Huntstown	343.0	Operating	Viridian		Gas
Inniscarra	19.0	Operating	ESB		Hydro
Inis Meain	0.7	Operating	Fuinneamh Glas Teo		Wind
Kilronan	5.0	Operating	South Western Farm Services		Wind
Kingsmountain	25.0	Operating	Airtricity	Airtricity	Wind
Lakelands Dairy	1.5	Operating	BG Cogen	BG Cogen	Gas
Lanesboro	85.0	Operating	ESB	ESB	Peat
Largan Hill	4.8	Operating	Airogen		Wind
Lee	29.0	Operating	ESB	ESB	Hydro
Leixlip	4.0	Operating	ESB		Hydro
Lenanavea	2.0	Operating	Western Prospect		Wind
Liffey	38.0	Operating	ESB	ESB	Hydro

Statistics

Plant name	Size *MW*	Status	Owners	Operators	Fuels
Lowerymore	0.6	Operating	Hibernian Hydro		Hydro
Marina	115.0	Operating	ESB	ESB	Gas
Milane Hill	7.5	Operating	Renewable Energy Systems		Wind
Millipore, Carrigtowhill	1.0	Operating	BG Cogen	BG Cogen	Gas
Moneypoint	915.0	Operating	ESB	ESB	Coal
North Wall	266.0	Operating	ESB	ESB	Gas
					Oil
Poolbeg	1,020.0	Operating	ESB	ESB	Gas
					Oil
Poolbeg CCGT	470.0	Operating	ESB	ESB	Gas
Poulaphouca	30.0	Operating	ESB		Hydro
Shannonbridge	125.0	Operating	ESB	ESB	Peat
Slieve Rushen	3.0	Operating	Sean Quinn Group	B9 Energy	Wind
Spion Kop	1.2	Operating			Wind
Tarbert	620.0	Operating	ESB	ESB	Oil
Tranmore Valley Landfill	2.0	Operating	Irish Power Systems	Irish Power Systems	Waste
Turlough Hill	292.0	Operating	ESB	ESB	Hydro
Tursillagh	15.0	Operating	PowerGen		Wind
			Saorgus		
Tullymarry	4.8	Operating	Eco Wind Power		Wind
Virginia Glanbia	6.6	Operating	Glanbia Ingredients		Gas
Wallingstown	2.0	Operating	BG Cogen	BG Cogen	Gas
Waterford Crystal	2.1	Operating	Waterford Crystal	Ballyraggert Power	Gas
Androssan	288.0	Under construction	Airtricity	Airtricity	Wind
Arklow Banks	25.2	Under construction	Airtricity		Wind
Barnes Bridge	0.5	Under construction	Hibernian Hydro		Hydro
Derrclogher	0.4	Under construction	Hibernian Hydro		Hydro
Derrybrien	60.0	Under construction	PowerGen		Wind
			Saorgus		
Doorian	0.3	Under construction	Hibernian Hydro		Hydro
Inchinanagh	0.5	Under construction	Hibernian Hydro		Hydro
Kings Mountain	25.0	Under construction	Airtricity	Airtricity	Wind
Lough Ree	91.0	Under construction	ESB		Peat
Meentycat	72.4	Under Construction	Meentycat	Airtricity	Wind
Snugborough	13.5	Under construction	Quinn Wind Holdings	Airtricity	Wind
Tappaghan	19.5	Under construction	Airtricity	Airtricity	Wind
West Offaly	137.0	Under construction	ESB		Peat
Abbeyfeale	0.2	Planning	Martin J Leahy		Hydro
Arigna	7.7	Planning	Arigna Fuels		Wind
			Gaoithe Saor Teo		
Arthurstown	3.8	Planning	Irish Power Systems	Irish Power Systems	Waste
Athea Upper & Gortnagross	16.0	Planning	Tradewinds Energy		Wind
Aughinish	150.0	Planning	Aughinish Alumina		Gas
			Eon Benelux		
Balieborough	6.3	Planning	DeWind Ireland		Wind
			Gartnaneane		
Ballinveny	6.0	Planning	Alpha Wind Energy		Wind
Ballystrang	7.8	Planning	Airtricity		Wind
			Redwind Energy		
			Saporito		
Bellacorick 3	2.6	Planning	Compower		Wind
Bere Island	0.6	Planning	The Bere Island Projects Group		Wind
Burtonport	0.7	Planning	Cumhacht Comharcumman Teoranta		
Wind					
Cark Extension	3.5	Planning	Airtricity		Wind
Carrane	3.4	Planning	Orliven		Wind
Carrane	4.5	Planning	Natural Environmental Technology		Wind
Carrane	5.1	Planning	Hermosa		Wind
Carrig	6.0	Planning	Carrig Wind Farm		Wind
Carrig	3.0	Planning	Alpha Wind Energy		Wind
Clare	19.5	Planning	Booltiagh Wind		Wind
Cloghboola	45.0	Planning	Saorgus		Wind
Coomatallin	6.0	Planning	Dustmount	Airtricity	Wind
Cordal	53.3	Planning	Saorgus		Wind
Corr na Mona	7.7	Planning	Corr na Gaoithe Teo		Wind

Statistics

Plant name	Size *MW*	Status	Owners	Operators	Fuels
County Hall	1.0	Planning	Meath County Council		Biomass
Damastown	400.0	Planning	Babcock & Brown		Gas
Dooleeg More	2.0	Planning	Mr. Michael Moyles	Alpha Wind	Wind
Drumardagh	0.4	Planning	William Holmes		Hydro
EPC Gartnaneane	13.5	Planning	Gartnaneane	Airtricity	Wind
Esk	10.0	Planning	Robert Lyons	Alpha Wind	Wind
Gartnaneane	121.5	Planning	Airtricity	Airtricity	Wind
Greater Gabbard	500	Planning	Airtricity	Airtricity	Wind
Inis Meain	0.7	Planning	Fuinneamh Glas Teo		Wind
Inverin	2.8	Planning	Fuinneamh Gaoithe Teo		Wind
Keelderry	48.0	Planning	Keelderry Windfarm		Wind
Lee Road Waterworks	3.0	Planning	Waterpower Engineering		Hydro
Lough Guitane Waterworks	0.2	Planning	Kerry County Council		Hydro
Meenalaban	22.5	Planning	Airtricity		Wind
Pluckanes West	2.0	Planning	Mr. Conor O Leary	Alpha Wind	Wind
Raheen Barr, Claggan and Derrynadivva	18.7	Planning	Ecopower		Wind
Ratrussen	70.0	Planning	Airtricity		Wind
Richfield/Bindoo	20.3	Planning	Airtricity		Wind
Scariff	3.3	Planning	Finsa Forest Products		Unspecified
Skehanagh	5.0	Planning	Alpha Wind Energy		Wind
Sologhead House	0.7	Planning	Sologhead House		Wind
Spawell Road	1.0	Planning	Wexford County Council		Biomass
Tarbert	28.5	Planning	Airtricity		Wind
Tarmonbarry	0.4	Planning	Camlin Electric		Hydro
Teevurcher	7.5	Planning	Airtricity		Wind
Tournafulla	7.6	Planning	Trencove	Airtricity	Wind
Tursillagh 2	6.8	Planning	Saorgus	Tursillagh Windfarms	Wind
Ballintra	0.4	Proposed	Mr William Holmes		Hydro
Ballyguyroe	7.0	Proposed	ERI (Ireland)		Waste
Barnesmore	0.5	Proposed	Ingleby		Hydro
Barrboy	7.9	Proposed	Innis Glas Energy		Wind
Bellacorick 2	320.0	Proposed	Bord na Mona	ESB	Wind
			ESB		
Blackwater 1		Proposed	Harland & Wolff Licences		Wind
Blackwater 2		Proposed	Wind Farm Developments		Wind
Borlin, Derryclogher, Bantry	0.4	Proposed	Ingleby		Hydro
Cappawhite	20.0	Proposed	Aeolus Energy		Wind
			DP Energy		
Carrane	4.0	Proposed	Waterfern		Wind
Carrhue		Proposed			Wind
Carrowmore	6.4	Proposed	Conor Ronan		Wind
Clogher Head	0.0	Proposed	Airtricity	Airtricity	Wind
Codling		Proposed	Harland & Wolff Licences		Wind
Coomleigh	15.0	Proposed	EF Energy		Wind
Currachill	6.0	Proposed	EF Energy		Wind
Devlin	0.6	Proposed	Ingleby		Hydro
Glenade	0.1	Proposed	Leitrim Co. Council		Hydro
Gneeves	15.0	Proposed	Gillian Kelly		Wind
Inchamore	15.0	Proposed	Treasury Estates		Wind
Inchinanagh, Kilgarran	0.5	Proposed	Ingleby		Hydro
Kish	250.0	Proposed	Kish Consortium		Wind
Lackagh , Drumlackagh	1.0	Proposed	Ingleby		Hydro
Meenachallow, Glenties	0.3	Proposed	Ingleby		Hydro
Meenadreen	4.8	Proposed	Whaplode		Wind
Meenadreen Laghey	13.0	Proposed			Wind
Moneypoint	22.5	Proposed	Hibernian Wind Power		Wind
			Pro Ventum Ingenieurburo fur Energie-Technik		
Mullen Hill	4.8	Proposed	Windmaster Developments		Wind
Owenaher , Tobercurry	0.3	Proposed	Ingleby		Hydro
Oweniny	7.0	Proposed	Irish Energy (Joint Venture)		Waste
Owenwee , Dunlewy, Dungloe	0.4	Proposed	Ingleby		Hydro
Tursillagh 3	6.8	Proposed	PowerGen	Tursillagh Windfarms	Wind
Ferbane	90.0	Shutdown	ESB		Peat
Rhode	40.0	Shutdown	ESB		Peat
Ringsend	270.0	Shutdown	ESB		Oil

UK

Summers re-evaluated on bullish coal

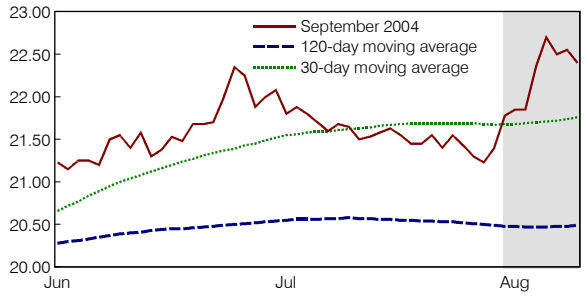
Winter-ahead prices remained largely stable during the period, defying strong gains on oil and coal, with this fuel risk premium now transferred to later curve contracts. Summer 2005 base-load prices exceeded record highs on 4 and 9 August by pushing above £26.40/MWh, slashing the summer/winter spread over the period by £0.50/MWh to £3.50/MWh.

Physical coal was the main driver, rising most recently to $78.70/t cif ARA, close to its own record highs set at the end of June. With oil also bullish, the gas curve's strength strengthened winter 2005-06 base-load prices by more than £1/MWh to £32.30/MWh.

Markets were quoted as far out as summer 2008, where base load was quoted at £26.25/MWh, at a premium over summer 2007 prices, to reflect tighter emissions controls that will kick in during the second phase of the EU emissions trading scheme.

Prompt prices remained dogged by supply concerns, fuelled by an announcement from nuclear generator British Energy (BE) that it will drop its 2004 output from 64.5TWh to 61.5TWh. Units at BE's Hartlepool and Heysham plants remained off line due to technical difficulties. As warmer-than-average temperatures descended on the UK, the grid was placed under greater pressure than it had been in July as air-conditioning demand escalated. This was heightened by the unexpectedly prolonged nature of the heat wave in early

September 2004 base load *£/MWh*



August, which extended for more than a week. September benefited from the prompt's jitters, moving up from £21.10-21.35/MWh to £22.40/MWh in the two weeks.

Within-day prices saw signs of volatility, hitting £75/MWh over the weekend of 7-8 August, and this further supported prompt prices. Peaks attracted the most buying interest among prompt contracts, rising from £23.50/MWh at the start of the period to a high of £30.50/MWh on 2 August. Day-ahead base load moved up less strongly, from a starting level of £20/MWh on 28 July to a high of £22/MWh before a drop in temperatures pushed prices down to £21-21.20/MWh. The contract closed just above £25.25/MWh on 10 August.

Watch for: A revival on prompt prices heading into September as demand increases

Germany

Curve hits new highs on generation costs

The German curve hit record highs in the first two weeks of August as resurgent fuel prices pushed up the projected cost of generation. But oil's gains merely helped fuel the bullish sentiment already in place for much of the summer.

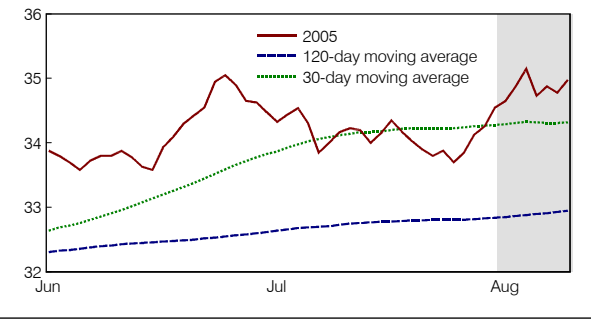
German calendar 2005 base load reached a record high of €35.15/MWh on 4 August, the day after front-month WTI crude oil on the Nymex exchange surged to its own record past $44/bl on Russian and Iraqi supply fears. Year-ahead off peak power also hit a record on that day of €25.56/MWh.

But oil's ability to push up the calendar-ahead in German power weakened by the end of the period. As crude briefly touched yet another high of $45/bl on 10 August, calendar 2005 power struggled to break back through €35/MWh, closing just below this at the end of the period.

Year-ahead coal swaps also supported the year-ahead, ramping up by $4/t over the same period to $73.75/t cif ARA by 10 August.

On the prompt, high temperatures and low wind have been the prevailing weather conditions, causing air-conditioning demand to rise and wind and run-of-river hydroelectric generation to fall. German nuclear plant Brokdorf and two nuclear units in Switzerland, totalling 1,535MW, went off line over the weekend of 7 August. And the 1,288MW

2005 base load *€/MWh*



Gundremmingen C and 1,269MW Neckarwestheim 2 remained off line due to unscheduled delays in their maintenance programmes.

Off peak strength has consistently pushed up the prompt. Day-ahead off peaks at the EEX cleared at €28.74/MWh on 10 August, their highest price in a month, contributing to day-ahead base load prices well above €30/MWh. On 10 August, day-ahead base load closed at €33.72/MWh. For the same reasons, weekends also continue to clear at prices well above the seasonal average — the last two weekends clearing at €26.08/MWh and €25.97/MWh respectively.

Watch for: Long-term end-user buying after the end of the summer break

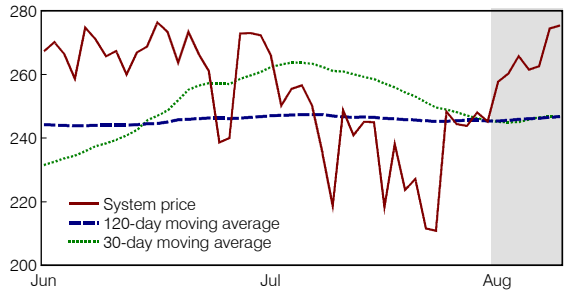
Nordic

High temperatures ramp up prices

High temperatures dominated trading, with day-ahead spot prices soaring to 275.35 krone/MWh on 10 August, up by over 7.5pc in two weeks. Lack of rain is cutting run-of-river hydroelectric generation, leading producers to limit use of stored water reserves. These supply problems are coinciding with a number of planned nuclear maintenance outages. The front month, winter-ahead and winter 1 2005 have all gained NKr5/MWh in a fortnight to reach NKr294/MWh, NKr309.50/MWh and NKr315.50/MWh respectively.

Watch for: A decline in prices if reservoir volumes rise

System price *NKr/MWh*



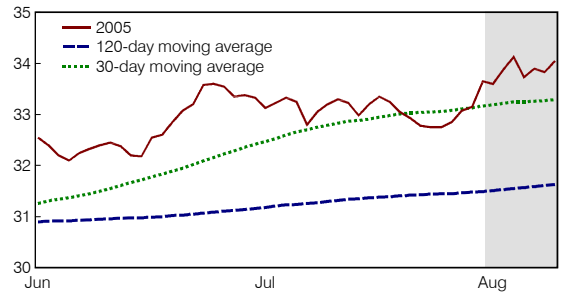
French

Year-ahead hits record highs

Strength in the oil and coal markets pushed calendar 2005 base load to its highest ever level, €34.13/MWh on 4 August. Falling demand and lower temperatures did little to allay fears of heat spikes and shortages of water for hydro-electric generation and nuclear cooling. Strength in the German off-peaks continued to bolster French prices. Day-ahead gained almost €2.50/MWh from a fortnight ago to around €31/MWh, while September also climbed over €1/MWh to €31.70/MWh.

Watch for: Prompt strength easing as spike fears fade

2005 base load *€/MWh*



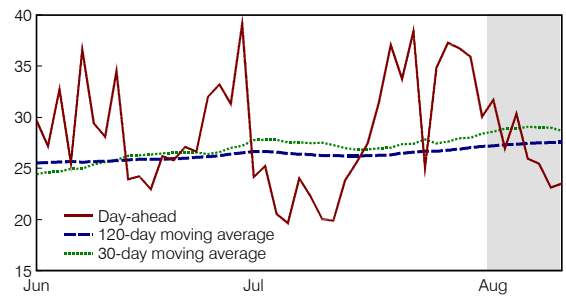
Spanish

Plummeting demand hits spot

The system price was cut by more than a third over the period to €23.50/MWh, wiping away July's gains as holiday season demand kicked in. Peak demand dropped by over 5GW to 29.5GW, making no dent in lower-than-average hydro levels. Participants said over-the-counter trading was being sapped by the exchange, but one exception was a 50MWh deal for day-ahead base load, reported at €27.25/MWh on 9 August. September base load fell by €2/MWh to €31/MWh, bringing it in line with the quarter-ahead.

Watch for: Rising temperatures lifting spot prices

Day-ahead base load *€/MWh*



Dutch

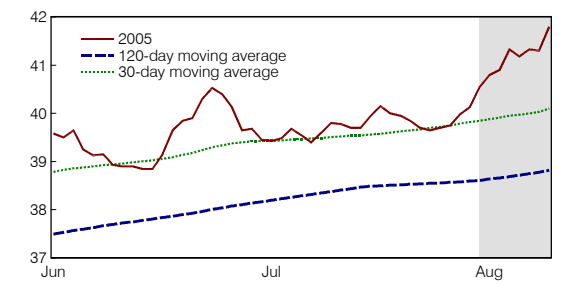
Bullish fuels support curve

Renewed strength in the crude oil and European coal markets lifted the Dutch year-ahead to new highs in the period. Calendar 2005 base load gained around 4.5pc to €41.80/MWh, while the backwardation in the fuel markets saw its premium over 2006 base load widen by €1.15/MWh to €1.83/MWh.

Spot prices were lifted on the back of rises over the border in Germany, as a spell of hot weather raised demand and re-awakened fears of production cuts due to cooling water restrictions. The September contract rallied by over €3/MWh to €38/MWh.

Watch for: The build-up to Nuon's virtual capacity auction

2005 base load *€/MWh*



Shaded area on graphs refers to the last two weeks trading covered in the market commentary

Argus OTC prices (base load)

	Jul 03	Aug	Sep	Oct	Nov	Dec	Jan-04	Feb	Mar	Apr	May	Jun	Jul
UK market (£/MWh)													
Day-ahead	29.88	25.27	16.37	24.73	25.14	26.03	24.13	20.14	20.56	19.64	20.90	21.86	21.73
Week-ahead	20.93	24.13	17.60	25.86	26.83	26.76	24.78	19.88	19.49	19.29	19.82	21.91	20.82
Month-ahead	17.20	20.26	19.80	28.40	29.94	29.21	23.84	18.67	18.48	19.24	20.35	21.04	20.87
4Q 04	-	-	-	23.30	23.51	23.48	23.69	23.28	24.23	25.4	27.39	28.75	27.39
1Q 05	-	-	-	-	-	-	26.43	27.63	26.40	28.43	31.35	31.12	32.54
2Q 05	-	-	-	-	-	-	-	-	-	21.87	23.75	25.36	25.57
3Q 05	-	-	-	-	-	-	-	-	-	-	-	-	25.01
Summer 2004	16.56	17.41	18.76	19.15	19.46	18.54	18.81	17.83	19.34	26.92	29.37	30.04	29.89
Winter 2004-2005	21.76	22.69	23.13	24.85	24.97	24.54	25.04	25.41	24.87	21.37	23.16	24.99	25.23
Summer 2005	19.30	20.10	21.67	22.25	21.24	20.03	21.51	21.83	22.23	28.09	29.89	30.49	30.86
Winter 2005-2006	-	-	-	29.15	28.82	28.08	27.87	28.77	27.12	21.96	23.28	25.26	25.18
German market (€/MWh)													
Day-ahead	45.61	43.25	32.62	39.28	35.72	33.48	31.91	29.71	32.83	28.55	31.57	31.31	30.16
Week-ahead	38.27	41.80	29.58	35.85	35.32	29.34	31.14	28.51	28.45	26.03	26.89	28.75	27.62
Month-ahead	28.55	36.77	31.22	37.39	35.99	37.58	32.54	28.58	27.14	25.72	29.18	29.60	28.70
4Q 04	-	-	-	32.97	34.43	33.38	33.99	33.35	32.68	33.03	34.23	35.34	35.15
1Q 05	-	-	-	-	-	-	35.18	35.37	34.31	34.85	36.30	38.26	38.00
2Q 05	-	-	-	-	-	-	-	-	-	29.28	30.07	31.19	31.27
3Q 05	-	-	-	-	-	-	-	-	-	-	-	-	31.33
2005	29.48	29.87	30.01	31.53	32.92	32.40	32.73	32.71	31.52	31.78	32.86	34.14	34.13
2006	30.25	30.91	30.88	32.53	34.02	33.80	33.80	33.84	33.08	32.86	33.57	34.20	34.31
2007	-	-	-	-	-	-	34.84	34.79	34.24	34.10	34.77	35.15	35.21
French market (€/MWh)													
Day-ahead	43.18	39.19	31.61	38.76	34.71	31.04	31.13	29.31	32.71	28.37	29.67	31.42	30.01
Week-ahead	39.53	37.68	28.66	35.63	34.34	26.84	29.85	27.84	28.32	25.82	25.54	28.17	27.01
Month-ahead	26.53	35.91	30.16	36.54	35.38	36.52	31.23	27.22	26.43	24.76	27.48	28.44	27.54
4Q 04	-	-	-	-	-	-	32.78	32.26	31.59	32.18	33.27	34.42	34.53
1Q 05	-	-	-	-	-	-	-	-	-	33.96	35.20	37.21	37.37
2Q 05	-	-	-	-	-	-	-	-	-	-	-	-	29.95
Summer 2005	-	-	-	-	-	-	-	-	-	-	-	-	30.03
2005	-	-	-	-	-	-	31.12	31.17	30.06	30.45	31.44	32.75	33.10
Dutch market (€/MWh)													
Day-ahead	47.91	69.26	42.12	82.02	89.58	49.82	38.44	36.92	34.76	31.71	37.03	36.44	30.47
Month-ahead	34.93	48.70	43.67	56.18	51.90	49.97	42.75	39.24	34.57	33.26	38.02	33.32	32.98
4Q 04	-	-	-	37.37	38.60	39.23	42.03	41.84	41.24	41.64	42.53	40.05	38.91
1Q 05	-	-	-	-	-	-	41.48	42.22	41.99	41.45	43.67	43.44	42.98
2Q 05	-	-	-	-	-	-	-	-	-	35.27	36.10	36.76	37.58
3Q 05	-	-	-	-	-	-	-	-	-	-	-	-	37.84
2005	32.33	32.84	33.20	35.26	35.52	35.57	36.85	37.53	37.94	37.80	39.00	39.52	39.79
2006	-	-	-	-	-	-	36.88	37.41	37.50	37.03	37.84	37.82	37.90

Argus OTC prices (peak load)

	Jul-03	Aug	Sep	Oct	Nov	Dec	Jan-04	Feb	Mar	Apr	May	Jun	Jul
UK market (£/MWh)													
Month-ahead	23.73	31.39	25.92	44.19	42.82	41.57	31.06	22.62	22.44	23.40	25.52	27.41	26.55
4Q 04	-	-	-	31.75	32.02	30.65	30.64	30.21	30.92	31.49	33.53	36.04	33.99
1Q 05	-	-	-	-	-	-	32.63	32.86	31.25	35.28	37.87	38.96	40.30
2Q 05	-	-	-	-	-	-	-	-	-	24.61	26.01	28.49	30.50
3Q 05	-	-	-	-	-	-	-	-	-	-	-	-	29.86
Winter 2004-2005	30.52	33.23	32.43	33.68	32.92	31.68	31.58	31.38	30.69	33.40	35.64	37.78	37.04
Summer 2005	23.80	25.62	27.94	28.71	26.84	25.17	26.16	25.55	26.51	26.36	27.70	29.78	30.19
Winter 2005-2006	-	-	-	42.34	39.44	34.26	33.87	34.07	32.26	34.21	35.72	36.93	37.33
Summer 2006	-	-	-	-	-	-	-	-	-	26.80	28.14	30.25	30.36
German market (€/MWh)													
Month-ahead	47.26	62.09	46.47	60.07	52.01	56.57	46.52	37.76	36.41	35.60	43.69	44.75	42.17
4Q 04	-	-	-	51.38	53.81	51.32	51.01	48.70	46.68	46.80	49.80	51.07	50.29
1Q 05	-	-	-	-	-	-	53.29	52.20	49.36	49.84	53.00	56.06	55.37
2Q 05	-	-	-	-	-	-	-	-	-	42.97	45.51	47.49	47.45
3Q 05	-	-	-	-	-	-	-	-	-	-	-	-	47.52
2005	47.23	47.97	48.04	49.98	52.89	50.74	50.53	48.91	46.42	46.61	49.19	51.40	50.88
2006	48.81	50.49	50.67	52.58	54.83	54.05	53.01	51.41	49.63	49.55	51.35	52.45	52.53
2007	-	-	-	-	-	-	55.01	54.04	52.36	52.13	53.59	55.05	55.29
French market (€/MWh)													
Month-ahead	42.94	61.27	45.76	59.49	51.29	54.79	44.95	35.86	35.28	34.58	40.41	42.73	40.87
4Q 04	-	-	-	-	-	-	49.97	47.24	45.13	45.34	47.98	49.96	49.48
1Q 05	-	-	-	-	-	-	-	-	-	48.51	50.99	54.33	54.19
2Q 05	-	-	-	-	-	-	-	-	-	-	-	-	45.57
Summer 2005	-	-	-	-	-	-	-	-	-	-	-	-	45.62
2005	-	-	-	-	-	-	48.08	47.13	44.70	44.34	46.32	49.17	49.64

All data is calculated on a calendar month basis for ease of comparison among the trading markets.