PLATTS
McGRAW HILL FINANCIAL

ENERGY ECONOMIST

Issue 410 / December 2015

CONTENTS

UK coal plant closures

The UK announced in November that it would phase out all coal plants by 2025, although Energy Minister Amber Rudd did emphasize that this would only occur if sufficient gas-fired plant was built to replace them. There is no certainty that a power market increasingly less driven by fuel costs will provide a positive market signal for gas without incentives.

And, if incentives are provided, it would mean that virtually all new generation capacity in the UK would be receiving a subsidy of some kind, which suggests at the very least some confusion in policy design.

The announcement is nonetheless radical because it is a clear statement that the intention of UK energy policy is now zero coal. Old inefficient coal plant could have been partially replaced with new coal plant, thereby reducing emissions, retaining baseload power output and allowing a gradual transition for communities dependent on coal mining. But it seems coal is not to be allowed even a quota of emissions for the benefits it brings to the generation mix.

New 'clean' coal technologies could have been better encouraged and incentivised, although there seems to be a broad recognition that Carbon Capture and Storage is too expensive, and, if coal is no longer cheap, it loses one of its primary attributes. Producing CO_2 only to incur expense in removing and then storing it in perpetuity is nonsensical, if there are other, cheaper means of generating electricity without producing the CO_2 in the first place.

The problem for coal is separating its energy content from its carbon content in an affordable and practical manner. The simplest way to do this is Coal Bed Methane. This reduces coal's CO_2 emissions to the level of gas with no need for CO_2 stripping, storage or even mining. CBM inspires environmental opposition as well, but if natural gas, or imported LNG from CBM, fits into UK government strategy, then it looks the most viable direction for domestic coal resource owners.

PLATTS
McGRAW HILL FINANCIAL

ENERGY ECONOMIST
Issue 410 / December 2015

ISSN: 0262-7108

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

Associate editor
Henry Edwardes-Evans

Global Editorial Director, Power
Sarah Cottle

Chief Content Officer
Martin Fraenkel

Platts President
Imogen Dillon Hatcher

Advertising
Tel : +1-720-264-6631

Manager, Advertisement Sales
Kacey Comstock

To reach Platts: E-mail:support@platts.com; North America: Tel:800-PLATTS-8; Latin America: Tel:+54-11-4121-4810; Europe & Middle East: Tel:+44-20-7176-6111; Asia Pacific: Tel:+65-6530-6430

Energy Economist is published monthly by Platts, a division of McGraw Hill Financial, registered office: 20 Canada Square, Canary Wharf, London, UK, E14 5LH.

Officers of the Corporation: Harold McGraw III, Chairman; Doug Peterson, President and Chief Executive Officer; David Goldenberg, Acting General Counsel; Jack F. Callahan, Jr., Executive Vice President and Chief Financial Officer; Elizabeth O'Melia, Senior Vice President, Treasury Operations.

Oil price challenges Gulf States' economic model

Sustained low oil prices are having a huge impact on the finances of the Gulf states. The six countries of the Gulf Cooperation Council all rely on oil and gas exports to power the rest of their economies and maintain social cohesion, but falling revenues are forcing them to dig deep into their reserves. Maintaining high levels of subsidies across the energy sector looks increasingly challenging. **Neil Ford**

The states of the Gulf Cooperation Council – Saudi Arabia, Oman, Qatar, Kuwait, Bahrain and the UAE – are better prepared than most oil exporters to withstand an extended period of low prices because of their Sovereign Wealth Funds, strong reserves levels and low levels of debt, but the implications of any remedial fiscal strategies are as daunting as anywhere in the world. Governments across the region face difficult decisions, as spending cuts and/or tax increases could provoke popular discontent.

The price of Brent crude oil has fallen from $116/barrel in June 2014 to $44/b by mid-November this year, well below what is sustainable in the region in fiscal terms. Different organizations come up with very different figures in assessing the GCC states' budget break-even price of oil. It is far from an exact science and much depends on the oil price forecast used.

Kuwait, the UAE and gas-rich Qatar are generally considered to be in the strongest fiscal positions and it is perhaps no surprise that Bahrain is the weakest. The government of Bahrain faces the biggest threat to its existence and could have been toppled in the Arab Spring, if it were not for the support of the Saudi security services.

Manama has increased spending in an effort to calm domestic tensions, but will struggle to sustain that level of expenditure with a low oil price for long. Its oil revenues have fallen by about 65% a year over the past two years, according to government figures.

Precise figures are difficult to access because of the partly secretive nature of state oil company and government finances in the region, but the IMF predicts that Saudi expenditure will be 20% higher than revenues this year. The net value of foreign assets held by the Saudi central bank had fallen from $730 billion in August 2014 to $654.5 billion just twelve months later. It has been suggested both within and outside the country that Riyadh would be prepared to borrow to maintain both its current output strategy and spending levels.

FISCAL BREAKEVEN PRICE FOR GCC STATES, 2015 ($/b)

Country	International Monetary Fund	Deutsche Bank	Institute of International Finance
Kuwait	49.40	78.40	62.80
Qatar	60.00	76.80	65.30
UAE	73.80	80.80	73.60
Saudi Arabia	87.20	104.40	109.40
Oman	102.60	110.00	113.20
Bahrain	127.10	138.10	130.20

Source: IMF, Deustche Bank, IIF

Lower oil revenues will affect economic growth and therefore also the rise in energy consumption. The IMF forecasts that the GDP of the GCC region will grow by 3.4% in 2015 and 3.7% in 2016, well below the region's average rate of 5.8% between 2000 and 2011; and also just ahead of population growth in the region, which is fueled by immigration.

A report published by PwC earlier this year agreed that gas-rich Qatar was best placed to weather low oil prices and predicted average economic growth of 6.2% over the period 2016-20. Gas prices, although markedly lower, have not fallen as far as oil prices, while government spending is still growing very rapidly. It increased by an average of 18% a year between 2008 and 2013, and will continue to grow strongly as the country prepares to host the 2022 FIFA Football World Cup by developing a range of infrastructural projects.

At the same time, the population is growing by 10% as a result of the immigration of foreign working age adults. However, even Qatar has been hit by the downturn, particularly through the cancellation of petrochemical projects and the government's 2016 budget incorporates what will be the first planned deficit in the country's history.

High stakes

In terms of regional stability, the impact on Saudi Arabia is particularly important. Despite some success in diversification, Riyadh generates 85% of its budget revenues from oil. Much of the non-oil economic activity is made up of infrastructural projects, including construction, transport, power and water schemes that rely on government funding. Under its Unified Investment Plan, the government is also seeking to encourage consumption by providing state employees with two months' bonus salary this year.

Both of these approaches cost a great deal of public money, as does the $5.3 billion a year the state spends on water, power and housing subsidies. To cap a very expensive time for the state, Riyadh is also funding its costly military intervention in Yemen, although here too no figures have been made available. Riyadh's finances are also supported to a smaller extent by its SWF, which is more modest than those of the smaller countries in the region in relation to the size of its population.

Saudi Arabia's struggles with low oil prices are partly of its own making. Riyadh's decision to keep prices low by maximizing production is widely regarded as a strategy designed to hit US unconventional oil producers and regional nemesis Iran. Saudi Arabia is producing 10.6 million b/d a day of crude oil, up 900,000 b/d on its 2014 average and most OPEC members states are pumping above quota levels.

While most analysts believe that shale oil is the main target, this seems unlikely. Even if some shale oil firms are forced out of business, production can easily be brought back on stream when prices recover. Mothballed shale oil projects are remarkably quick to bring back into production.

Even if this strategy were to benefit Saudi Arabia, it is unlikely that this would compensate for the huge price Riyadh has paid to date. Non-GCC state Iran, on the other hand, simply cannot afford to sustain the toxic combination of economic isolation and low oil prices. This desperation undoubtedly helped bring about the headline-grabbing nuclear deal.

While most GCC governments are trying to increase state expenditure in order to maintain economic growth and calm social tensions in a conflict-riven region, low oil prices will affect their ability to invest in their non-oil sectors. To varying degrees, all six have talked for many years about diversifying their economic bases, yet still very few GCC citizens work in the private sector.

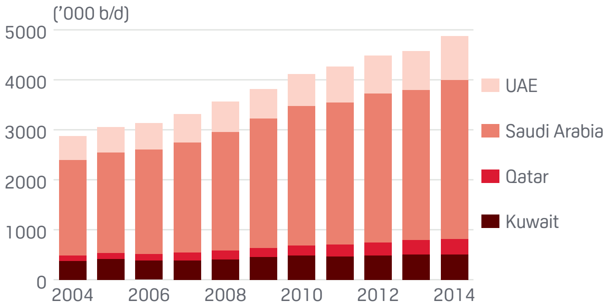
In particular, sustained low oil prices will put long-term economic strategies, such as the UAE's Vision 2021 and Qatar's National Vision 2030, at risk. The region's limited export base is part of the problem. Two-thirds of all GCC exports by value go to non-GCC Asian markets, so slower growth in China is having a big impact. Just 10% of exports go to other GCC countries, 18% to the West and 5% to the rest of the world.

Impact on production

Most OPEC member states have sought to maximize production to maintain market share and revenues. While Saudi Arabia has made use of much of its spare production capacity, the UAE is using enhanced oil recovery techniques to boost output from 2.8 million b/d to 3.5 million b/d by 2017.

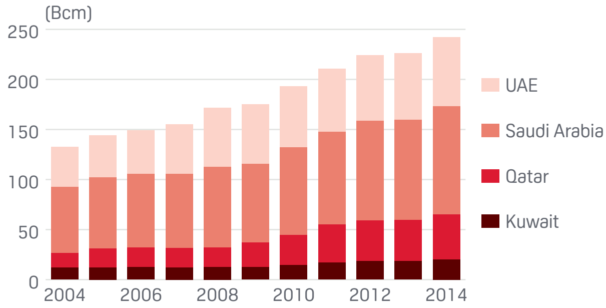
Oil and gas production costs in the region are low in comparison with the rest of the global industry, so it is unlikely that the impact of falling revenues will prevent

MAIN GCC OIL CONSUMERS



Source: BP Statistical Review of World Energy

MAIN GCC GAS CONSUMERS



Source: BP Statistical Review of World Energy

governments from funding new oil projects if required. None of them is in anything like the same position as Nigeria, where the Nigerian National Petroleum Corporation has been unable to fund its share of joint venture projects.

The more important question is whether governments would sanction new oil projects on proven fields by state owned firms at a time of such low oil prices. Many are likely to be postponed because of the low returns on offer. There will also be a big impact on exploration efforts, although there are sufficient proven reserves already in place to allow for higher production in most GCC countries. The six hold 30% of the world's proven oil reserves: Saudi Arabia has 15.7%, Kuwait 6% and the UAE 5.8%.

There is another important repercussion of low oil prices for the region. Saudi Arabia has traditionally been the only country in the world to retain a large amount of spare oil production capacity for an extended period of time. It has built much of its importance on the world stage and within OPEC on its ability to act as a safety valve and provide a stabilizing influence on global oil prices.

Yet while it has increased production over the past two years, it has failed to secure additional spare capacity in compensation, despite ministers' repeated declarations that they could boost output to 15 million b/d, if required. Spare production capacity could now be as low as 1 million b/d, about half its traditional level. It could be that state oil company Saudi Aramco will be given the funds to develop new fields, but it seems more likely that the government is reining in spending.

The most obvious way for the Gulf states to balance the books is to cut expenditure. Since the oil boom in the region began, all governments have followed the same model of social, economic and political development. They have provided generous state support for health, education and other services – often including housing – plus low taxation rates, in return for tight controls on social and religious life.

When oil revenues were plentiful, this trade off was broadly accepted. However, demographic growth and low oil prices make this model difficult to sustain. At the same time, the level of tolerance for any kind of criticism or opposition is falling. There is no legal safety valve for public discontent, so some of this dissatisfaction finds a home with the Islamist extremists who oppose the region's royal dynasties as much their western allies. This in turn encourages governments to increase spending in order to buy off discontent.

Impact on energy subsidies

One aspect of their cradle-to-grave support has direct relevance for the energy sector. Rapidly rising power, fuel and water consumption would generate government revenues in many countries, but not in the GCC region, where government hugely subsidizes all three. Very low cost power and water is viewed by many as part of the social contract between the state and citizens.

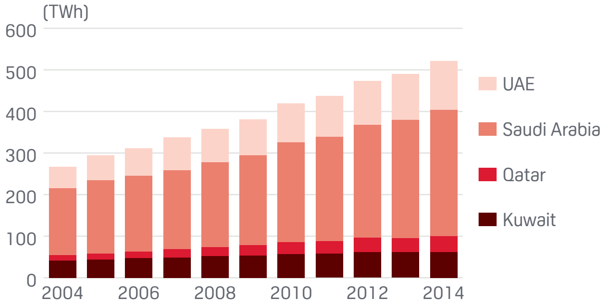
Power, water and gas subsidies both erode government finances and consume energy resources that would otherwise be available for export to generate more income. Subsidies account for 20% of Abu Dhabi's entire government budget. The domestic price of crude oil in Saudi Arabia is just $5/b, while the country has the cheapest gasoline in the GCC at $0.15 a liter. Qatar and the UAE charge $0.26/l and $0.47/l respectively, still well below the average for the Middle East.

According to The Abdullah Bin Hamad Al Attiyah Foundation for Energy & Sustainable Development, GCC oil demand has increased by an average of 9% a year between 1973 and 2014, from less than 500,000 b/d to more than 4 million b/d. This is faster than GDP growth, making its energy consumption increasingly inefficient in purely economic terms.

The Foundation predicts that the volume of Saudi crude available for export could fall below 5 million b/d, although domestic refineries also export fuel. Sustaining this level of growth over the next decade would necessitate both a big recovery in oil prices and a massive increase in regional production. This combination will not be achieved, so Gulf governments face some difficult choices, particularly over their subsidy regimes.

Water consumption is as important to the energy sector as electricity consumption because so much of the region's water demand is satisfied by desalination plants that consume huge amounts of energy. Yet citizens in the smaller states consume water as if it were a plentiful and cheap resource.

GCC ELECTRICITY GENERATION



Source: BP Statistical Review of World Energy

Gardeners use water liberally during the middle of the day when evaporation rates are highest, while water and power companies sometimes fail to sanction those who do not pay their bills. As a result, average water consumption within the GCC region now averages 550 liters per person per day. Even putting per capita consumption aside, rapid population growth in Qatar and the UAE is driving up water consumption.

Changing patterns of consumption will require social change. In January, the UAE increased residential power tariffs for citizens to 5.5 fils/kWh (1.49 US cents/kWh) and 21 fils/kWh for foreign residents. Water tariffs for foreign residents jumped by 170%, while water charges were introduced for citizens for the first time.

It was followed by Bahrain, which increased the regulated price of gas sold to industrial customers in April and has begun to withdraw food price subsidies. In November, the government announced a review of all power and fuel subsidies with a view to removing all of them, while it has also proposed the introduction of value added tax across the GCC region.

The latter measure is something that the IMF has advocated for many years. Most recently, Riyadh announced that it will increase its water tariff for industrial, government and large company users from 4 riyals/cubic meter ($1.07/cu m). to 9 riyals/cu m from the middle of December.

Switching energy consumption

The other obvious method of maximizing oil exports is to reduce domestic oil consumption in favor of other energy sources. Saudi Arabia, Kuwait and to a lesser extent Qatar continue to rely on oil-fired plants for much of their generating capacity and all hope to move from oil to gas as a feedstock. However, Kuwait has been a net gas importer since 2008 and will have to fund additional imports.

The Saudi government is attempting to rein in domestic oil consumption by committing Saudi Aramco to invest $9 billion over five years to increase its 2011 gas output from 280 MMcm/d to 420 MMcm/d, but this will only cover the increase in power demand over that period, rather than displacing oil consumption.

Gas prices within the region are well below international standards at just $1-2/MMBtu, which discourages the development of local non-associated fields, but encourages inefficient consumption. Oman has already cut its LNG exports, while the UAE will soon be in the unusual position of both exporting and importing LNG, in a sign that its government has greatly underestimated the rise in gas consumption. Moreover, UAE firm Dana Gas is cutting its expenditure in anticipation of sustained low oil and gas prices.

However, the UAE is leading the way in promoting the adoption of alternative forms of power generation. It has four nuclear reactors under construction. The World Nuclear

Association says the first is 75% complete and may be online as early as 2017. In total 5.6 GW is planned at the Barakah site.

With such a long time lead, the project was planned long before the drop in oil prices, but the addition of nuclear power will help the UAE maximixe its oil exports. In addition, it has begun to develop what it hopes will be 1 GW of solar PV and solar thermal generating capacity. Dubai's generation mix target for 2030 is 5% solar, 12% clean coal, 12% nuclear and 71% natural gas, with oil phased out entirely.

Saudi Arabia, by contrast, has been reluctant to consider alternative forms of power production, apart from its undeveloped nuclear ambitions. All current power production in the country comes from fuel oil, diesel and gas-fired thermal power plants. The power sector alone consumes almost 1 million b/d of oil during the seasonal peak. However, the Saudi Electricity Company has been tasked with bringing 41 GW of solar generating capacity on stream at a cost of $109 billion by 2032.

Unsustainable economic model

As always, it is difficult to predict how long low oil prices will last. Public statements by international oil companies over the past year have emphasized that a recovery is anticipated, but prices have continued falling. However, in its World Energy Outlook, published in November, the International Energy Agency predicted that global oil demand would increase by just 900,000 b/d per year over the next five years and that prices would take until 2020 to reach $80/b.

Fatih Birol, executive director of the IEA, said: "We estimate this year's investments in oil will decline more than 20%. But, perhaps even more importantly, this decline will continue next year as well. In the last 25 years, we have never seen two consecutive years where the investments are declining and this may well have implications for the oil market in the years to come."

The IEA expects the impact to be spread very unevenly, with the Middle East rapidly gaining market share at the expense of higher cost producers. Under its least optimistic scenario – at least as far as producers are concerned – the IEA predicts that prices will take until 2040 to reach $85/b.

Qatar aside, something will have to give in the Gulf if these forecasts come anywhere close to becoming reality. While Riyadh may welcome the impact that low oil prices have on its religious and geopolitical rival, Iran; and on its oil sector rival, North American unconventional oil; it cannot afford sustained low oil prices with its current social, economic and political policies.

Unless oil prices double over the next five to ten years – which they show no sign of doing – then this model will become untenable. Subsidies cannot merely be trimmed; they may have to be lifted entirely. VAT and other taxes will probably have to be introduced, while economic diversification is becoming a necessity rather than a desirable option. Dubai can get by without oil, but even its remarkable development has been largely financed by oil money from within the region.

India plans massive expansion in coal use

Claims by India's government that thermal coal imports will cease by end-2017 are not quite what they seem, but a fall in thermal coal imports is certainly possible. However, this is not a sign that India is turning its back on coal. The government wants to nearly triple domestic coal production to 1.6 billion tons by 2020, although this goal looks over ambitious. **Sunil Saraf**

India's coal authorities say that growth in the country's coal imports has peaked, while Coal Minister Piyush Goel has predicted that thermal coal imports will cease altogether after 2017. This would be a harsh blow to an already weak international thermal coal market. India's total coal imports reached 212 millon mt in fiscal 2014 and are expected to fall marginally to 210 million mt this year.

Despite rapid growth in domestic coal production over the last 18 months, Goel's claim that thermal coal imports will stop by end 2017 looks unlikely. His forecast also lacks clarity. He seems to be implying that power plants' requirement for domestic coal will be met by domestic production.

This appears to exclude imported coal bought by power plants specifically designed to consume low-ash imported coal.

For the current year, power plants' requirement for (high ash) domestic coal is estimated at 591 million tons. This will be met by 435 million mt from Coal India Ltd, 38 million mt from Singareni Collieries Company Ltd., the country's two commercial mining companies, and 32 million mt from captive mines. 73 million mt of low ash coal will be imported to meet the domestic shortfall of 86 million mt of high ash domestic coal.

It is this segment of coal imports that Goel sees as being eradicated by end-2017. The remainder is made up of thermal coal imports for plant designed to run on low ash imports and metallurgical coal.

Forecast basis

The foundation of Goel's forecast is the recent rise in domestic production. Despite sharply reduced output from captivecoal mines, Indian coal imports fell in each of the three months to September, year-on-year, according to top coal ministry official Anil Swarup.

At the same time, by end-September, India's coal plants had stocks of 26 million mt, equivalent to 22 days of use, compared with 8.58 million mt stocks at end-September 2014. CIL and SCCL delivered nearly 214 million mt coal to power plants between April-September, about 10% more than in the same period last year.

Power plant coal imports during April-September were down by about 7% to 41 million mt compared with the same period in fiscal 2014. Owing to the increase in domestic supply, the country's largest power generator NTPC imported only 6 million mt of coal, in comparison with its target of 22 million mt set by the Central ElectricityAuthority.

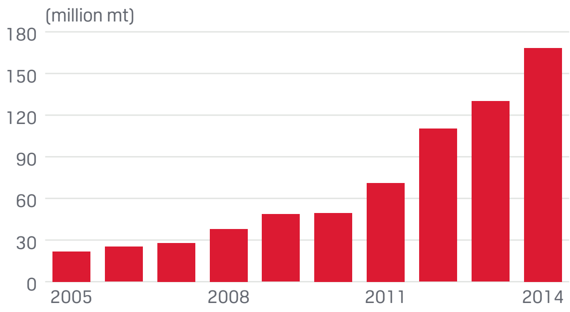
CIL uncertainty

However, unsure if it can maintain the rapid pace of production growth, CIL continues to stick only to its commitment to deliver 67% of the volumes agreed under its Fuel Supply Agreements this year, rising to 75% next year. These FSAs cover 78 GW of power plant commissioned (or still to be commissioned) in the six years to March 2015. About 20 GW remains uncompleted.

FSAs have a provision for CIL to import coal, if producers want the full volumes promised, but CIL imported little less than half a million tons last year and there is little sign of imports so far in 2015. There is another 33 GW of power plant, mostly under construction, which still do not have FSAs, despite being issued with Letters of Assurance by CIL several years ago.

If CIL was to meet all of its commitments under power plant FSAs and LOAs, it would need to deliver 591.4 million mt of thermal coal next year, 630 million mt in fiscal 2017, 658.7 million mt in fiscal 2018 and 678.14 million mt in fiscal 2019. That CIL remains unwilling to convert LOAs into FSAs, which

INDIA'S NON-COKING COAL IMPORTS



Source: Ministry of Coal

carry penalties for under-delivery, suggests it harbors some doubt that it can sustain the increase in production growth of the last 18 months.

Green spin

India's claims of an end to thermal coal imports has also been given a green spin in some quarters, but to large extent it reflects a failure to push forward other means of electricity generation. The country's hydro power projects are beset by unresolved issues, growth in nuclear power remains mired in accident related liability problems, and no more gas-fired power plant is being built because of a lack of cheap domestic gas.

As a result, the government is focused on coal and renewables. Renewables' share of the generation mix is forecast to rise to 40% within the next 15 years, compared to 17% at present. This target has been pledged as part of India's Intended Nationally Determined Contributions submission to the COP21 Summit in Paris. However, that does not mean that coal's current 60% share of power generation will fall significantly.

Coal dominance

Coal-fired power plants currently make up 166 GW of the country's 270 GW generating capacity. The CEA has a priority list of over 150 new, predominantly coal-fired, thermal power projects, totaling 191 GW, which it thinks deserve priority for sanction based on domestic mines providing long-term coal supplies.

The National Democratic Alliance-led coalition government aims to nearly triple domestic coal production to 1.6 billion tons a year by March 2020. Domestic thermal coal is priced much lower than imported coal and is thus the first preference for all consumers. Demand is such that consumers have been lifting all coal available in the open market at a premium over the notified price for coal supplied under long-term contracts by CIL.

The notified price of non-coking coal at the mine head currently ranges from Rs400-Rs1600 ($6.1-$24.6) per ton for coal with heating value of 2,500-5,800 kcal/kg. CIL also sold 45 million mt on the open market last year at a premium of nearly 64% to the notified price. This premium has fallen this year as a result of lower prices on international markets.

Supply growth

Demand remains much higher than the domestic coal industry's capacity to supply. Imports have nearly tripled since fiscal 2011. Growth in imports last year of 45 million mt was the highest annual rise yet.

However, domestic supply also rose by a robust 47 million mt. CIL accounted for 32 million mt of this and the company expects to add over 55 million mt more this year to hit its 550 million mt annual output target. The company achieved nearly 9% output growth to 230 million mt in April-September, the first six months of the current fiscal year.

This has given it confidence that annual growth will be in double digits because output typically picks up after the June-September rainy season. In addition, about 93% of CIL's annual production is from open-cut mines, and it has reported a 36% rise in over-burden removal to 510 million cubic meters in the first half of the fiscal year.

The grander target CIL has been charged with is to double output to 1 billion mt by 2020, which means the company would provide two-thirds of total planned output in that year. The company has completed planning in terms of land requirement, environment protection, human resources and technology to build production to 908 million tons and is working on plans for the additional 100 million tons required.

Current forecasts show annual increases of 50-60 million mt in the next two years to 597.6 million tons in fiscal 2017 and 660.7 million mt in fiscal 2018. Output growth then accelerates by 100 million mt in each of the subsequent two years to 773.7 million mt in 2019 and 908.1 million mt in 2020.

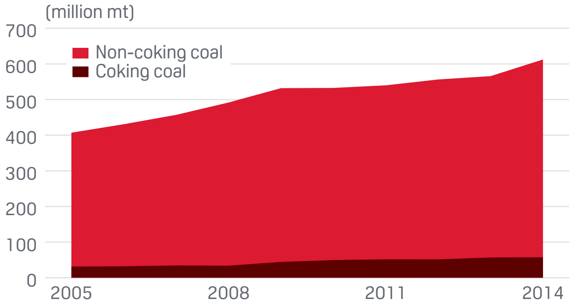
Expansion plan challenges

There are three broad elements to the strategy. The main contributor is mine expansions, which are currently expected to deliver 78% of output growth, producing a total of 561.5 million mt by 2020. New mining projects will add 181.6 million mt. Existing mines not targeted for expansion are expected to produce 163 million mt, a decline of about 33 million mt on 2015 levels.

Cash-rich CIL has the funds to carry out its plan. The real barrier has been delays relating to environment and forestry approvals, land acquisition and agreeing relief and rehabilitation for people uprooted from the mining sites. Out of the 129 new coal mining projects to be taken up during the 2012-2017 five year development plan, by August this year, only 20 had all the necessary administrative approvals. A further 20 had provisional clearance.

Many of India's large coal deposits are in forest areas, where open cast mining would have a severe environmental impact. Years of debate over forest zoning into 'violable' and 'inviolable' zones have yet to produce any clear results. The previous government proved very reluctant to approve mining in forest areas, despite an obligation on miners to replace all damaged trees with replanting. CIL says it has planted more trees that its mining activities have destroyed, but this didn't make gaining approvals any easier.

INDIAN COAL PRODUCTION



Source: Ministry of Coal

Under the current government, the environmental authorities are taking a more accommodating approach and appear to be willing to permit coal mining with what they call 'minimum damage' to the environment. However, this does not overcome forest-related issues at the state and local level, where the registration of applications and then grants of no-objection certificates for the diversion of forest land to non-forest purpose can also suffer lengthy delays.

A mismatch of land records between the revenue and forest departments of state governments can take several months and even years to resolve. CIL still had a total of 203 mining projects, including mine expansions, that were awaiting environmental clearance as of March this year.

In addition, the previous government enacted a law in 2013 that provides for heavy compensation for land acquisition and requires both a social impact study and the consent of a majority of the people in the area affected by the project. Attempts by the new government to remove some of these conditions has been blocked by opposition parties who said the government was working against the interests of farmers.

The NDA recently suffered defeat in elections for the legislative assembly of Bihar state and is sensitive to farming communities are a very important electoral group in India. This suggests the government may shy away from attempting such reform again.

Over 50 of CIL's new mining projects are held up due to land acquisition issues. These can cover a wide variety of problems from delayed notification of identified land, authentication of land records, confirmation of land release – as land owners are proving reluctant to part with their lands even after compensation has been paid – lack of rehabilitation and resettlement sites, and settling hefty compensation claims that go well beyond what CIL would normally expect to pay.

CIL needs to acquire about 8,100 hectares of additional land to hit its 1 billon mt output target. It acquired 3,000 hectares last year, its highest annual total yet. It also obtained environment clearances for 41 mining projects, including expansion schemes. It was these that helped it increase production last year, mainly from existing mines.

One of its major successes was the start to mining at Magadh in Chatra district of Jharkhand state. By 2020, this may become Asia's biggest coal mine with yearly output expected at 51 million mt. The mine is expected to produce about 2 million mt this year.

SCCL is the only other commercial producer of coal. A joint venture between central government and Telengana state, its mining operations are confined to Telengana.

The joint venture produced 52.5 million mt last year and 27 million mt in the first six months of this year. SCCL expects output to rise by 35% to 80 million mt in the next five years. It plans to open 17 new coal mines in three years, including three this year.

Captive coal producers

If SCCL provides an additional 28 million mt by 2020, this still leaves the government short by more than half a billion mt, if it is to hit the 2020 target. This shortfall needs to be met by captive coal producers, which mine coal for their own uses, such as power generation or steel production.

This area is also mired in uncertainty. 218 captive mine developments have been allocated over the last two decades, but 204 have been cancelled, owing to an ongoing scandal relating to allegations of large-scale corruption in captive mine licensing. The Supreme Court ruled in September 2014 that the awards had been arbitrary and illegal.

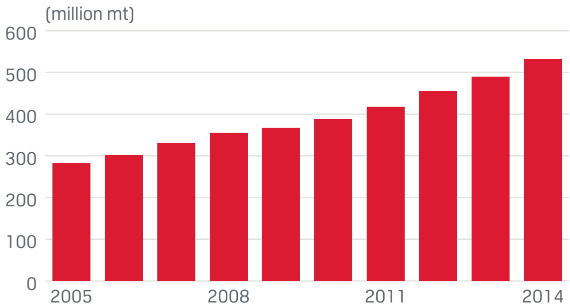
Only 42 captive mines were actually developed, as captive miners have faced the same, and sometimes worse, problems than CIL. Production was allowed to continue at these mines until March this year. Auctions of licenses saw new owners brought in at about 30 mines, but only seven are currently producing.

Others are struggling to get various administrative approvals to allow production to resume, despite the enactment of a special legal framework to ensure a smooth transition of ownership. Some state governments have different interpretations of the new legal framework, compared with what the national government intended.

In addition, some power producers, haunted by the severe coal shortages of the past, appear to have bid too high for the licenses, leaving them with commercially unviable mines. Other mining blocks' ownership remain the subject of litigation.

The government forecast that the re-allotment of licenses would see production from these mines rise 42 million mt this year to 93.97 million mt, following a 34% increase to 52 million mt in 2014. However, their current status suggests production in 2015 will be little over half that of last year at around 25 million mt.

INDIAN POWER PLANT CONSUMPTION OF COAL



Source: Central Electricity Authority

GRID-CONNECTED COAL-FIRED PLANT IN INDIA

Year	Installed capacity (MW)	Electricity generation (TWh)	Plant load factor %
2011/2012	112,022.99	585	73.65
2012/2013	130,220.85	659	69.71
2013/2014	145,233.39	714	65.46
2014/2015	164,635.88	800	64.07
2015/2016 till september	169,117.88	412	60.43

Source: Central Electricity Authority. Electricity generation and plant load factors have been derived from generation capacity monitored by the CEA, which tends to be 5-10 GW lower than actual installed capacity.

In addition, re-licensing of the undeveloped cancelled mines is moving slowly. Only about one-third, including nearly 40 given to government enterprises under new rules, have been allotted out of the 204 cancelled locks.

Nonetheless, production from captive mines in the next few years could still make a significant dent in imports. India's largest power utility, NTPC Ltd. expects mining to start early next year at its first captive mine Pakri Barwadih in Jharkhand state after several years of delay.

This mine is expected to yield 315 million mt coal over its life, reducing NTPC's import requirement, which amounted to 16 million mt last year. NTPC has been allocated five further mining blocks, which have 6 billion mt of reserves. NTPC consumes 165 million mt coal annually, so successful development of its reserves could have an impact on imports.

The government has not yet mustered the political courage to open coal mining up to private investors for sale in the open market, although it won the legislative authority to do so earlier this year. This legislation had been blocked for 15 years by coal mine workers unions.

Transportation issues

If there are doubts about the industry's ability to hit production targets, there are also issues relating to coal transportation. Most coal in India is transported by rail, but supplies are often disrupted by a lack of loading rakes and line congestion. In recent years, no less than 40 million mt of stock has been lying at CIL mines, despite shortages at power stations.

Construction of the nearly 1,950 kilometer Luidhiana-Dankuni dedicated rail freight corridor will be a big boon for fast and efficient movement of coal from coal-bearing states in eastern India to the northern region. However, the double track is not expected to be fully commissioned until 2019.

Three other critical rail lines are under construction but all have suffered major delays. Together, they will help transport about 300 million mt coal annually. The 53 km Jharsugda-Barpali-Sardega line in Odisha state was launched nine years ago and is expected to be ready in mid-2016.

Construction of the two other lines, the 94 km Tori-Shivpur-Kathotia in Jharkhand and the 180 km east corridor in

INDIAN POWER PLANT COAL IMPORTS (million mt)

	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016 Planned	2015/2016 (Actual up to September 2015)
Power plants designed to run on domestic coal							
Haryana Power Generation Corporation Ltd.	0.08	1.22	0.79	1.47	0.95	1.00	0.19
Rajasthan Vidyut Utpadan Nigam Ltd.	0.45	0.00	1.18	0.29	1.61	1.80	0.17
Punjab State Power	0.00	0.00	0.00	0.00	0.00	0.50	0.33
Uttar Pradesh Rajya Vidyut Utpadan	0.00	0.00	0.00	0.00	0.00	0.50	0.00
Madhya Pradesh Power Generation Corporation	0.08	0.40	0.36	0.62	0.38	1.20	0.16
Torrent (Sabarmati C)	0.48	0.27	0.59	0.46	0.56	0.40	0.43
Gujarat State Electricity Corporation	1.15	0.65	0.47	0.10	1.11	1.00	0.42
Maharashtra State Power Generation Corporation	2.32	2.50	3.04	2.56	2.32	5.20	0.67
Reliance Power (Dahanu)	0.82	0.78	0.79	0.68	0.75	0.60	0.12
Andhara Power Generation Corporation	0.72	1.69	1.73	1.58	1.65	4.40	0.10
Tamil Nadu Generaiton and Distribution Company	2.18	3.12	3.53	5.56	7.65	5.00	3.30
Karnataka power Corporation	1.08	1.27	1.64	1.38	0.92	2.00	0.18
Damodar Valley Corporation	0.32	0.00	1.20	1.91	0.00	1.00	0.00
CESC	0.37	0.18	0.43	0.38	0.31	0.10	0.16
West Bengal Power Development Corporation	0.40	1.03	1.11	0.62	0.00	0.40	0.00
NTPC	10.52	12.07	8.83	10.71	16.18	22.00	6.39
NTPC-Joint Venture (Indira Gandhi)	0.00	0.27	1.19	1.17	0.65	1.50	0.26
Reliance Power (Rosa)	0.00	0.88	2.09	1.76	2.21	2.00	0.05
TATA (Maithon Right Bank)	0.00	0.00	0.00	0.12	0.01	0.00	0.00
Jindal Power Limited (Mahatma Gandhi)	0.00	0.00	0.06	1.40	0.80	2.60	0.22
Lanco (Anpara)	0.00	0.00	0.54	0.57	0.56	1.50	0.29
Lanco (Pathadi)	0.00	0.00	0.30	0.00	0.00	0.00	0.00
Vedanta (Jharsuguda)	0.00	0.00	0.02	0.00	0.30	1.40	0.14
Jaiprakash Bina	0.00	0.00	0.00	0.01	0.08	0.30	0.00
Talwandi Sabo Power	0.03	0.00	0.00	0.42	0.12	1.80	0.12
Ntecl (Vellur)	0.00	0.00	0.21	0.79	1.70	1.80	1.03
Adani Power Maharashtra (Tirora)	0.00	0.00	0.06	1.41	2.33	4.70	1.56
Moser Bear (Annuppur)	0.00	0.00	0.59	0.00	0.00	1.00	0.00
GMR Emco Energy	0.00	0.00	0.00	0.19	0.43	0.40	0.04
NTPC SAIL (Bhilai)	0.00	0.00	0.00	0.32	0.46	0.30	0.06
GMR (Kamalanga)	0.00	0.00	0.35	0.05	0.56	0.50	0.38
Wardha Power Company (Warora)	0.09	0.00	0.00	0.00	0.00	0.00	0.02
Bajaj Energy	0.00	0.00	0.00	0.00	0.00	0.10	0.00
Adani Power Rajasthan (Kawai)	0.00	0.00	0.01	1.25	3.18	2.00	1.42
Jindal Power (Tamnar)	0.00	0.00	0.00	0.00	0.00	0.50	0.02
NLC Join Venture (Tuticorin)	0.00	0.00	0.00	0.00	0.00	0.80	0.00
Haldia Energy	0.00	0.00	0.00	0.00	0.00	0.20	0.32
Vidharba Industries Poweer (Butibori)	0.00	0.00	0.00	0.00	0.28	0.50	0.30
Thermal Powertech (Pynampuram)	0.00	0.00	0.00	0.00	0.00	1.00	0.34
KSK Energy Ventures (Akaltara)	0.00	0.00	0.00	0.00	0.00	0.00	0.06
Nabha Powere (Rajpura)	0.00	0.00	0.00	0.00	0.52	1.00	0.19
RattanIndia Power (Amarvati)	0.00	0.00	0.00	0.00	0.00	0.00	0.17
Sub total (A)	21.09	26.33	31.11	37.78	48.58	73.00	19.61
Power Plants designed on imported coal							
Tata Power (Trombay)	2.64	2.57	2.87	2.62	2.04		1.42
JSW Eenergy(Ratnagiri and Torangullu)	2.21	6.18	7.16	5.93	6.27		2.72
Adani Power (Mundra)	3.70	7.29	11.01	12.38	14.81		8.40
Adani Power (Uduppi)	0.85	1.62	2.67	3.10	2.70		1.51
Coastal Gujarat(Mundra)	0.00	0.00	5.23	11.85	10.49		4.94
ESSAR (Salaya)	0.00	0.00	1.83	2.92	3.00		1.14
Simhapuri Energy	0.00	0.00	0.57	1.45	2.30		1.14
Meenakshi Energy (Thaminapattnam)	0.00	0.00	0.32	1.06	1.10		0.44
Ind Barath (Tuticorin)	0.00	0.00	0.00	0.92	0.00		0.00
Sub Total (B)	9.40	17.66	31.66	42.23	42.71		21.71
TOTAL (A+B)	30.49	43.99	62.77	80.01	91.29		41.32

Imports include those for grid-connected power plants only and do not include captive power plant imports. 2015/2016 imports are those planned by the Central Electricity Authority. The CEA does not plan for power plants designed to run on imported coal, imports for which are expected to be the same as last year

2015/2016 imports are what have been planned by Central Electricity Athority which does not do such planning for power plants designed on imported coal and such imports are expected to be the same as last year

Source: Central Electricity Authority

Chhattisgarh, is moving slowly, owing to environmental and other issues. These two railways are designed to connect the major coal producing fields of CIL subsidiaries Central Coalfields Ltd., Maharanadi Coalfields Ltd. and South Eastern Coalfields Ltd. Together, these companies are expected contribute about two-thirds of CIL's targeted 1 billion mt output by 2020. Neither railway is likely to be ready until early 2018.

Initially funded by the cash-strapped railway administration, these lines are now joint ventures, receiving funding from CIL and their host states.

Such joint ventures are seen as the means of overcoming other transportation bottlenecks. CIL and the rail authorities are looking at 60 more such schemes, but any benefits are unlikely to be evident until after 2017.

Demand side

CEA data shows that power producers connected to the grid consumed 531.5 million mt of coal in 2014, while another 53 million mt was consumed by captive users. The power sector accounted for 80% of the total 754 million mt of non-coking coal supply last year.

This includes 168 million mt of imports, of which power producers serving the grid alone accounted for 91 million mt. The CEA estimates that power plant demand for coal will rise to 633 million mt this year, requiring 115 million mt of thermal coal imports.

However, the country's expansion of coal-fired generating capacity appears to be slowing, after reaching a record 20 GW of new additions last year. The expansion was the result of several major new power projects launched during six years of high economic growth from 2004-2010, which attracted much private investment.

The pace of expansion slowed in the current fiscal year, with less than 5 GW new capacity commissioned in the first six months to September. This is part of about 20 GW capacity that had been expected to complete by March 2015, but has been delayed by a variety of issues such as administrative approvals, equipment supply, transmission lines, law and order problems and the financial weakness of state distribution utilities.

The recent economic slowdown, combined with fuel shortages and other factors, has seen the launch of private sector projects virtually dry up. This has restricted growth in this area to cash- rich companies like NTPC, which accounts for over 25% of annual power generation. Having built over 45 GW capacity, mostly coal-fired, the company has another 23 GW under construction, 9 GW in bidding stage and projects totaling 16.6 GW under consideration.

In addition, a lack of cash has meant that distribution utilities have been unable to sign up to long-term Power Purchase Agreements with generators, and PPAs are essential for getting a long-term Fuel Supply Agreement with CIL.

There has also been a tendency amongst state distribution utilities to reduce power purchases, owing to their funding constraints. As a result, power generators are being forced to generate less, even if they have PPAs with the utilities. Power plant load factor has fallen over the last few years, dropping to about 65% in 2014 from 75.2% in 2011.

The central government in November announced another bailout package for the bankrupt distribution utilities, just three years after the launch of the last financial restructuring scheme. This is expected to make the utilities profitable within three years and increase their financial capacity to buy more electricity. State governments will have to take over the utilities' massive debts in the next two years as part of the new restructuring package, assuming that they agree to the tough conditions laid down. This is unlikely, as in the past, to prove a smooth process.

Russia and China best hope for nuclear revival

Any revival of the nuclear industry's fortunes is likely to be led by China and Russia. The new designs of Western technology providers appear heavily, if not fatally, damaged by huge time and cost overruns. However, Russian and Chinese designs have yet to be tested by independent, open and transparent regulatory bodies. Their ability to deliver promised cost reductions under such scrutiny is doubtful. **Stephen Thomas**

The COP21 summit in Paris has led to renewed predictions of a nuclear revival based on the need to substitute fossil-fuel generation with low-carbon energy sources. If this latest forecast is to be realized, it is most likely to be driven by the Russian and the Chinese nuclear industries. These are strongly backed by their national governments and have a relatively healthy domestic market.

In contrast, the two leading designs from traditional suppliers, the Areva European Pressurised Water Reactor (EPR) and the Toshiba/Westinghouse AP1000, appear badly, perhaps terminally, damaged by appalling construction cost and time overruns.

Moreover, talk of new designs, such as small and medium-sized reactors or Generation IV designs, appears optimistic. Commercial deployment is more than a decade away, even if these new designs do turn out to be technically and economically viable.

The common assumption is that reactors from Russia and China will be significantly cheaper than reactors like the EPR or AP1000, and will come with a comprehensive government-backed package of finance, training and fuel cycle services. The availability of finance is perhaps the biggest barrier to new nuclear ordering, so this would be a major benefit especially for weaker economies.

However, there are doubts that these low cost assumptions are valid. Russia, with its AES-2006, and China, with its Hualong One design, claim they meet current best-practice and would satisfy European and American regulators, but this remains for both an untested proposition – as is their ability to build nuclear reactors abroad.

Russian designs
Russia's civil nuclear industry dates back to the 1950s, but up until the Chernobyl disaster and the break-up of the Soviet Union, it exported almost exclusively to other Soviet Republics (Ukraine and Lithuania) and to Comecon countries (Czechoslovakia, Hungary, Bulgaria and East Germany).

Most of the exports used the Russian version of the Pressurised Water Reactor, the VVER, with the Chernobyl design exported to Ukraine and Lithuania. The only export outside the Eastern Bloc was of two reactors of an early VVER design to Finland. Siemens was heavily involved in the design of the Finnish reactors providing the instrumentation and control.

The Chernobyl disaster badly damaged the credibility of Russia's nuclear technology and it responded with two new designs, AES-91 and AES-92, which incorporated features, like 'core-catchers' that are now common in Western designs.

Despite their names, these were not ordered until 2001. The AES-91 was developed by the St Petersburg office of Rosatom and two reactors were exported to China (Tianwan), where they have been in service for nearly a decade. They took 6-7 years to build, rather long by Chinese standards, but appear to have operated reliably and were followed up by two more orders for the same design at the same site in 2012-13.

The AES-92 was produced by Rosatom's Moscow office and two orders were placed for India (Kudankulam). The first unit entered commercial service in 2014, the second is expected to enter commercial service in mid-2016, after more than 12 years of construction. These designs, which have about 1000 MW capacity, might still be offered to countries with small grids, such as Jordan, because they are marginally smaller than their successor, the 1200 MW AES-2006.

The AES-2006, which became available in 2007, is not the unified design it is often seen as. Like AES-91 and AES-92, there are two significantly different versions. One is produced by the St Petersburg office, the V-491, which is being built at Leningrad-2, Kaliningrad and Belarus, while the Moscow version, the V-392, which is said to have more passive safety features, is being built at Novovoronezh-2.

Despite not yet operating anywhere, the AES-2006 might already be obsolete in design terms. In 2010, Rosatom announced a new design developed by the Moscow office, the VVER-TOI. This was expected to be available by 2012, superseding the AES-2006. It comes with ambitious claims that it can be built in 40 months and will be "25% cheaper", presumably a reference to the cost of the AES-2006. However, so far, no orders for the design have been made.

Nonetheless, it was the completion of the AES-2006 design that saw the emergence of the Russian nuclear industry on to the world stage. Forecasts of two to three orders per year for the home market quickly proved unrealistic and only five domestic orders for the AES-2006, including two each for the Leningrad and Novovoronezh sites, have been placed, the most recent starting construction in 2010. A fifth order started construction in the Russian enclave of Kaliningrad, but was stopped in 2013 and appears unlikely to proceed.

Russian export orders
Only two export reactors, both for Belarus, have started construction, but there is a long queue of countries with firm orders or nearly firm orders for about 30 reactors.

The first, in 2010, was a deal with Turkey to supply four reactors, including a major ownership stake by Russia with most of the power sold at a fixed real price of about $120/MWh. Construction on the first reactor was expected to start in 2011, but, in 2015, it still appears at least a year away. The ownership details of the consortium and other issues, including the pricing of Russian gas imports to Turkey and the possible construction of the TurkStream gas pipeline, remain to be resolved.

EPR AND AP1000 EXPERIENCE

Plant	Country	Design	Construction start	Construction completion at construction start	Forecast construction completion
Olkiluoto 3	Finland	EPR	May-05	May-09	Late 2018
Flamanville 3	France	EPR	Dec-07	May-12	>2018
Summer 2	USA	AP1000	Mar-13	Mar-16	Jun-19
Summer 3	USA	AP1000	Nov-13	Nov-18	Jun-20
Vogtle 3	USA	AP1000	Mar-13	Apr-16	Q2 2019
Vogtle 4	USA	AP1000	Nov-13	Jan-18	Q2 2020

Source: World Nuclear Industry Status Report 2015

RUSSIA'S FIRM NUCLEAR EXPORT ORDERS

Country	Year	Firm orders	Start or initially expected start of construction	Long-term target
India	2009	Kudankulam x 2	2010 (not started)	12-14 reactors
Turkey	2010	Akkuyu x 4	2011 (not started)	
Vietnam	2010	Ninh Thuanh x 2	2014 (not started)	
Bangladesh	2012	Rooppur x 2	2012 (not started)	
Iran	2014	Bushehr x 2	2015 (not started)	8 reactors
Finland	2014	Hanhikivi	2017	
Hungary	2014	Paks x 2	2018	
Jordan	2015	Azraq x 2	2016	

Source: author

Deals followed with countries such as Vietnam and Bangladesh and, by 2015, Russia claimed firm orders for at least 17 reactors in eight countries, while deals are said to be close in another half a dozen countries.

There was also speculation that Russia would try to break into the developed country market using the UK as its bridgehead, but the imposition of sanctions relating to the conflict in Ukraine have put this option on hold.

The AES-2006 has not been reviewed in detail outside Russia, so it is not clear whether it would be licensable without significant modification by an experienced, open and transparent nuclear regulatory body.

For some time, construction appeared to be progressing relatively smoothly at Novovoronezh and Leningrad, with the exception of a serious failure in the containment wall at Leningrad in 2011. However, by 2014, the plants were not in service a year after the expected completion date for the first units, and a report by Russia's Audit Chamber revealed that the plants were actually at least three years late. By 2015, the plants were four to five years late.

There is little reliable information about the causes of the delays. Russian sources tend to emphasize a shortage of funds, low electricity demand growth and the life extension of existing plants on the same sites, rather than technical issues. The Belarus plants, started in 2013, still appear to be on time, although Rosatom has said that because the contracted price was denominated in dollars, the decline in value of the ruble means Belarus will have to pay 70% more than anticipated.

After a period of about ten years when it averaged one order per year, it is hard to see how Rosatom could manufacture the equipment for five or more reactors per year. However, it is the financial side that is most in doubt.

The order for Finland is clearly a high priority as it is seen as a gateway into the West European market, including the UK. Finance for the project is coming from the National Wealth Fund, but that is likely to be the only project able to access this limited resource. International sanctions and the fall in oil price have led to the ruble more than halving in value against the dollar. This has so depleted Russia's currency reserves that the central bank is no longer defending the currency.

Chinese ambitions

China is a much more recent entrant into the civil nuclear sector. It starting construction of its first civil reactor, a 300 MW PWR, and ordered two 900 MW reactors (Daya Bay) from the French company, Framatome (subsequently Areva), in 1985. Framatome's partner in this venture was the newly-created China Guangdong Nuclear Company (CGN), renamed China General Nuclear in 2014 to reflect its global ambitions.

MARKETS WITH ADVANCED NEGOTIATION

	Date of agreement	Sales target	Site
Armenia	2010	1	Metzamor
Venezuela	2010	2	
Egypt	2015	2	
Nigeria	2015	4	
Argentina	2015	1	Chihuido
Kazakhstan	2015	1	Kurchatov
South Africa	?	6	
Saudi Arabia	?	8	

Source: author

For the next ten years, there was little apparent sign of China's nuclear ambitions. No further construction starts occurred until 1996, but then, in the decade to 2006, 11 reactors started construction. These were made up of four more reactors from Framatome, three using a Chinese 600 MW design, two from Russia and two Canadian Candu reactors.

Two nuclear vendors, both licensed to Framatome/Areva, were emerging; CGN and the longer-established Chinese National Nuclear Corporation, a company that proudly claims to have brought nuclear weapons technology to China. Between 2007-2010, there was a huge burst of new orders, and 26 construction starts in only four years, 18 based on the design supplied for Daya Bay, most of which were supplied by CGN rather than CNNC.

However, China recognized that this design, which dates back to the late 1960s, was too old and looked to import and indigenize one of the latest designs offered. In 2007, it chose the AP1000 (Haiyang and Sanmen) over the EPR and ordered four reactors, with the expectation that the AP1000 would become the main design used in China. As back-up, two EPRs (Taishan) were also ordered by a joint venture of CGN and the French utility EDF.

To indigenize the AP1000, a third vendor was set up, the State Nuclear Power Technology Company. The three Chinese vendors all set about producing their own advanced technologies developed from those offered by their partners. CNNC and CGN based their designs, ACPR1000 and ACP1000 respectively, on Areva designs, while SNPTC used Toshiba/Westinghouse technology for its CAP1400.

The ACPR1000 and the ACP1000 are significantly smaller than the EPR, while CAP1400 is a scaled up AP1000. The Chinese government tried to rationalize the industry structure in 2013 by forcing CNNC and CGN to 'merge' their designs to form the Hualong One (HPR1000) design. While the HPR1000 now exists, CNNC and CGN have their own versions, which they promote separately.

2011 was a watershed for the Chinese nuclear industry with ordering coming to an abrupt halt overtly because of the impact of the Fukushima disaster in Japan. However, the strains of expanding their nuclear industry so rapidly may have been telling and it was becoming clear that the AP1000 and the EPR were too expensive to base a large program of reactors on.

Ordering slowly began again in 2012 and in the period 2012-15, 11 construction starts were made, four using the old CPR1000, four using the CGN ACPR, two using the Russian

AES-92 and, in May 2015, the first HPR1000 reactor (supplied by CNNC) started construction. The CAP1400 awaits its first construction.

Chinese export orders

China's only success in export markets is in Pakistan, where CNNC has supplied four 300 MW PWRs, two of which are still under construction. In 2013, CNNC announced it would also build two ACP1000s in the country. Work has yet to start on these, and it now seems likely the HPR1000 design will be used. CNNC also has hopes of orders from Argentina, Brazil and Algeria, although none of these are close to done-deals yet.

CGN is going for a more ambitious strategy targeting developed country markets with the UK Bradwell project announced in 2015 as its shop window. Here it will partner EDF, as it has for Taishan and will do for Hinkley. Realistically, hurdles such as obtaining consents and design approval mean construction on Bradwell is not going to start much before 2025, if ever, so this is a long and risky game.

Other target markets for CGN, like Kenya, look highly problematic. CGN is also using the expertise it gained from owning and operating two Candus in China to bid to build two Candus in Romania. SNPTC is a little behind the other two, although construction start of the first CAP1400 in China is expected this year. Target export markets for CAP14000 are South Africa and Turkey although deals are not close in either case.

Domestic delays

For a long time, Areva and Toshiba/Westinghouse consoled themselves that while construction of their new designs was not going well elsewhere, experience in China showed that they could be built to time. However, in February 2014, in a presentation to the International Atomic Energy Agency, a Chinese official acknowledged that the 26 reactors that started construction between August 2007 and December 2010 were all behind schedule, with the longest delays, more than two years, at the AP1000s and EPRs.

For the AP1000s, there has been an ongoing issue with the reactor coolant pumps. These failed acceptance tests in 2011, were modified, but failed again in 2014. They were modified and re-shipped in mid-2015, but it remains to be seen whether the problem has actually been resolved.

For the EPRs, there was no specific reported issue behind the delays although Chinese officials are clearly frustrated that Taishan appears to have overtaken the EPR's first construction start in Finland, Olkiluoto, and the first EPR being built in France, Flamanville, imposing first-of-a-kind testing requirements on China.

However, in March 2015, the French safety regulator stated there were serious flaws with the reactor vessel bases and lids manufactured by Areva for Taishan, Flamanville and for three reactors yet to be ordered, including the Hinkley Point project. The parts for Olkiluoto were made by a different supplier and are not affected.

No decision by the French safety regulator on whether these flaws are so serious as to prevent operation is expected before second-half 2016. It is highly unlikely that the Chinese regulator will not follow the French regulator's decision.

At best, the parts will be deemed acceptable and there will be no further delay. Alternatively, they could require repair or replacement, requiring a significant part of the existing construction to be removed and leading to much longer delays and higher costs. In a worst case scenario, the cost of repairing or replacing them could be prohibitive and the reactors abandoned.

Regulation

For both Russia and China, a major uncertainty is the capability, rigor and independence of their respective national safety regulators and how the vendors would cope with the demands of an open, transparent and experienced regulatory body.

For Russia, a Rosatom official stated that the official licensing document "is a short piece of paper, since the memos are, in the regulator's view, the property of whoever has paid for that work and in Russia that is Rosenergoatom, Rosatom's nuclear power plant operator subsidiary".

CONSTRUCTION DELAYS AT AES-2006S

Plant	Construction start	Construction completion at construction start	Forecast construction completion at March 2015
Leningrad 2-1	October 2008	2013	2018
Leningrad 2-2	April 2010	2015	2020
Novovoronezh 2-1	June 2008	2013	2017
Novovoronezh 2-2	July 2009	2014	2019
Belarusian 1	November 2013	2018	2018
Belarusian 2	April 2014	2020	2020

Source: World Nuclear Industry Status Report 2015

DELAYS AT CHINA'S AP1000S AND EPRS

Plant	Construction start	Construction completion at construction start	Forecast construction completion
Taishan 1	November 2009	February 2014	2018
Taishan 2	April 2010	August 2014	2018
Sanmen 1	April 2009	August 2013	Mid-2016
Sanmen 2	December 2009	August 2014	June 2016
Haiyang 1	September 2009	May 2014	March 2016
Haiyang 2	June 2010	February 2015	September 2016

Source: World Nuclear Industry Status Report 2015

This is not going to be acceptable in Europe or the United States and ought to raise issues in developing country markets. The requirement for a fully worked-out and frozen design for regulators to review means the apparent constant fiddling with design that seems to afflict all reactor vendors will not be acceptable.

For China, there are serious concerns about how stretched the regulator is. In 2015, the regulator was overseeing construction of 21 reactors, operation of 31 reactors and was carrying out first-of-kind safety reviews for six reactor designs. The French safety regulator has raised particular concerns, saying: "Unfortunately, collaboration [with China] isn't at a level we would wish it to be. One of the explanations for the difficulties in our relations is that the Chinese safety authorities lack means. They are overwhelmed."

Revival outlook

Despite accounting for the vast majority of reactor orders in the past decade, the Russian and Chinese nuclear industries remain inexperienced in countries outside their strong sphere of influence and have little experience of dealing with tough, open, independent regulatory bodies.

Getting safety approval from a regulator requires much more than a 'tick-box' approach and increasingly requires an exhaustive process of designing and specifying every nut and bolt. This is a process that even experienced vendors like Areva and Toshiba/Westinghouse are struggling to come to terms with. In developed country markets, there is also distrust of too heavy a dependence on Russia and China for such a sensitive technology, as well as concern about the military connections of their suppliers.

New developing country markets for nuclear power, especially those with no previous experience with nuclear power, have more often than not come to nothing. In addition, with real nuclear costs continuing to escalate and the problems of finance getting correspondingly worse, there is every reason to believe things will not change. It would be no surprise if much of Russia's order book evaporates.

There are no reliable estimates of the cost of Russian and Chinese reactors and none are likely until they compete in open markets. The previous forecast nuclear revival, that occurred around 2000, was based on a promise of construction costs of less than $1000/kW of capacity. The latest cost for the UK's Hinkley Point project equates to about $8500/kW.

It is hard to see how Russia can offer reactors with comparable safety systems significantly cheaper than that. The limited evidence there is from Finland suggests that Rosatom's prices will differ little from those of Areva or Toshiba/Westinghouse.

China's costs may be a little lower, but given that most reactor projects are based on at least 50% local content, this advantage will be diluted in export markets. In terms of supplying finance, China also appears to be in a much stronger position than Russia, given the depletion of Russia's foreign currency reserves and low oil prices.

Russia's strength is in its long track record of independently developing reactor technology, while China has so far only proved that it can copy Western technology. Whether it has a strong independent design capability remains to be seen.

Wind offers new energy pathway for Uruguay

Uruguay's wind power boom offers new options for its energy future, based on a diversified low carbon generation mix of hydro, wind, solar and biomass, one perhaps strong enough even for the electrification of transport. But the country is still exploring for oil and gas. Uruguay is looking at two very different energy pathways; the question, perhaps, is whether there is space for both. **Charles Newbery**

Having been left short of energy by a failed bet on Argentinean natural gas imports in the early 2000s, a wind power boom in Uruguay is now fueling potential for a diversified low carbon energy mix that is increasingly less reliant on imported fossil fuels. Wind power is already meeting an average 30-35% of electricity demand, among the highest rates in the world, and, in the last two years, the country has moved from electricity importer to exporter.

"We have a goal of getting 50% of our primary energy from renewable sources," said Olga Otegui, director of the country's National Energy Department. "We already surpassed that target in 2014, with a 55% share."

A small, mostly flat country, Uruguay has the second best wind power conditions in South America after Argentina. Uruguay has pursued economic stability, legal security and favorable business conditions and, as a result, its wind sector is flourishing. By contrast, Argentina's remains largely undeveloped.

Uruguay's wind power capacity has surged from 52 MW in 2013 to 600 MW in 2014 and 850 MW in 2015. It is on track to reach 1 GW in 2016 and 1.4 GW in 2017, when it will account for more than a quarter of the country's total installed generating capacity. Uruguay has also brought 400 MW of biomass capacity online, which it plans to increase by

20-60 MW, while solar photovoltaic capacity is expected to rise to 220 MW in 2016.

Uruguay did not set out to build so much wind capacity, but the prices offered by investors proved irresistible when set against the cost of imported electricity. At its first tender in 2010, the government received bids for $83/MWh in power purchase agreements for a total of 150 MW. A year later, it got $63/MWh for another 150 MW, far less than the $350-400/MWh the country had been paying for imported electricity from Argentina. “The low prices made the government rethink its strategy and say, “Let’s go for it,’” said Fernando Schaich, president of the Uruguayan Wind Energy Association.

Maxed-out hydro

Until wind, Uruguay’s strategy had been to add thermal power capacity as a backup for hydropower, the potential for which has been fully exploited since the 1970s, when the last large dams were built. These dams provided the country with 100% of its electricity in the 1980s, until droughts and demand growth exposed weaknesses in the system.

The government sought gas imports from Argentina to feed combined-cycle plants, replacing diesel and fuel oil, to safeguard the system during times of low water flow. It built a 5 million cubic meter per day gas import pipeline under the Rio de la Plata to bring in supplies, and gas started to flow in November 2002.

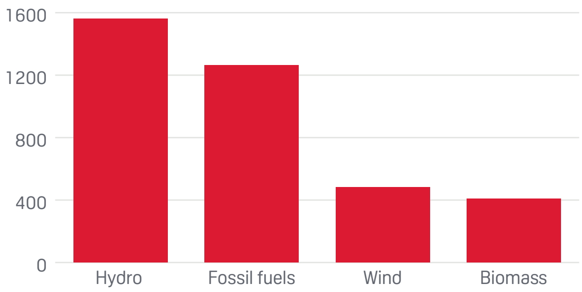
The plan made sense initially. Argentinean gas production had nearly tripped between 1990 and 2004, hitting a peak of 143 MMcm/d that year, which allowed Argentina to export an average of 20 MMcm/d of gas in the 1990s and early 2000s, mostly to Chile.

However, Argentina’s economic collapse in 2001/02 led to a cutback in drilling. Production plunged, but a recovering economy and subsidized gas prices pushed up demand. This brought shortages, and Argentina responded by redirecting gas exports to the local market, reducing the flow through the Rio de la Plata pipeline to a trickle.

Policy shift

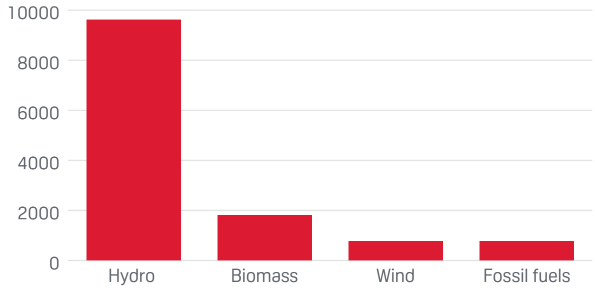
When Broad Front, a center-left coalition, won the Uruguayan presidency for the first time in 2005, it started to shift energy policies, first under Tabare Vazquez and then under Jose Mujica. “A significant wing of the party is very

URUGUAY: INSTALLED ELECTRICTY GENERATION CAPACITY, 2014 (MW)



Source: Ministry of Industry, Energy and Mining

URUGUAY: ELECTRICITY GENERATED BY SOURCE, 2014 (GWh)



Source: Ministry of Industry, Energy and Mining

eco-friendly, and it is politically popular to pursue renewable energy resources,” said Mark Jones, an expert on Latin American politics at Rice University in Houston, Texas.

Vazquez, who is president again from 2015-2020, said in November that his administration would continue to build up renewable energy capacity as part of a 2005-30 energy plan approved during his first term of office. The plan created a roadmap for pursuing energy security on all fronts, by installing renewable power capacity, diversifying energy imports, developing domestic oil and natural gas resources and reducing electricity consumption with efficiency and new technologies.

A key aim has been to reduce imports of crude, diesel and fuel oil, which met 45% of the country’s total energy needs in 2014, and to achieve carbon neutrality by 2030, including through the use of hybrid and electric buses and cars. “Uruguay almost doesn’t have to turn on power plants with oil anymore,” Vazquez said. “And it doesn’t have to look to the sky to see if it rains so the dams can generate electricity.”

Diversification

At end-2014, the country had 3,719 MW of installed generation capacity, according to the Ministry of Industry, Energy and Mining. Of that, 42% was hydro, 34% fossil fuels, 13% wind and 11% biomass. In terms of primary sources, 44% of the country’s energy needs were met with oil and derivatives in 2014, 25% with biomass, 18% hydro and wind power, 11% with firewood and 1% with Argentinean gas.

Foreign investment has been the driver behind the increase in renewable capacity, with more than $7 billion flowing into projects since 2013. This investment has been attracted by Uruguay’s economic stability. After the economy collapsed in 2001-02 in parallel with Argentina, its main trading partner, Uruguay set out to improve fiscal and trade accounts, restructure debts, attract foreign direct investment and diversify industry and exports. The effort allowed it to regain its investment grade status in 2012.

In contrast, Argentina still hasn’t settled about 7% of the debts from a $100 billion default in 2001, leaving it locked out of global capital markets. This has saddled it with high interest rates and little financing, a turnoff for investment in its energy sector, despite the country’s huge unconventional oil and gas resources and vast wind potential. Uruguay has "a reputation of legal certainty and this builds investor confidence," said Jose Pou, director of XDT Ingeneria, an energy-consulting firm in Montevideo.

The return to global financial markets could not have been more opportune, given the low level of interest rates, which made it easier and cheaper to finance projects in Uruguay. At the same time, costs for onshore wind have fallen significantly as more wind turbine manufacturing capacity has come online around the world. "Without low interest rates and legal certainty, the boom wouldn't have happened," like it hasn't in Argentina, Pou said.

Fossil fuels

However, there are still plans to back-up the country's renewable energy base with fossil fuels, although it is not yet certain how the success of wind will affect these plans. "Our bet is to try to complement renewables with natural gas," said Otegui, adding that how do this is still under discussion.

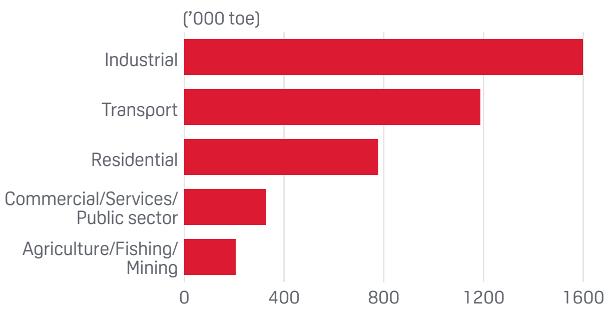
When the gas flow from Argentina dried up, Uruguay looked to LNG imports. The government set out in 2013 to build a $1.1 billion floating regasification terminal in the Port of Montevideo. Project progress has not been smooth and, in November, Vazquez said changes could be made in response to the increased availability of wind power.

One possibility is to reduce the size of the terminal, which was originally to have send-out capacity of 10 MMcm/d, expandable to 15 MMcm/d. While the country still consumes 300 Mcm/d of gas from Argentina, the terminal could supply about 5 MMcm/d to replace diesel and fuel oil use in power generation, as well as provide gas for cooking, heating and industry.

Another 4-5 MMcm/d could be sold to Argentina, which still has a 25% gap between its own production and demand, which it currently meets by importing gas from Bolivia and LNG from international markets.

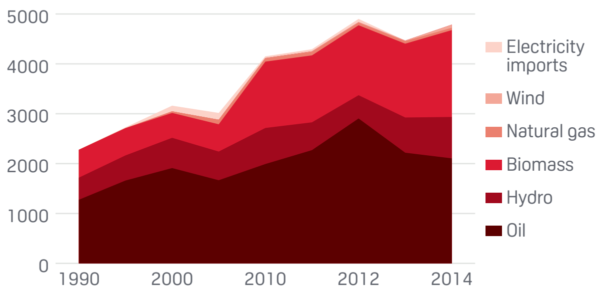
However, Vazquez has warned that Argentina is not a reliable partner. "If we were convinced that our neighbor would buy the surplus, then things would be different," he said. "But there's no security of that." Argentina had originally promised to become a partner on the project, but has since fluttered in and out of its commitments.

URUGUAY: FINAL ENERGY CONSUMPTION BY SECTOR



Source: Ministry of Industry, Energy and Mining

URUGUAY: ENERGY SUPPLY BY SOURCE ('000 toe)



Source: Ministry of Industry, Energy and Mining

Another headache stems from project delays. In February, Brazilian construction company Constructora OAS pulled out of a contract to build a breakwater and wharfs for the terminal, citing financial problems. Then a consortium of France's GDF Suez and Japan's Marubeni quit as the builder and eventual operator of the terminal, paying a $100 million fine and likely delaying the start of deliveries until 2017.

XDT's Pou said that a possible reason for the Suez-Marubeni's exit was the terminal's location in the shallow Port of Montevideo. A better option, he said, would be to dock it in the deeper water ports of the Atlantic, allowing deliveries of larger cargoes in line with the industry trend.

On November 17, Uruguayan Minister of Economy and Finances Danilo Astori began talks with Japan's Mitsui OSK Lines, the builder of the regasification unit, on possibly modifying the project to take into account lower-than-expected gas demand. "When we started this idea, the energy from renewable resources was much lower than it is now," Astori said.

Another option for getting gas supplies – but also again for doubting Argentina as a market for exports – is that Argentina may be able to rebuild a domestic surplus of gas on the back of its large unconventional gas resources. "That would be much cheaper for Uruguay than the LNG option," Jones said, adding that Uruguay would then be able to alternate between Argentinean and LNG imports, based on the best price.

"But given the unreliable nature of Argentina as a supplier, the LNG terminal is a smart move to provide Uruguay with a level of energy security." It is also expected that it will take Argentina at least a decade to rebuild its gas production to a level where it could again sustain exports, according to Francisco Mezzadri, an energy consultant in Buenos Aires.

Oil and gas hedge

Another not so green strand in Uruguay's push for energy security is oil and gas exploration. In May, state oil company Ancap said onshore gas resources could be extracted easily from depths of between 1,500 and 2,000 meters in the country's northwestern Norte Basin. Australia's Petrel Energy, which is exploring in the region, said that certification by US oil and gas consultants Netherland, Sewell and Associates suggests that the Piedra Sola and Salto blocks could contain 1.769 billion barrels of oil and gas.

Further studies have shown that the resources are 60% oil and 40% gas, meaning that the gas resource could equate to as much as 3.1 Tcf, which, if developed, could produce 0.5-2.0 MMcm/d, according to Ancap.

Dallas-based Schuepbach Energy International, which is majority owned by Petrel Energy, has plans to drill four wells in first-quarter 2016, two on Piedra Sola and two on Salto. France's Total is also next year expected to drill Uruguay's first offshore well in 40 years in partnership with ExxonMobil. They will invest between $160 million and $200 million to drill in waters 3,400 meters deep.

Uruguay has no proven oil or gas reserves, but the government has said its offshore geology could be similar to basins in Brazil and Namibia. The potential has attracted BG Group, Repsol and others to take a shot at finding resources.

Electric alternative
The surge in wind power generation has meant Uruguay has been able to switch from electricity importer to exporter over the past two years, using its existing 2 GW interconnection line with Argentina and two interconnections with Brazil, one of 70 MW capacity and the other with 500 MW.

"This is another line of business for us," Otegui said. "We have the wind and the parks, and it is good for the system and for generators to export the surplus energy because otherwise there is a risk of having to close parks if there is not enough demand."

Domestically, the government has added transmission capacity to handle the increased wind generation, including loops attaching the wind parks to the hub-and-spoke designed network. Schaich of the Wind Energy Association said the electricity dispatch center has figured out how to handle all the wind power without too much fossil fuel backup. This could mean that the country won't need gas in the near term, but could rely on diesel, including at a 520 MW combined-cycle plant now under construction, he said.

The grid can switch to hydro as needed, tapping into water reservoirs when winds die down, and then use fossil fuels as a backup for times when either is lagging in output.

Schaich expects that the addition of more biomass, wind and solar power will allow Uruguay to meet its electricity demand comfortably through 2019-20, after which there will be room to add 100-150 MW of wind capacity per year.

The government is also looking at pumped hydro for load balancing, so that when there is plentiful wind excess generation can be used to pump water from lower to higher hydro reservoirs for use when there is less wind and solar output.

"Uruguay is considering this closed, efficient system for the next 10 years," as well as smart grid technology and charging electric cars at night, when there can be excess energy if winds are high. "The combination of water-pumping units, smart grids and electric transport could be the future of Uruguay," Schaich said. "We don't have oil, and so we have to import all of our fuel. It is not a matter of whether it is better for Uruguay. It is the only way."

Power and gas price linkage dissolves

Power and gas prices in EU markets now operate in separate universes. Wholesale power prices are increasingly determined by low or zero fuel cost forms of generation, while gas prices reflect growing market globalization and convergence between key price anchors. Despite oversupply, gas will struggle to price itself back into EU power markets. **Ross McCracken**

Continental European clean spark spreads have remained stubbornly negative for a number of years, although there are some signs of improvement. The clean spark spread shows the profitability of burning gas for power generation based on a 50% efficient gas plant, taking into account the costs of buying emissions allowances on the EU Emissions Trading Scheme.

By contrast, dark, clean spark spreads, which indicate the profitability of 35% efficient coal-fired generation plant, in continental Europe, have remained positive. In the UK, both spreads have been broadly positive, but coal burn has been much more profitable than gas. Considering that gas plants emit roughly half the CO_2 emissions that a coal plant does for the same power output, this is hardly a positive outcome in terms of EU environmental policy.

Given these pricing signals, it would be logical to assume that investors would be drawn towards investment in new coal plant and deterred from investment in gas-fired generation capacity. However, in reality, they are being deterred from both.

Shrinking market
EU electricity demand has never recovered from the global financial crisis of 2008/2009. Total EU electricity generation peaked at 3392.2 TWh in 2007 and has fallen for four consecutive years, reaching 3166.0 TWh in 2014, a 6.7% drop from 2007.

In the same period, electricity generation from renewables, including hydro, has increased from 1456.8 TWh to 1771.3 TWh. Even when the decline in nuclear generation is factored in there is a gain in low carbon electricity generation of 314.5 TWh, compared with a decline in total generation of 226.2 TWh, which means the implied loss to fossil fuel-fired generation is 467.6 TWh, a decline of 27.9%.

Both coal and natural gas markets face substantial over-supply, a function of cyclical over-investment in both industries and the unexpected disappearance of demand growth in some but not all markets. Both energy commodities have seen prices fall sharply, which would normally be expected to restore to positive territory the margins represented by the spark spreads.

However, coal prices have fallen further than natural gas. 6,000 kcal/kg, 90-day thermal coal sold on a CIF basis in the Amsterdam-Rotterdam-Antwerp area has dropped from about $100/mt at the start of April 2012 to $54.85/mt in early November, a drop of 45%. By contrast, month-ahead gas at the Dutch TTF has fallen 27.9%, from €24.75/MWh to €17.85/MWh over the same period.

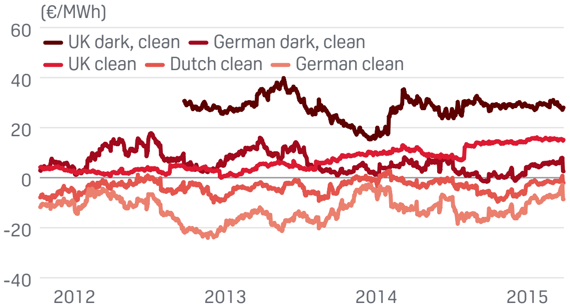
Moreover, wholesale power prices in Europe have fallen. In August, German wholesale electricity prices dropped to their lowest level in almost 12 years, owing to increases in renewable generation and falling wholesale prices for coal and natural gas. The forward curve for German power suggests this the price decline will only get worse.

Low fuel cost generation mix

The build-out of renewables, grafted on to substantial existing nuclear and hydro capacity, has changed the capital cost structure of the power generation fleet and its exposure to fuel costs. Wind and solar power generation costs are largely a function of the cost of initial investment, as is hydro and to a large extent nuclear. In terms of marginal cost, electricity generated by these sources is very cheap.

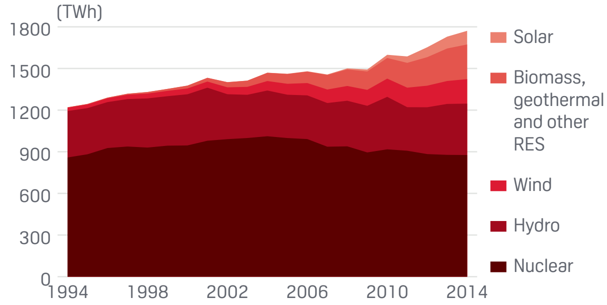
Europe continues to add renewable capacity to a market with declining demand. This can be done because the investment case for renewables has not been based on wholesale power prices, but on Feed-in-Tariffs and other

EUROPEAN SPARK SPREADS - CLEAN 50%, DARK 35%



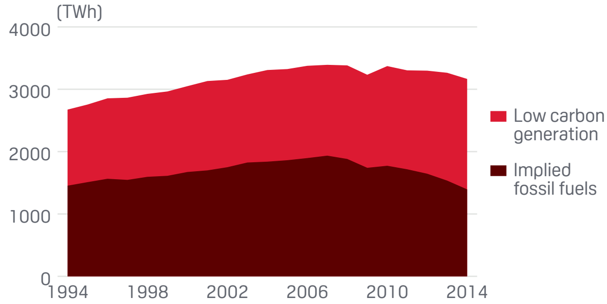
Source: Platts

GROWTH IN LOW CARBON ELECTRICITY GENERATION



Source: BP Statistical Review of World Energy 2015

DECLINING MARKET FOR FOSSIL FUELS



Source: BP Statistical Review of World Energy 2015

forms of subsidized regulatory support that have a broad dispensation from state-aid rules on the grounds that it is necessary to meet emissions reductions targets.

There is no way that a generation technology where fuel costs make up a substantial proportion of marginal costs can compete. The more must-run, low-marginal-generation-cost, capacity is added to the system, the less wholesale power prices will reflect fossil fuel costs and the more they will reflect the low operational costs of renewables, nuclear and hydro.

The EU has plans to bring renewables into the market, but even this is unlikely to change the fortunes of gas-fired plant operators. Existing renewables capacity, built with subsidies, will continue to operate, its capital costs effectively amortized by the subsidies already received. Even if no subsidies are provided for new renewables, onshore wind is now competitive with coal and gas and will continue to be built, adding more must-run low marginal cost generation.

Coal versus gas

This situation effectively leaves natural gas in competition with coal-fired generation for a declining share of the market. It also represents a dismissal or neglect of the role that natural gas could play in the transition to a low carbon economy. This role at present is evolving despite EU energy policy rather than because of it, but there is no certainty of success.

In a race to the bottom based on the marginal cost of electricity generation, coal is likely to win out over gas. When compared against gas-fired generation, the ratio of capital to fuel costs favors coal. Coal plant is generally more expensive to build per MW of installed capacity, but the fuel costs of running the plant are generally lower, and have become more so as coal prices have fallen further than those for gas.

Operational characteristics also have to be taken into account. Coal-fired plant runs on a thermal cycle only and is best run continuously, making it a price taker in wholesale markets. The open cycle of gas-fired turbines means they can be used as peaking plant, but even here they face competition from pumped hydro, solar and, increasingly, other forms of storage.

Solar generation may be variable, but it is also nicely aligned with the day-time peak in electricity use. According to the Fraunhofer Institute for Solar Energy Systems, peak-hour prices in Germany in 2008 were €14/MWh above baseload prices. By 2013, they were just €4.36/MWh above, a historical low. The introduction of renewables has reduced gas-fired plants' ability as the marginal power producer to capture those spikes in price caused by peaks in demand.

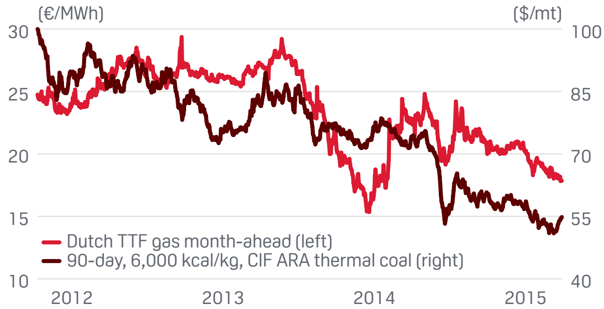
Carbon penalties

As a result, gas can only compete with coal, if there is regulatory intervention based on emissions. And even then it will be competing for a declining share of the market. This intervention can be either positive (incentivizing gas) or negative (penalizing coal).

The EU Emissions Trading Scheme has been in place for almost a decade, but it is a project that has proved almost wholly ineffectual. The price of carbon allowances has been far too low to stimulate investment in low carbon technologies and, more than once, prices have crashed near to zero, trashing investor confidence in its future potential.

Hopes for the ETS are now pinned on the introduction of the Market Stability Reserve, which will be introduced from January 1, 2019. The MSR will remove 12% of the overall surplus of allowances each year, if the surplus is above 833 million mt, and release 100 million, if the surplus falls below 400 million mt. The EU also decided to transfer 900 million mt directly into the reserve rather than return them to the market in 2019 and 2020 as previously planned.

EUROPEAN GAS VERSUS COAL PRICES



Source: Platts

PLATTS GERMAN TWO YEAR AHEAD PRICE ASSESSMENTS, MONTHLY AVERAGES (€/MWh)

Source: Platts

The aim of the reform is to provide a mechanism for adjusting supply based on underlying demand, in effect a means of addressing situations like the global financial crisis, in which a downturn in economic activity in the EU produced a huge surplus in carbon allowances and thus low prices and no incentive to switch from coal to gas or invest in low carbon technologies.

However, it is by no means clear that the MSR reform will have the necessary impact. Moreover, even if it does, it will not affect EU allowance prices until around 2020.

The way the MSR is structured guarantees a permanent surplus, which must limit the price impact. Based on the minimum intervention level of 833 million ton, reductions of 12%, even if instituted year-after-year, would take six years to reduce the surplus to the point where the system would then actually start to top the surplus up. This creates a 'market' which can never be short of supply.

The ETS has from day one been riddled with political compromise and the MSR looks no different. The carbon price, it appears, cannot be allowed for political reasons to rise to levels where it would really incentivize gas burn over coal because of concern of the effect of high carbon allowance prices on other industrial sectors in the EU.

There are proposals to strengthen the system further post-2020, with a 2.2% reduction in the annual cap, compared with 1.74% currently, but even in this proposal 43% of allowances would still be allocated freely to sectors at risk of 'carbon leakage', which is carbon speak for shutting up shop and moving out of the EU altogether. This proposal, like the MSR, will be subject to lengthy negotiations likely to last around two years and could well be watered down.

The irony is that the EU is broadly on target to meet its renewables' targets regardless of the failure of the ETS. However, this is the result of other policies, most specifically subsidies for building renewable generation capacity. A further paradox is that the construction of renewables and consequent decline in gas plant utilization has reduced demand for carbon allowances, helping to maintain the surplus already in the system. Renewables subsidies do not allow the ETS to function as it should.

Regulation rather than market signals

As a result, neither wholesale electricity prices nor the carbon price represent meaningful market signals for coal and gas-fired plant operators. If gas plant operators are to receive regulatory help, they are dependent on national energy policies.

The UK has instituted its own carbon tax, the Carbon Price Support, which by directly penalizing emissions by a fixed amount has been instrumental in turning the UK clean spark spread positive, thereby providing a real incentive to burn gas rather than coal.

A number of EU countries have also implemented or are considering implementing capacity markets, which could provide an alternative revenue stream for some gas plant. But for the gas market, gas plant offering capacity only as a reserve does not imply a lot of gas burn.

With no obvious market incentives to invest in or even use gas plant, the gas industry has to hope that coal continues to be more heavily regulated against than gas on the basis that as coal plant is closed, gas will be needed to fill the gap. This assumes also that renewables do not grab coal's share of generation as well.

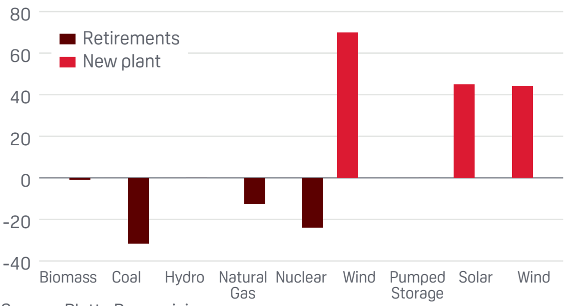
Coal plant is already more heavily regulated against as a result of the Large Combustion Plant Directive and its successor the Industrial Emissions Directive. New coal projects also attract intense environmental opposition, and there is the risk that new plant will suffer higher carbon prices under the reformed ETS and/or additional regulation at the national level.

New capacity

As a result, the number of new coal projects under construction has fallen, while many are scheduled to close. Since January 2014, 25.5 GW of new generating capacity has come on-line in the EU, compared with 13.7 GW of retirements, providing a net gain of 11.8 GW.

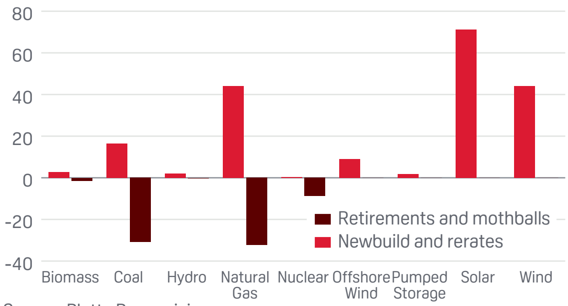
Of new capacity, wind has a positive addition of 8 GW and solar 6.8 GW. By contrast, coal-fired capacity has shrunk by a net 1.2 GW, with 6.1 GW of retirements and 4.85 GW of new additions, including cogeneration plants. There was also a net loss of just over 1 GW of plants that can use a variety of fossil fuels and a net loss of about 1 GW of gas-fired plant.

NEW PLANT UNDER CONSTRUCTION AND PLANNED RETIREMENTS TO 2023 (GW)



Source: Platts Powervision

EU: NEW BUILD AND RETIREMENTS 2010-2015 (GW)



Source: Platts Powervision

For new plants under construction, the picture is the same only more so. Out to 2023, the expected net loss of coal-fired generation plant across the EU is 23 GW and the net loss for gas-fired plant 5.9 GW.

In contrast, both wind and solar capacity are expected to continue to grow quickly. Data showing plants under construction does not provide a realistic picture in this time frame because solar projects are not captured as the data looks at only plants over 100 MW. In addition wind projects, particularly small ones, that could be generating by 2023 are not yet under construction.

Based on low construction rate forecasts from industry organizations Solar Power Europe and the European Wind Energy Association, likely cumulative additions between 2015 and 2023 are expected to amount to 70 GW of new wind and 45 GW of new solar.

On the loss side, nuclear plants closures will pick up pace towards the end of the forecast period. By 2019, Europe should see a net addition of just over 1 GW of nuclear capacity, but by 2023, based on current planned retirement schedules, it should see a net loss of almost 20 GW.

So in total about 43 GW of baseload generation (coal and nuclear) is set to be replaced by 115 GW of must-run variable generating capacity (solar and wind). Small additions of new biomass and hydro amount to just over 2 GW with a net gain of about 3.5 GW of pumped storage.

If gas-fired generation is to find additional space in EU markets, it has to hope that the decline in coal-fired generation and nuclear exceeds the gain in low carbon generation, not in capacity terms but in actual generation.

Another possibility is that the decline in baseload generation and increase in must-run variable will lead to a re-emergence of peak pricing, but this will be limited in terms of mid-day peaks by solar, in some countries by the increase in pumped hydro, and in others through the development and deployment of other storage technologies.

Myanmar election victory

The National League for Democracy's overwhelming victory in Myanmar's November elections represents a huge step on the road to democracy and the normalization of the country's relations with the rest of the world. It could create a new reality for those engaged with the country's plentiful energy resources, but both Myanmar and China still have good reasons to find a way of doing business. **Neil Ford**

With 25% of the seats in both houses of parliament set aside for military representatives, the opposition National League for Democracy had to secure an overwhelming victory in the November 8 elections to gain an overall majority. It did so, winning 390 seats to the governing Union Solidarity and Development Party's 42 on a turnout of about 80%.

This was far more than the 52.5% NLD secured in 1990 and the 66% recorded in the small-scale election of 2012. Crucially, it made enough inroads in the north of the country, where ethnic minorities such as the Wa and the Kachin predominate, to be sure of victory. The challenge from the hard line Buddhist Ma Ba Tha movement failed to materialize on the scale that many had feared.

President Thein Sein accepted the result and said of the transfer of power: "We will make sure it will be smooth and stable without having to worry about anything." The new president will be chosen by parliament.

Observers described the election as being reasonably fair and most of the election irregularities occurred in the run-up to the poll. The electoral roll was well out of date, with some voters entirely missing and deceased people included.

Ethnic minorities bore the brunt of exclusion, either because they are not considered to be citizens, such as the Muslim Rohingya, or because they live in border areas, which the Myanmar government in Naypyidaw considered too insecure to allow voting to go ahead.

Coup risk

The transition to democracy and end of military rule are far from guaranteed. The military pulled the rug from under the feet of the NLD in 1990, following another election that was won by NLD leader Aung San Suu Kyi. On that occasion, the NLD won 392 out of 492 seats.

After more than 50 years in power, the army will be loath to loosen the reins of power and another military coup cannot be ruled out. During the latter part of the election campaign, the military highlighted the chaos of Egypt, Libya and Syria following the Arab Spring, arguing that the people of Myanmar were better off with a military government and stability instead of greater personal freedom and the risk of much greater domestic violence.

The election results suggest that this argument was largely dismissed by the electorate, but it does provide the military with a narrative to support any attempt to regain power by force. As a result, Suu Kyi and the rest of the NLD leadership have repeatedly warned their supporters not to push for too much change too quickly and not to provoke the army by gloating. Violent street clashes could provide the pretext for the army, of even elements of it, to launch a crackdown on opposition.

Military governments are often viewed from the outside as monolithic structures with a single view, but they are as prone to cliques, division and disagreement as any other organization; it is merely that open dissent is often not tolerated. While the military hierarchy seems prepared to accept a transition to civilian rule, sections of it may oppose the change.

The NLD will not take power until end-January, providing plenty of thinking time for the generation of military leaders beneath that of Sein to contemplate what they could view as their stolen political inheritance.

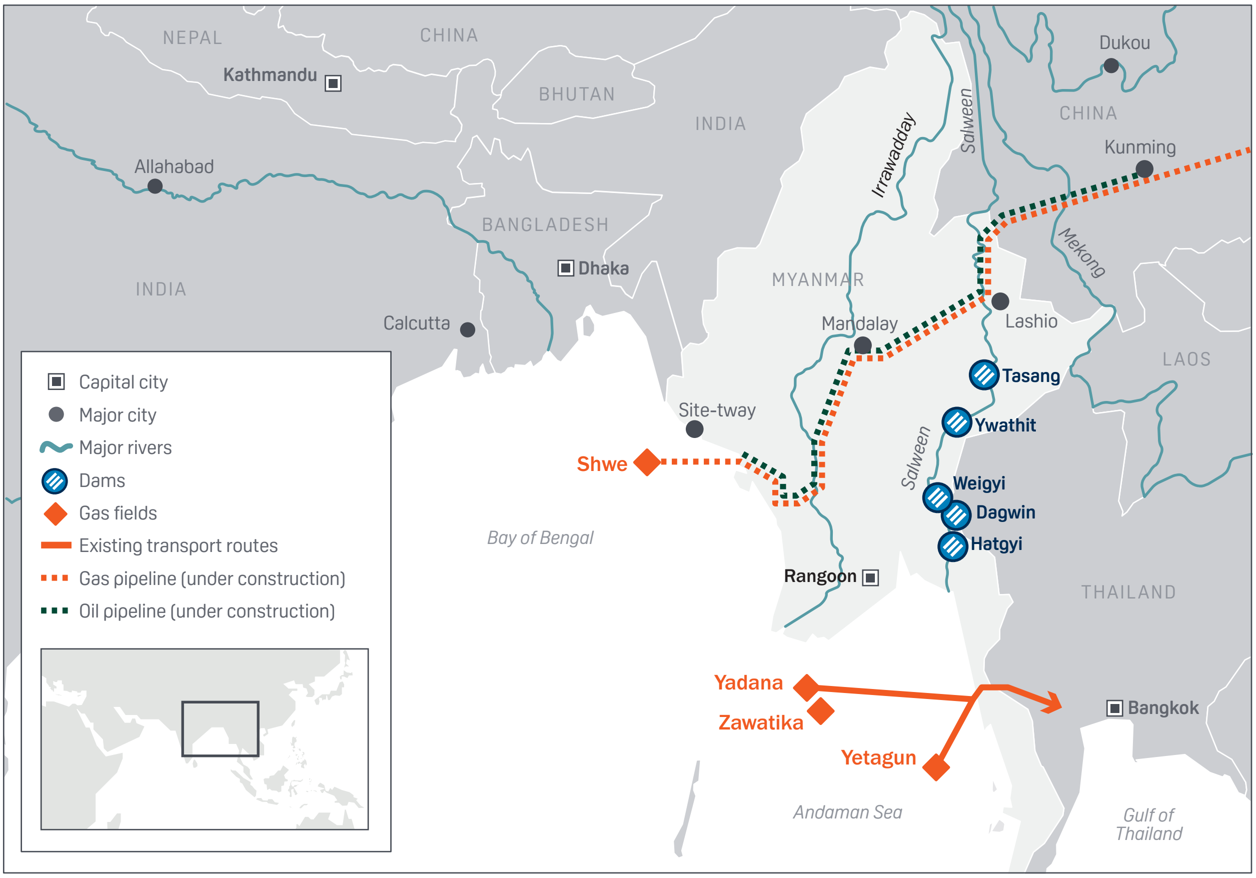
Nonetheless, while a coup is possible, the odds seem against it. The political process has been slow enough to allow for a transition in both power and mindset, while the pressure from abroad and within for change is enormous. Moreover, the army will retain a great deal of influence even when the NLD takes power, at least in the medium term.

It holds the right to veto any changes to the constitution, which itself retains a place at the heart of Myanmar's military power structures in what Sein describes as "a disciplined democracy". Apart from the automatically retained 25% of seats in both houses of parliament, the army will also control the ministries of defense, home affairs and border affairs, the ministers of which will be directly appointed by the head of the army, Min Aung Hlaing.

Thant Myint-U, a historian who advised the current government, commented: "The NLD are finally within striking distance of enjoying real governing power. There's a chance things could go pear-shaped over the coming few months, but if everyone's a little careful, and given that the army's powers are constitutionally protected, I think we're on track to see an NLD government come April."

The military could become uneasy if Suu Kyi exerts too much power. It specifically designed the constitution to block her from becoming president by banning candidates with foreign spouses or children, both of

MYANMAR'S OFFSHORE GAS FIELDS AND PIPELINES TO CHINA



Source: Platts

which applied to her. Once the new parliament takes over, it will choose a new president and a speaker, which may be Suu Kyi. She seems to have accepted – for now at least – that she will not become president, although she has openly talked of becoming the country's de-factor leader in interviews with the BBC.

The lower and upper houses plus the military representatives all put forward a candidate for president. The two who lose out become vice presidents as a form of consolation prize. This process may not be as important as previously thought, if Suu Kyi's power makes the presidency a largely ceremonial role. She said that her party will appoint a president who will "understand…perfectly well that he will have no authority".

Chinese realpolitik

Beijing had seen the writing on the wall by the start of this year. Suu Kyi visited Beijing for the first time in June in an effort to build relations with a Chinese government that she has criticized in the past. China's official news agency Xinhua stated: "China welcomes anyone with friendly intentions and it bears no grudge for past unpleasantness."

Chinese President Xi Jinping's willingness to meet her shows that Beijing is prepared to work with whoever is in power in Myanmar. China was a strong ally of Sudan before the secession of South Sudan in 2011, but once it became clear that the lion's share of oil reserves and production would be controlled by the new state, Chinese diplomats flocked to South Sudan to start negotiations.

Beijing's willingness to work with the military government in Myanmar could be taken as evidence of its desire to work with authoritarian regimes, but this is a slightly skewed interpretation. The Chinese government is prepared to work with any foreign partner, whether democratic or not, that can help it achieve its own aims. Authoritarian governments can sometimes be easier to work with because they can more easily deliver what they promise, but China would rather work with an effective liberal regime than an ineffective dictatorship.

When it sanctioned and funded the construction of the parallel oil and gas pipelines from Myanmar into China, as well as a number of other multi-billion dollar investments in the country, Beijing was aware that the military government could be replaced. Such pipeline projects are only developed when the operator is convinced that they will remain in operation for at least 20 years.

Myanmar is a key part of China's wider regional strategy, providing access for oil and gas, including imports that bypass the Strait of Malacca. It also provides port facilities that are – or will be – connected to China by modern road and rail links. Beijing therefore has a lot to lose, if Suu Kyi decides to ally herself too closely with the West.

In the same way, the new NLD government of Myanmar will deal with China. It needs to deliver on its promises to improve living standards for its people, provide more comprehensive health and education services, and ensure the development of badly-needed infrastructure.

These goals, more than greater openness with the outside world and greater freedom of speech, thought and religion, will determine its success. No matter who is in power in Myanmar, China is still the economic superpower and the source of greatest energy consumption in the region. The pipelines are already in place, so it is unlikely that any government would choose not to make use of them to generate revenue.

As always, there will be a number of obstacles to overcome. Apart from the cross-border fighting between rebels and Myanmar government forces, there is also the influence that Suu Kyi could have on China's own political dissidents.

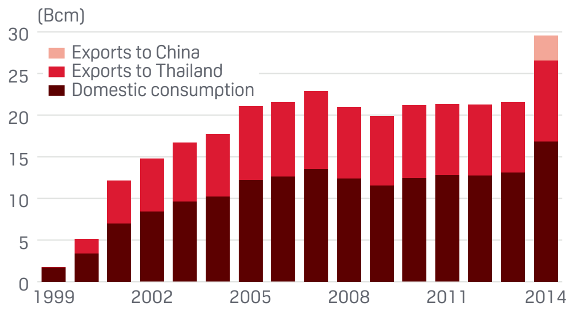
The biggest source of tension will not be the fact that she represents a democratically-elected government, but that Myanmar might set a model that some in China might wish to follow. Beijing does not want anyone else to influence its own political development. The Hong Kong press is already arguing that the election poses problems for Beijing, as a peaceful, orderly election was held after the Myanmar military granted only limited political freedom.

Border relations

In addition, relations between China and Myanmar's military government have not been as cosy as many observers have portrayed. The role of Myanmar's ethnic and religious minorities has been highlighted in international coverage of the election, but it is not the marginalization of the Rohingya that concerns Beijing. It is the fate of ethnic Chinese in the Myanmar half of the Sino-Myanmar borderlands.

Myanmar forces have fought for years against the Myanmar National Democratic Alliance Army, an ethnic Chinese group, in Kokang Special Region. Fighting has intensified since February, perhaps in anticipation of the army being reined in following the elections.

MYANMAR GAS CONSUMPTION AND PIPELINE EXPORTS



Source: BP Statistical Review of World Energy

Myanmar forces have chased MNDAA fighters across the border into China and shells have landed on Chinese territory. The border breaches have upset the Chinese, particularly as Chinese nationals have been killed in the fighting, but so too has the crackdown on ethnic Chinese people.

In response, Beijing has scrambled fighter jets, organized military manoeuvers on its side of the border and has warned of "firm and decisive action", if any further Myanmar offensives inflict damage on the Chinese side of the border. For their part, some in the Myanmar military believe that the Chinese military, or elements in it, are backing the Kokang rebels.

The fate of Myanmar's various minorities, concentrated as they are in the country's borderlands, is not just important for domestic stability, but also relations with China and other neighboring states. In terms of energy sector development, this makes them important for oil and gas pipeline projects and hydro schemes.

Voting was not held in seven areas with ethnic minorities where the lack of security was considered too big a problem because of the presence of armed militant groups, such as the Ta'ang National Liberation Army, the Arakan Army and the MNDAA. The pipelines to China traverse the states of Shan and Rakhine, both of which have been subject to armed uprisings. The fact that the minister of border affairs will be directly appointed by the military suggests that the army has not given up trying to find a military solution to political instability.

When either the NLD or the military government talk of minorities, they are not referring to tiny sections of the population. Of the 498 seats on offer in November's elections, 291 were in the majority Bamar-dominated south and center of the country, but a huge 207 were in what are regarded as minority states.

By the time the Rohingya are thrown into the mix, it is clear that the minorities comprise close to half of Myanmar's population, although the military disputes this. Regional parties had most success in the election in Rakhine in the west and Shan in the east, but the NLD was remarkably successful in the minority areas overall.

Energy sector investment

Myanmar could benefit indirectly from Chinese economic policy. Beijing has made clear its strategy of moving away from high volume, mass manufacturing and towards domestic consumption and low volume, high quality manufacturing. This may displace millions of jobs out of China and into other countries.

Vietnam and Bangladesh have already benefitted from rising labor costs in China, attracting millions of manufacturing jobs, but Myanmar is also well placed to take advantage of this trend, if it can develop a more open economy. There are currently greater restrictions on foreign investment in Myanmar than in China.

The rise of the NLD should also ensure that the thaw in relations between Yangon and the West, Japan and other industrialized nations, which began in 2011, speeds up. A democratic government in Myanmar should ensure the injection of development aid and greater foreign direct investment from Western firms, boosting living standards and consumption in the process.

At the same time, a more liberal political and economic operating environment may encourage much greater upstream investment. Current proven gas reserves of 10 Tcf are almost certainly a big underestimate of the country's real gas potential as so much territory has not been explored because sanctions and bad publicity have deterred many firms from investing.

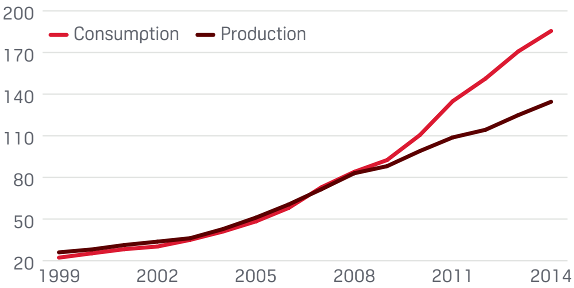
Suu Kyi will probably proceed with a host of planned and ongoing economic and infrastructural joint ventures between China and Myanmar, such as the planned railway between Yunnan Province and the Bay of Bengal, and the Kyaukphyu Special Economic Zone.

The latter was set up last year on Myanmar's Ramree Island as a joint venture between the governments of Myanmar and China. The zone will include an oil and gas terminal, with gas supplied to industrial concerns from the offshore Shwe gas field.

However, the new government will almost certainly pay more heed to environmental and human rights' concerns. The political thaw has already seen work on the Myitsone hydro scheme halted. With generating capacity of up to 6 GW, it was being developed by a consortium including China Power Investment Corporation to export electricity to China. Lack of consultation and huge opposition to the project saw it suspended in 2012. Similarly, the planned 4 GW Dawei coal-fired plant was cancelled because of opposition to the scheme on environmental grounds.

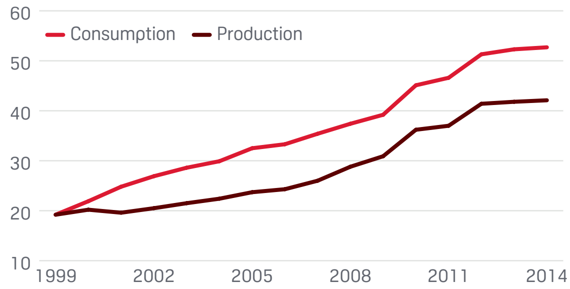
Securing the support of the World Bank, IMF and other international financial organizations will be easier with an NLD government in place. This will require taking the impact on local people, flora and fauna into greater account, but the pendulum has again swung in support of large hydro because of its role in combating climate change, so new dams could still be built.

LOCAL MARKET - CHINESE GAS PRODUCTION AND CONSUMPTION (Bcm)



Source: BP Statistical Review of World Energy

LOCAL MARKET - THAI GAS PRODUCTION AND CONSUMPTION (Bcm)



Source: BP Statistical Review of World Energy

Depending on how relations with Beijing progress, Chinese money could still fund new hydro schemes, just as new dams have been financed by Chinese banks in African democracies, such as Ghana.

However, warmer relations with other Association of Southeast Asian Nations states could see rather less of the country's 39 GW hydro potential tapped because of the impact on the Mekong River. On the other hand, improved relations with the other ASEAN member states should also boost trade and energy consumption, particularly through the introduction of the new ASEAN free trade area and closer power sector integration.

It is probably too soon to judge the impact of the political changes on Myanmar's other neighbors, including Bangladesh and India, but officials in both countries believe that the incoming government offers a fresh start on a number of issues, including delimiting maritime boundaries in the hydrocarbon-rich Bay of Bengal.

They are also hopeful of gaining access to Myanmar's natural gas. Opening up a new gas export route to Bangladesh and India by resurrecting the much delayed tri-nation pipeline project would make political as well as economic sense for the new government, as it would dilute its dependence on a single market, China.

Bangladesh's state minister for power, energy and mineral resources, Nasurl Hamid, told journalists: "We have a fresh plan to purchase natural gas from Chinese firms which have stakes in Myanmar gas fields and are carrying it to China through the pipeline." While existing gas supply contracts will surely be honored, the biggest impact of the political changes could come in influencing the direction of any new gas exports.

The NLD's election victory was a step, albeit a big one, on the road to a new Myanmar. The country's political transformation should be seen as a process rather than an event.

The election was the latest stage on a path to democracy that was agreed in 2011. Suu Kyi herself said: "There's a lot more to be done before our people feel secure enough to celebrate." Yet every step on the road to reform has made it more difficult for the government to turn back.

Floating wind turbines

The evolution of floating wind turbines mirrors almost exactly that of offshore oil exploration and production structures. Norwegian oil company Statoil's decision to build the first floating wind farm represents a carbon risk hedge in an area in which it can deploy its considerable offshore expertise. If costs can be reduced, floating wind farms would hugely expand the exploitable wind resource. **Ross McCracken**

Norwegian state oil company Statoil in November took a final investment decision on a 30 MW floating wind farm offshore Scotland. The project will be a world first and, if successful, would significantly increase the number of potential offshore wind sites. A second 25 MW floating wind farm built by an international consortium offshore northern Portugal should follow close behind in 2018.

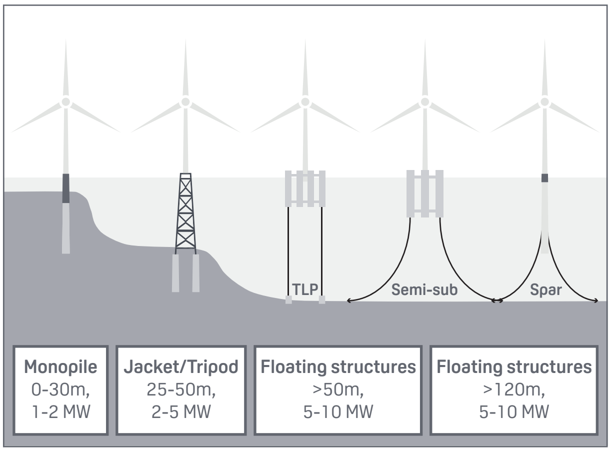
It is no accident that Statoil is leading in this field. The engineering challenges posed by offshore wind, and in particular the transition from grounded to floating wind farms, mirror very closely the evolution of drilling rigs and production platforms as they moved from land to sea.

Statoil's interest in offshore wind power also represents a carbon risk hedge against the prospect of peak oil demand. The company in May established a new business segment called New Energy Solutions, which is designed to complement gradually the company's oil and gas portfolio with renewable and low carbon energy technologies.

A lead in floating wind farms might position an oil company with great experience in offshore technology for reinvention in the face of low-cost oil competition from the Middle East, increasingly stringent emissions regulation and a potentially declining market.

Statoil's new project will be 25 kilometers offshore Peterhead in Scotland and is expected to start generating renewable power from late 2017. The farm will lie in water depths of 95-120 meters and cover 4 square km in area. It will consist of five 6 MW floating turbines in an area with average wind speeds of 10 meters per second.

OFFSHORE WIND FOUNDATIONS



Source: EWEC

Deepwater challenges

The problem for both oil and wind in moving to deeper waters is that remaining attached to the ground becomes progressively more complex and expensive. As a result, for exploration, drilling rigs evolved from land rigs to jack-ups, which have legs and can drill in up to 500 ft of water for the very largest. But beyond that the industry had to move to semi-submersibles, kept in place first by mooring lines and then by dynamic positioning, which uses thrusters to maintain an exact location.

The same was true for drilling platforms. The Gulf of Mexico now hosts some 52 permanent deepwater structures in water depths of more than 1,000 ft, some in more than 8,000 ft. Spars were built that consist of a drilling and production platform atop a huge, almost completely submerged cylinder, weighted at the bottom to provide stability and moored to the seabed.

Both exploration and production have also seen mobile technologies evolve. Exploration has its drillships and production its FPSOs – Floating, Production, Storage and Offloading vessels. These allowed a transition to shuttle tanker delivery rather than pipeline to shore, so that ever more distant fields could be exploited, with the added advantage that the vessel can be redeployed. FPSOs have been widely used around the world, particularly in the development of Brazil's subsalt oil fields. Wind farms are stuck, for the moment, with the limitation of having to run connecting cables to shore, but the potential for a move to deeper water is clear.

Floating wind farm designs are almost identical to offshore production platforms, coming in three main forms; the Tension Leg Platform, which has vertical mooring lines to stabilize a relatively small platform; semi-submersibles, which have larger platforms and are moored with non-tensioned lines; and spars, which feature the long cylinders weighted at the bottom to move the center of gravity of the structure lower than the center of buoyancy, again providing stability. These too have non-tensioned mooring lines.

Spar choice

The technology for Statoil's 30 MW Hywind Scotland Pilot Park is based on the Hywind demonstration project located offshore the Norwegian island of Karmoy, north of Norway's main oil and gas center Stavangar. This was the world's first full-scale floating wind turbine structure and was designed to see how wind and waves would affect turbine performance. A key aim is to reduce hydrodynamic and aerodynamic motion that negatively affects the power output of the turbine.

This project used a spar structure, consisting of a 100 meter cylinder with a diameter of 8.3 meters, filled with ballast water and stones attached to the seabed by three mooring lines. According to Statoil, Hywind has generated 32.5 GWh of electricity since it was completed in 2010. It consists of a single 2.3 MW Siemens turbine in water depth of 200 meters. The project cost to Statoil was NKr400 million ($46.5 million), including research and development, with an additional NKr59 million provided by state enterprise Enova SF.

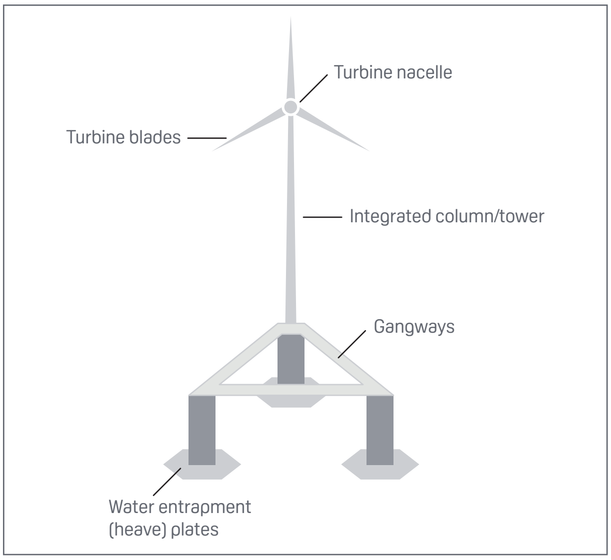
Statoil says that the floating structure can be used with any wind turbine providing that the nacelle and rotor come within the requirements of marine stability. However, the turbine also featured Statoil's proprietary Hywind-specific pitch motion controller, which was integrated with the turbine's control system. This reduced aerodynamic and hydrodynamic motion, optimizing power output.

Although there are mulitple small-scale prototypes around the world, the only other large-scale demonstration floating wind turbine is Windfloat, which was built offshore Portugal in 2011. Developed by Principle Power and Portuguese utility EDP, it features a Vestas 2 MW turbine and started to generate power in 2012. Both Hywind and Windfloat have effectively taken 'off the shelf' turbines and concentrated R&D on the floating structures.

Windfloat has a semi-submersible rather than spar design, using three columns with water entrapment plates at the base of each. It can be fully constructed onshore and then dragged to location by tugs, which reduces deployment and operation costs significantly in comparison with monopole/jacket support structures, not least because no foundation has to be laid at sea. It has four conventional mooring lines that attach to pre-laid drag embedded anchors.

A consortium of EDP Renewables, Mitsubishi Corp., Chiyoda Corp. Engie and Repsol announced in November an

WINDFLOAT WIND TURBINE DESIGN



Source: Principle Power

agreement to build a €125 million 25 MW second phase of the Windfloat project. This would use three to four structures totalling 25 MW and would be located 20 km off the coast of nothern Portugal. The consortium expects to have the project operating in 2018.

Costs

The Hywind wind farm is expected to cost NOK 2 billion ($231 million), which Statoil says represents a 60-70% cost reduction per MW installed compared with the Hywind demonstration project. The price per MW installed is thus in the region of $7.7 million. The company forecasts that further cost reductions of 40-50% can realistically be achieved by 2030.

It is difficult to compare wind farm project costs because they are affected by many factors, such as water depth, distance from shore and turbine size. But, by way of comparison, the proposed (non-floating) 558 MW Beatrice offshore wind farm project, also offshore Scotland, has a stated project cost of £2.128 billion ($3.22 billion), which gives a per MW installed price of $5.8 million.

This project is in shallower water of 35-50 meters and nearer to shore at 18.8 km. It will also use 7 MW rather than 6 MW turbines with a conventional grounded foundation.

The offshore wind industry appears to be having some success in reducing costs. Earlier this year, the 400 MW Horns Rev 3 project in Denmark was awarded at a price of 77 ore per kWh ($0.12/kWh) to Vattenfall Vindkraft, more than 30% cheaper than a tender in 2010 for the 400 MW Anholt wind farm. At a dollar equivalent of about $103/MWh, the award suggested the offshore wind industry had come within a whisker of its goal of $100/MWh by 2020.

However, some developers suggested that Horns Rev 3 might be an outlier in that it is optimally placed in terms of distance from shore, interconnections, and operation and maintenance costs, given its proximity to other Horns Rev projects.

According to Nick Medic, RenewableUK's director of offshore renewables, speaking in June, a more reliable guide is research organization ORE Catapult's offshore wind report of February this year. It showed that the estimated Levelized Cost of Electricity across 20-25 years of UK offshore wind operation fell by 11% between 2011 and 2014. For up-and-running projects in Catapult's report, the LCOE for offshore wind fell from £136/MWh in 2010-2011 to £131/MWh in 2012-2014. For projects at Final Investment Decision stage, reported LCOE dropped to £121/MWh for 2012-2014.

However, floating wind concepts hold some promise that they can cut costs quickly. The European Wind Energy Association says that the production and installation of substructures represents up to 20% of the capex of offshore wind farms. The potential cost savings of floating structures are therefore significant, which, when combined with the potential for larger turbines and stronger winds, suggests at least parity if not lower costs eventually than grounded structures.

Another area of cost reduction is the ability to fully construct the turbine on shore, and in sheltered conditions, which should allow factory line production and assembly. For Hywind, Statoil says the substructures will be transported from the construction site to Norway for assembly. Ballast water will then be used to move the floating structure into a vertical position and the wind turbine will be attached on top by a crane. The complete unit will then be towed to Scotland for final installation with suction piles and mooring. An additional advantage is that a floating turbine can be taken back to port for maintenance rather than relying on expensive jack-up barges operating at sea.

In a July 2013 study, *Deep Water: The next step for offshore wind energy*, the EWEA said that “For a 100 MW wind farm, equipped with 5 MW turbines and installed in water depths of 100 m, the CAPEX for floating designs is similar to the CAPEX of farms using jackets or tripod foundations at 50 m water depths. Similarly the cost of energy produced by the floating designs would be competitive with the fixed-bottom foundations solution.”

What is clear is that the use of larger turbines is reducing costs. This is for a number of reasons, one of which is that a farm can be built with fewer turbines and therefore use less equipment overall and with fewer foundations. Moreover, if a turbine’s blade length doubles, its wind sweep area rises by a factor of four. Taller turbines also benefit from a better wind resource as winds are stronger at 100 meters above ground or sea level than they are at 50 meters, for example.

However, there do appear to be limits on how big turbines can get as upscaling results in unfavorable increases in weight. Increases in the cost of the nacelle and rotor start to offset the gains in operation and maintenance and other component costs. An interesting and as yet untested facet of floating wind is whether it will enable further increases in turbine size, perhaps above and beyond the limitations of grounded foundations.

EWEC envisages 10 MW turbines in the not too distant future. And it is significant that Statoil has opted for 6 MW turbines for the first floating farm. This indicates that it does not see jumping from a 2.3 MW demonstration to turbines close to being the largest on the market as an insurmountable technical challenge.

The company says that it is too early to come to a conclusion on what the optimal size for floating wind turbines might be and that different designs will be capable of carrying different sizes of turbines. However, it is "very confident" that it will be able to increase the scale beyond current state of the art turbines.

Resource expansion

According to the EWEA, grounded offshore wind is limited to water depths of 40 to 50 meters, based on current commercial footings. 66% of the North Sea has a water depth between 50 and 226 meters and could be used for deep offshore wind turbine designs. The 226 meter limit may reflect the cost of mooring line anchors, as well as the increase in cost of being further from shore, as cables need to be laid to carry the electricity back to market.

Floating wind turbines would also allow wind farms in European Mediterranean and Atlantic coasts, where deep water has deterred grounded offshore designs.

EWEC says that, by 2050, the North Sea alone, using 10 MW turbines, could provide enough electricity to meet EU demand more than four times over. This not particularly useful statistic is attributed to the European Commission Low Carbon Roadmap 2050, but it is clear that if floating offshore wind can become economic on a subsidized basis (i.e. the level of subsidy becomes politically tolerable), or even competitive with other forms of electricity generation, then the scope for development is large.

EWEC says that offshore in the US – a country that has yet to build its first offshore wind farm – the wind potential for areas up to 50 nautical miles from land with average wind speeds higher than 7 m/s or more at 90 meters elevation amount to 1,071 GW in water depths of 0-30 meters. There is a further 628 GW in 30-60 meters of water and an estimated 2,451 GW potential in water depths greater than 60 meters.

TECHNOLOGY MONITOR

Companies seek biojet solutions

Companies are exploring drastically different directions in the search for economically viable means of producing renewable jet fuel. Researchers have been incorporating a variety of new and established techniques to turn anything from solid waste to carbon dioxide into a usable jet fuel.

Amyris and Total's project, Lab'line, has undergone commercial flight testing with partner Air France, according to Pascale Demoment of Air Total, speaking at the International Aviation Transportation Association's first Alternative Fuel Symposium in Cancun, Mexico.

Starting in September 2014, an Air France plane made a weekly flight between Toulouse and Paris using 10% farnesane, a renewable jet fuel product developed by converting sugar to hydrocarbon. The plane used standard supply-chain processes and engines and, after 48 flights, researchers found no evidence of equipment or logistics changes, including microbiological contamination.

Another well advanced project is Fulcrum Bioenergy's process of turning municipal solid waste into jet fuel using American Society for Testing and Materials-approved processes of gasification and Fischer-Tropsch synthesis – a collection of chemical reactions that convert a mixture of carbon monoxide and hydrogen into liquid hydrocarbons.

According to Bruno Miller, Fulcrum's managing director of fuels, the process can produce 10 million gallons of renewable jet fuel for under $1/gal using 200,000 tons/year of waste.

Fulcrum's first plant is being built in Nevada, which aims to meet the company's goal of producing 300 million gallons of jet fuel, Miller said.

Despite its low-cost model, Miller said the company's success and growth has been limited by its access to capital. Cathay Pacific was the first airline to make a capital investment, agreeing to buy 2% of their annual jet fuel supply from Fulcrum over 10 years. United Airlines has made a similar off-take deal for 900 million gallons over 10 years.

Gevo, a Colorado-based biofuels company, is developing an alcohol-to-jet process, designed to convert sugars into isobutanol and then into renewable hydrocarbons for processing. The finished product would be a 50:50 blend with conventional jet fuel. Glenn Johnston, Gevo's executive vice president, said they expect to receive final approval for the process in early 2016. Any product receiving final ASTM approval for jet fuel can be transported and blended safely with the rest of the jet fuel pool.

While many biojet options currently in development require blending, some companies are hoping to produce drop-in alternative jet fuel capable of operating without a blend of petroleum jet. Chuck Red, the vice president of Applied Research Associates, said its relatively small operation in Panama City, Florida – capable of producing about 100 b/d of JP-5 jet fuel – is doing that by taking fats, crop seed oils and algae to create a crude oil free of sulfur.

The crude then goes through hydrotreating and fractionation to produce a finished jet fuel that Red says can be incorporated into existing engines without blending. Red said the company's proposal is next in the queue for ASTM certification, with a decision expected next summer. However, ASTM has downgraded ARA's proposal and is instead reviewing its renewable jet fuel as a 50:50 blend.

Red was more optimistic for achieving US Military Standard approval for 100% drop-in JP-5 jet fuel by end-2016, noting one military official had told him "a 50% blend is only 50% of the solution."

Looking to completely reverse the combustion process, Joule Unlimited's plan for renewable fuels comes from leveraging captured CO_2 and solar energy to reform fuel for processing. Michael Conner, a senior scientist with Joule, said that their process industrializes photosynthesis using genetically modified molecules for catalysts that are capable of producing fuel. Connor noted that while other biofuels require some sort of crop to be grown, Joule's process does not compete for arable land.

Joule anticipates building its first commercial plant in 2018-2019 and is targeting desert climates to optimize productivity. But others at the event questioned the reliability of solar and were concerned about consistent production during bad weather. The company is still in the early stages of development, Conner said, adding Joule has spent more resources developing their renewable diesel and ethanol, but is hoping to use its diesel process to make jet fuel as well.

Solar thermal energy storage

Engineers at Oregon State University have identified a new approach for the storage of concentrated solar thermal energy using thermochemical storage. Solar thermal electricity uses acres of mirrors to reflect sunlight on to a solar receiver, which heats a fluid, typically molten salt. This heat is then used to produce steam and drive a turbine to generate electricity.

This new innovation uses chemical transformation in repeated cycles to hold heat, allowing the dispatch of electricity at any time of day or night. Thermochemical storage resembles a battery, in which chemical bonds are used to store and release energy, but in this case, the transfer is based on heat, not electricity.

The system hinges on the reversible decomposition of strontium carbonate into strontium oxide and carbon dioxide, which consumes thermal energy. During discharge, the recombination of strontium oxide and carbon dioxide releases the stored heat. These materials are nonflammable, readily available and environmentally safe, the researchers say.

In comparison to existing approaches, the new system could also allow a 10-fold increase in energy density, which would make the system much smaller and cheaper to build. The proposed system would work at such high temperatures that it could first be used to directly heat air, which would drive a turbine to generate electricity. The residual heat could then be used to produce steam to drive another turbine.

"With the compounds we're studying, there's significant potential to lower costs and increase efficiency," said Nick AuYeung, one of the authors of the study. "The molten salts now being used to store solar thermal energy can only work at about 600°C, and also require large containers and corrosive materials. The compound we're studying can be used at up to 1,200°C, and might be twice as efficient as existing systems."

However, the researchers have yet to build a prototype for testing in a national laboratory. One key problem is that the energy storage capacity of the process declined after 45 heating and cooling cycles, due to changes in the underlying materials.

Researchers in Australia are also looking at a similar technology that uses silicon derived from sand. According to development company Latent Heat Energy, electrical energy can be stored and released by heating and melting containers full of silicon, which has a high latent heat capacity.

The company says that their Thermal Energy Storage System is scalable up to several hundred MWh and is designed for integration with variable renewable electricity generation. LHE has secured a A$400 million ($282.4 million) grant to take the technology from prototype to commercial development.

Bioplastics capacity outstripping conventional industry growth

Worldwide production of bio-based polymers is expected to triple from 5.7 million tons in 2014 to nearly 17 million tons in 2020, according to a report released in November by the Nova Institute. Turnover in the sector in 2014 is estimated at €11 million ($11.75 million), a 10% increase from 2013.

According to the report, bio-based polymer production capacity accounted for a 2% share of overall structural polymer production of about 256 million tons. Bio-based polymer production is expected to grow faster than the wider comventional sector and account for about 4% of a total 400 million mt market by 2020.

Drop-in bio-based polymers are expected to grow fastest. These are chemically identical to their petrochemical counterparts, but at least partially derived from biomass. The report says this group is led by partly bio-based polyethylene terephthalate, largely due to the Plant PET Technology Collaborative initiative launched by Coca-Cola. Polyhydroxyalkanoates, which are new polymers, are expected to see the second strongest growth.

The report also predicts a strong shift in market shares from Europe and the US to Asia, which by 2020 is expected to account for 80.6% of the bioplastics market in terms of production capacity, up from 58.1% in 2014.

Bioplastics companies are creating new polymers as well as replicating fossil-fuel based ones, with differing degrees of biomass input. Epoxies, for example, have 30% bio-based content, while polyethylene is a 100% bio-based drop-in polymer made from bio-based ethylene, which in turn is derived from sugar cane. The report notes that bioplastics production has suffered from low oil prices and the shale gas boom, which has reduced the price of fossil fuel feedstocks for the petrochemical industry.

TECHNOLOGY AND DEPLOYMENT IN BRIEF...

New PV efficiency record PV module manufacturer Trina Solar Limited announced in November that the State Key Laboratory of PV Science and Technology of China has set a new world record of 21.25% for a high-efficiency p-type multi-crystalline silicon (mc-Si) solar cell. The cell was fabricated on a high-quality mc-Si substrate.

This result has been independently confirmed by the Fraunhofer ISE CalLab in Germany. The previous efficiency record was 20.76%, which was set by Trina Solar one year ago. The company says only low cost industrial processes were used in making the cell and that these can easily be integrated into large-volume production.

Quest CCS starts commercial operation Anglo-Dutch oil major Shell started commercial operations in November at its Quest Carbon Capture and Storage project in Alberta, Canada. Quest is designed to capture and store more than one million tons of CO2. Quest will capture one-third of the emissions from Shell's Scotford Upgrader, which turns oil sands bitumen into synthetic crude that can be refined into fuel and other products.

The CO2 is then transported through a 65-km pipeline and injected more than two kms underground below multiple layers of impermeable rock formations. Quest is now operating at commercial scale after successful testing earlier this year, during which it captured and stored more than 200,000 tonnes of CO2. Quest was made possible by the support of the governments of Alberta and Canada, which provided C$865 million in funding.

Regenerative braking advance Hyundai Mobis has become the first in Korea and the second in the world to develop an electronic integrated regenerative brake system for hybrid and electric vehicles. iMEB integrates the pressure supply unit and the pressure control unit of the regenerative brake system into a single electronically driven unit. This allows more than 30% cost and weight reduction. The system uses kinetic energy from the car's deceleration to charge a battery. According

TECHNOLOGY AND DEPLOYMENT IN BRIEF...

to the company, iMEB can reduce the energy dissipation rate by close to 70% compared with existing brake systems.

Vanadium flow battery Sparton Resources has started commissioning of its 8 MWh vanadium flow battery at the Zhangbei Project in cooperation with battery owner, the State Grid North China Company Ltd. Testing started November 21 and will take place over several weeks. The Zhangbei Project is located 60 kilometers north of Beijing in Hebei Province, China. According to Sparton, it is the world's biggest renewable energy utilization platform, integrating wind power, solar power, energy storage and smart grid transmission technologies. Power generated by this project will be integrated into north China's energy grid.

The project currently includes 500 MW of wind power and 100 MW of solar power, with 110 MW of energy storage capacity, and covers a total land area of 200 square km. There are plans to expand both electricity generation from wind and solar sources, and add further energy storage capacity. With a total investment of 12 billion RMB ($1.8 billion), upon completion, it will be China's largest grid integrated solar power generation station and its largest land-based wind farm in unit capacity, as well as the world's largest chemical energy storage station.

Bacterial ethanol fermentation scales up French Biotech company Deinove, which uses the Deinococcus bacteria to produce ethanol from biomass, has announced that it has produced ethanol with 5.8% weight by volume in the fermentation broth, which it describes as "an exceptional performance level" in a 300-liter fermenter. The raw material used was a mixture of glucose and xylose, the main components obtained by the hydrolysis of non-food biomass.

The company says fermentation of these sugars by an optimized bacteria strain has produced ethanol at a rate consistent with results obtained by Deinove in its laboratories in 20-liter fermenters. "This is a great step towards industrialization of the process and this result confirms that the Deinococcus platform is suitable for commercialization," said Deinove CEO Emmanuel Petiot. Deinove says it is confident it will have an economically competitive process by 2018.

Biodiesel facility coming on-line The world's first biofuel production facility to operate entirely on renewable heat and power is expected on-line December 4, according to bioenergy company Biodico. The Biodico Westside Facility, which is located in the San Joaquin Valley in Califonia, is expected to produce up to 20 million gallons of biodiesel per year. It has the capacity to use different feedstocks and features complete process automation.

Lower biofuel plant costs Alliance BioEnergy Plus, Inc. claims that it has significantly reduced the capital cost of second generation biofuel production with its CTS biofuel process. It says its CTS Cellulose Ethanol plant will process 1,000 mt a day of virtually any cellulose biomass and produce upwards of 34 million gallons a year of high-grade ethanol with 86% less emissions than gasoline. It estimates the cost of the plant at $1.97 per nameplate gallon to build, which it says is much cheaper than its competitors. The CTS process is described as a mechanical/chemical technology, involving the addition of a patented catalyst.

New use for old coal plant A joint venture between US companies Duke Energy, LG Chem and Greensmith have announced the completion of a 2 MW lithium-ion battery energy storage system at the site of a retired coal plant, originally built in 1952. The fast-response system is now actively regulating electric grid frequency for regional transmission organization PJM and was installed in five months. The siting of the project at an old coal plant has allowed the companies to take advantage of the existing grid infrastructure.

More powerful BOP BOP Technologies says it has developed a revolutionary blowout preventer that delivers five-million pounds of shearing force, enough for the oil and gas industry to manage future, more challenging drilling projects safely. This is more than two-and-a-half times the shearing force of any BOP available today. The design also means the size of BOPs can be reduced by as much as 30%, allowing oil and gas companies to drill safely in deeper waters and under higher pressure without having to use preventers that are prohibitively large. The blowout preventer is the last line of defense to keep an accident or unexpected event from turning into a disaster when drilling oil and gas wells.

FORTHCOMING CONFERENCES AND EVENTS

South Asia Power 2015
December 1-3
Colombo, Sri Lanka
www.neoventurecorp.com/events/southasiahydro

7th Annual Geopower Global Congress
December 1-3
Istanbul, Turkey
www.geopowerglobal.com

World LNG Summit
December 1-4
Rome, Italy
http://world.cwclng.com/

Powering Africa: Tanzania
December 3-4
Dar es Salaam, Tanzania
www.energynet.co.uk/event/powering-africa-tanzania

Electrix
December 6-8
Cairo, Egypt
www.electrixegypt.com

International Petroleum Technology Conference
December 6-9
Doha, Qatar
http://atnd.it/28386-0

Middle Eastern Crude Summit
December 7-9
Dubai, UAE
www.platts.com

North Africa Oil & Gas Summit
December 7-9
Algiers, Algeria
www.theenergyexchange.co.uk

Energy Storage India Conference & Expo
December 8-9
New Delhi, India
http://www.esiexpo.in/index

Global Energy Outlook Forum
December 9
New York, USA
www.platts.com

CIS & CEE Downstream Project Management
December 9-10
Milan, Italy
http://globuc.com/events/downstream_technology_2014

South Eastern European Power Summit 2015
December 9-10
Bucharest, Romania
www.wplgroup.com/aci/event/south-eastern-european-power-summit-2015/

ENTECH '15 International Energy Technologies Conference
December 21-23
Istanbul, Turkey
http://www.entechconference.com/

Gas Storage Outlook
January 11-12, 2016
Houston, USA
www.platts.com

3rd Myanmar Electric Power Generation
January 13-15, 2016
Yangon, Myanmar
www.neoventurecorp.com/events/mepc/

European Oil Storage Conference
January 18-19, 2016
Amsterdam, Netherlands
www.platts.com

Utility Supply Chain Management Conference
January 18-20, 2016
Coronado, USA
www.platts.com

World Future Energy Summit 2016
January 18-21, 2016
Abu Dhabi, UAE
www.worldfutureenergysummit.com/

Central Eastern & European Power Conference
January 21-22, 2016
Warsaw, Poland
www.platts.com

World Gas Congress Africa 2016
January 21-23, 2016
Maputo, Mozambique
http://www.szwgroup.com/world-gas-congress-africa-2016/

Middle Distillates Conference
January 26-27, 2016
Antwerp, Belgium
www.platts.com

5th International Conference on Clean abd Green Energy – ICCGE
February 1-3, 2016
Rome, Italy
http://www.iccge.org/

Photovoltaica 2016
February 2-4, 2016
Casablanca, Morocco
www.photovoltaica.ma/index.php/en/

6th World PetroCoal Congress & Expo-2016
February 15-17, 2016
New Delhi, India
http://worldpetrocoal.com/

Africa Energy Indaba
February 16-17, 2016
Johannesburg, South Africa
http://www.africaenergyindaba.com/

International Conference on Electrical Energy and Networks
February 18-19, 2016
Nice, France
http://www.iceen.org/

Middle East Electricity
March 1-3, 2016
Dubai, UAE
www.middleeastelectricity.com

World Bio Markets 2016
March 14-17, 2016
Amsterdam, Netherlands
www.worldbiomarkets.com

Power & Energy Kenya 2016
May 12-14, 2016
Nairobi, Kenya
www.expogr.com/kenyaenergy

11th International Energy Conference 2016
May 30-31, 2016
Tehran, Iran
http://www.irannec.com

IAEE International Conference
June 19-22
Bergen, Norway
www.iaee2016nhh.no

POWER-GEN Europe and Renewables Energy World Europe 2016
June 21-23
Milan, Italy
www.powergeneurope.com

Biofuels International 2016
September 21-22
Ghent, Belgium
www.biofuels-news.com/conference

World Energy Congress
October 9-13, 2016
Istanbul, Turkey
http://www.wec2016istanbul.org.tr

LETTER FROM ISTANBUL: NOVEMBER 2015

AKP back in control

The Turkish general election on November 1 saw the Justice and Development Party (AKP) returned to power with a comfortable majority, less than six months after an earlier poll saw it lose its majority in the country's 550-seat parliament. However, with 57.45% of parliamentary seats, the AKP fell just short of the 3/5ths majority required to call a referendum on constitutional change on its own.

While regaining its majority may have returned the AKP to power, it now has some tough choices to make on major issues related to natural gas imports and transit. Not least is what to do about the rumbling spat with Moscow over the price Turkey's state gas importer Botas pays for Russian gas imports and the future of the TurkStream gas line that Russia wants to build across the Black Sea. Russia delivers up to 30 Bcm/year of Turkey's total gas import portfolio of 52.05 Bcm/year.

According to Turkey's interim energy minister Ali Riza Alaboyun, Botas has launched arbitration proceedings against Russia's state gas company Gazprom for failing to implement a 10.25% discount agreed in talks earlier this year. A report carried by Turkey's state news agency *Anatolia* two days after the election claimed that the matter would be settled between Gazprom and Botas without the need for court proceedings, but this has yet to be confirmed officially. The report may prove premature as the new Turkish cabinet was not due to be announced until November 28, as *Energy Economist* went to press.

Disagreements between Ankara and Moscow are not restricted to the gas discount. They also encompass the planned TurkStream line, the Akkuyu nuclear power plant that Russia's Rosatom is developing in Turkey, and Russia's decision to launch air strikes against Syrian rebels in support of the Assad regime.

The root problem remains the TurkStream pipeline, announced late last year by Russian President Vladimir Putin to replace the now abandoned 63 Bcm/year South Stream pipeline project. Turkish officials confirmed earlier this year that they had agreed in principle to the development of one of the four parallel 15.75 Bcm lines that will make up the planned route. They also said that the agreed discount on Russia gas imports was not dependent on Turkstream.

However, with formal approval of the pipeline requiring the Turkish parliament to ratify an intergovernmental agreement, and with Turkey's opposition parties opposed to further energy dependence on Moscow, the project has been on ice since the June election. Ratification should now be a formality, but it is also likely to be tied to an agreement on the disputed discount and on the construction of the Akkuyu nuclear power plant, which will complicate negotiations.

Moscow upped the ante in early October when it revealed that TurkStream's planned capacity was to be cut from the original 63 Bcm/year to 32 Bcm/year. It has also announced the possible expansion of the Nord Stream pipeline that runs under the Baltic Sea to Germany, implying that more Russian gas would use the northern route if no agreement could be reached with Turkey.

Both Turkey and Russia have other agendas. Turkey is a partner in developing the 31 Bcm/year Trans-Anatolian Pipeline (TANAP) from Azerbaijan. But with Azerbaijan currently only able to commit 16 Bcm/year to TANAP, Turkey has a tough job in finding additional gas for the pipeline.

With new sources of gas from the Azeri and Turkmen sectors of the Caspian Sea unlikely to be available for as much as a decade, gas from the Kurdistan region of northern Iraq is being touted as a possible candidate to fill the empty capacity. Turkey and the Kurdistan Regional Government signed a gas purchase agreement in late 2013, with Anglo-Turkish Genel Energy signaling that it could supply volumes from its Bina Bawi and Miran prospects.

Botas has already said it plans to begin construction of a 20 Bcm/year capacity transit line linking the Turkey-Iraq border to its existing transmission grid. And Genel recently launched its own "midstream gas" operation in Turkey, suggesting gas could be arriving within the next 2-3 years either for Turkish consumption, or transit or both.

However, that prospect presents Turkey with another difficult political choice: how to deal with its own Kurdish issues. The AKP's election victory came largely on the back of its tough military stance against the Kurdistan Workers Party (PKK), which in July ended its two-year ceasefire and began launching attacks into Turkey from its bases within the KRG-controlled region of Iraq.

Having secured another four years of single party rule, the AKP now has the choice of trying to restart the failed peace process with the PKK – which could help secure Kurdish gas supplies – or continue with its military campaign to remove the PKK from northern Iraq. The latter may offer domestic political advantage, but would risk not just stalling the arrival of Kurdish gas, but also further destabilizing the Kurdistan region, which is already locked in a vicious war with the forces of Islamic State.

The KRG government is heavily dependent on Turkey with regards to oil exports, which come by pipeline from Kirkuk in Iraq via the KRG controlled area to Turkey's Mediterranean port of Ceyhan and by road to other Turkish ports. According to the KRG, it exported on average 595,000 b/d of crude from Ceyhan in October, of which 439,000 b/d came from fields in the Kurdish region of Iraq and 156,000 b/d from fields operated by Iraq's North Oil Company.

— David O'Byrne

LETTER FROM MOSCOW: NOVEMBER 2015

Diplomatic push

Pictures of an impromptu face-to-face meeting between Russian President Vladimir Putin and US President Barak Obama in the lobby of the G20 summit in Antalya, Turkey, in November, gave at least symbolic form to suggestions that Moscow is being welcomed back in from the cold.

It was a certainly a stark contrast to the frosty reception he received at the G20 in Brisbane, Australia, just one year ago. The new mood music reflects the shift in political agendas towards the threat posed by Islamic State and instability in the Middle East, which was heavily reinforced by the terrorist atrocities that took place in Paris just a few days before the G20 leaders met.

However, the G20 was just one platform in what has been major a diplomatic push by Moscow, and the reason for that push is money. With the oil price in the doldrums, and sanctions affecting Russian companies' ability to borrow abroad, cash is scarce in Moscow. Moreover, despite the announcement of new levels of cooperation and the signing of multiple memoranda, Asian countries that might prove alternatives to Western finance have proven relatively cautious when push comes to shove.

As a result, two days after the G20 summit, Russian Prime Minister Dmitry Medvedev renewed calls for Asian countries to invest in Russia. Russia is offering favorable terms for foreign investment in its eastern regions, where a significant part of its new oil and gas reserves are located, Medvedev told the Asia Pacific Economic Cooperation summit in Manila, Philippines.

"The opportunities for expansion of business cooperation in the region are huge," he said. "Russia can secure stable, long-term deliveries of energy resources to the Asia-Pacific region .... at competitive prices. Such an opportunity must be used," he said.

Earlier in November, Russia also took part in the 6th Asian Ministerial Energy Roundtable in Doha, Qatar, attending the gathering of the region's top energy ministers and policy makers for the first time. The Russian delegation met with its main partner in the region China, as well as India, Qatar, Bahrain, the UAE and others to talk about participating in local projects.

Russia sees Asia as both the key to market diversification and as a source of capital to help develop the new upstream projects that will supply the region. It should be a match made in heaven. Moscow hopes that by 2020, it will be sending natural gas to China by pipeline and up to 30% of its oil exports to Asia, compared with around 20% now.

It is already making progress. For two months so far this year, Russia displaced Saudi Arabia as China's top crude supplier. In the first nine months of the year, Russian supplies of crude oil to China rose by 30% to an average of 813,692 b/d. Oil supplies to Japan have risen 6% to 253,469 b/d and to South Korea by 35% to 135,187 b/d over the same period. Pipeline gas deliveries to China are scheduled to start in 2019, with the two countries having started construction of the 38 Bcm/year Power of Siberia pipeline from East Siberia.

A Russian delegation also visited China in mid-November. Following the talks, deputy energy minister Anatoly Yanovsky said a deal might be struck for China's state-run Silk Road Fund to take a 9.9% stake in the Novatek-led Yamal LNG project by the end of this year. SRF is also expected to provide a loan.

In addition, progress appears to have been made on slow-moving talks to agree a $12 billion loan from Chinese banks for the project. Yamal LNG is the most advanced of Russia's LNG projects, and would be only the country's second LNG plant in operation. The total project cost is $27 billion and the inability to secure financing risks serious delay.

In addition, state-run oil company Rosneft is expected to ink binding agreements with China's Sinopec on the joint development of the major Russkoye and Yurubcheno-Tokhomskoye fields in East Siberia, following the signing of a memorandum in September. The deal, if finalized, would see Sinopec take a stake of up to 49% in the projects.

These deals are seen as critical for the long-term development of Russia's hydrocarbon resources. Despite sanctions and low oil prices, Russia's oil sector is operating well, drawing support from the drastic devaluation of the ruble and a tax system that sees tax payments fall as the oil price drops. It is sustaining that performance beyond 2016 that is the problem.

In 2015, overall investment in Russia's oil sector is estimated at over Rb1.188 billion ($18 billion), a 20% increase year-on-year in ruble terms. This has kept the oil flowing. Crude output has hit record post-Soviet highs repeatedly over the year and is expected to average about 10.7 million b/d for 2015 as a whole, a rise of about 1% from 2014.

However, the outlook for next year is very different. Investment in the sector is expected to drop by 15% to below Rb1 trillion. This is likely to result in a fall in production of 120,000-200,000 b/d in 2017. And beyond that, the decline may accelerate, as Russian companies have already delayed some future projects aimed at mitigating the natural decline of mature fields after 2020 to focus instead on short-term output maximization to maintain cash flow.

— Nadia Rodova

LETTER FROM WASHINGTON: NOVEMBER 2015

Coal incentives

It's no secret that this is a tough time for the US coal industry. This year alone 13 GW of coal-fired plant is slated for retirement. The industry is wracking its brains trying to figure out how to survive in a carbon-conscious world, and, interestingly, it is looking to the renewable energy industry for inspiration.

The National Coal Council recently recommended that the federal government grant the coal industry solar and wind energy-like incentives for Carbon Capture and Sequestration. It's easy to see why. Solar energy supplied 40% of new US generating capacity in first-half 2015, more than any other energy technology, according to the Solar Energy Industries Association. This comes on top of a 20-fold increase in solar since 2008.

Solar success in the US is often traced back to the mid-2000s when solar developer SunEdison and others came up with sophisticated financing packages that leveraged a 30% federal tax credit. The industry really took off when Congress agreed to extend the tax credit for eight years from 2008 to 2016, giving investors certainty and the industry time to further refine its financing packages.

Now the coal industry says it's time to give them the same kind of boost. The white paper argues that renewables are getting all of the financial goodies in the US, while coal is left with the scraps. It says renewables received 12 times more subsidies than coal in 2013 – $13.227 billion in comparison with just $1.085 billion for coal. Financial support for renewables rose from 14.9% in 2007 to 72% in 2013, while coal's share dropped from 12.7% to 6%, the council said.

The disparity not only creates an unfair playing field, but also causes actual market harm to coal, according to the white paper. "The subsidy for electricity from renewables is so large that it has enabled renewable energy producers to sell into energy markets at a negative price, which in deregulated markets can have the effect of reducing market prices for non-subsidized fuels – i.e., fossil and nuclear," the council argues.

Many see CCS as a possible savior for the US coal industry. But despite years of effort by government and private companies, the technology remains costly. The council reasons that CCS is a clean energy source – one that will reduce CO_2 emissions – so therefore should be eligible for clean energy-type support.

The paper calls for granting CCS a menu of financial incentives, including a production tax credit equivalent to the $23/MWh now available for renewables. In addition to tax credits, the white paper recommends guaranteed purchase of CCS electricity, akin to the purchase requirements under the Public Utilities Regulatory Policy Act of 1978 that spurred early renewable projects.

The coal council is also pushing to create market 'set asides' for CCS, much like state renewable portfolio standards that require that a certain percentage of power comes from renewables. However, it's not clear that this approach would help, as five states – Utah, Michigan, Ohio, West Virginia, and Massachusetts – already incorporate CCS into their portfolio standards, but none have CCS projects.

Clean Renewable Energy Bonds and Master Limited Partnerships also made the coal council's wish list. Now used for oil and gas projects, MLPs receive favorable tax treatment. However, they too might prove a tough call as the renewables industry has been fighting for years for Congress to allow them to participate in the partnerships, but to no avail.

The fact is that making the financials work for CCS has not been easy. The report, produced at the request of Energy Secretary Ernest Moniz in advance of the UN Paris Climate meeting in December, comes at the end of what's been a difficult year for the technology.

Early in the year, the federal government withdrew its financial support for FutureGen, a major CCS pilot project that's struggled since 2003. The project faltered even after receiving a $1 billion boost under the American Recovery and Reinvestment Act of 2009. The federal government also canceled or reduced funding for two of three other CCS demonstration projects, the Texas Clean Energy Project and Hydrogen Energy California.

So CCS is no foreigner to government support. But maybe the support has not been the right kind. Like wind and solar in the 1990s, CCS is an immature technology that carries high risk and capital costs, the paper argues. Ultimately, the council says CCS needs up-front incentives that reduce risk.

As much as anything else, coal faces a public relations problem, which the white paper acknowledges. It calls for the US Department of Energy to "vigorously explain reality" to the American public.

That reality, according to the coal council, is that cities are growing and energy is needed. So the federal government "must be a tireless advocate in all venues for recognition that fossil fuels will be used in coming decades to a greater extent than today to fuel a more populous, developed, urban world," the coal council says. "Those who deny these facts" do harm to the US quest to decarbonize.

That may or may not be true. But winning over Congress to the idea of incentives for CCS won't be easy. Still, it's easy to see why the coal council wants to give it a try. Solar and wind saw tremendous growth after slow beginnings once they found the right financial models. Perhaps CCS would see the same.

— *Elisa Wood*

LETTER FROM BRUSSELS: NOVEMBER 2015

Network code progress

Progress on integrating the EU's 28 national energy markets can seem painfully slow at times, but changes at grid level are finally happening. The EU's third energy package, adopted in 2009 and applied since 2011, included a new process for developing and making binding common EU rules for electricity and gas transmission system operators and users, known as network codes.

The codes aim to make it easier to send electricity and gas across different grid systems, so that they flow in response to market signals and not national borders. Gas is further ahead than electricity, with the balancing network code formally applying since October 1 and the capacity allocation mechanisms code applying since November 1.

The gas balancing code is intended to introduce harmonized, market-based within-day balancing regimes across the EU, and to define clearly the balancing responsibilities of grid operators and users. Full gas balancing harmonization is still some years off. Ten EU countries implemented the code by October 1, 2015, while another five plan to implement the code by October 2016, including Italy. A further ten countries plan to apply interim measures allowing them until April 2019 to implement some of the provisions, including the trading platform, daily imbalance charge and tolerances.

The gas capacity allocation mechanisms code includes requirements to auction cross-border capacity on joint booking platforms, to sell capacity on either side of interconnection points as one bundled product, and harmonizes the gas day across the EU at 0500 to 0500 GMT – which means a change for the UK, which used 0600 to 0600 GMT before.

There are three joint booking platforms so far, of which the biggest and most established is Prisma. As of August, there were 32 TSOs from Austria, Belgium, Denmark, France, Germany, Ireland, Italy, the Netherlands, Portugal, Slovenia, Spain and the UK using Prisma, while Poland was using GSA and Hungary and Romania's national TSOs were using RBP. GSA is run by Polish gas transmission system operator Gaz-System, while RBP is run by Hungarian gas TSO FGSZ.

A code on gas interoperability and data exchange is to apply from May 1, 2016 and sets standards for interconnection agreements, among other things, which could help Ukraine for example update its agreements with EU neighbors to allow for more virtual reverse flows.

However, a code on harmonizing gas tariffs is proving the most controversial, with EU energy regulatory agency ACER failing to agree a formal recommendation on it to send to the European Commission for final approvals – the first time this has happened. The commission will have to work on the latest text submitted to ACER by formal EU gas grid operators' body Entsog, to prepare a final version for approval by an EU committee of national government experts.

Electricity is moving more slowly partly because the codes are longer and more complicated. Only one of the ten codes being developed has completed the process so far. The capacity allocation and congestion management code has applied since August this year, but many of its provisions are being phased in over time, including defining capacity calculation regions and nominating at least one electricity market operator in every bidding zone to run day ahead and/or intraday market coupling .

Three electricity grid codes setting common connection rules for generators, users and high voltage transmission system lines have been approved by an EU committee of national government experts, as well as one on forward capacity allocation. This last code sets out the rules for allocating long-term transmission rights, including the type and quantity of the rights, how they are allocated and how to compensate buyers if their rights are curtailed.

All four codes now have to be scrutinized by the European Parliament and EU Council, representing national governments, and then published in the EU Official Journal in order to become binding, a process which takes several months.

The EU committee is due to vote on a further three electricity codes – on operational planning and scheduling, operational security and load frequency and reserves – in December. The commission plans to present the two remaining codes, on balancing and on emergency and restoration of supplies, for approval by the committee next year.

The commission is holding off on finalizing these last two codes because of its plans to propose new EU electricity legislation next year, including on market design and supply security, which will cover some of the same issues.

Shorter balancing periods, for example, could help integrate the EU's growing share of intermittent renewables more efficiently into markets. As part of work on the balancing code, formal EU power grid operators' body Entso-e is inviting feedback on the potential costs and benefits of harmonizing and shortening the imbalance settlement periods across the EU, Liechtenstein, Norway and Switzerland. It is looking at the status quo, 30, 15 and five-minute periods.

A commission public consultation on electricity market design this summer found that most responders wanted scarcity pricing – prices that better reflect actual supply and demand – with more hedging products to minimize the risks of volatility. It also said a significant number wanted legal measures, on top of the network codes, to speed up cross-border balancing markets and provide clear legal principles for taking part in such markets.

— Siobhan Hall

Expected rise in Iranian crude export volumes non-negotiable

Iranian Oil Minister Bijan Zanganeh said in November that the Iranian government would not change its plan to boost crude production and exports when nuclear sanctions on Tehran are removed, even if oil prices fall to $30/barrel. Nor will Iran negotiate with OPEC on its plans to increase supply, Zanganeh said, insisting on the country's right to regain its place in world markets.

Oil prices were trading below $45/b in November, having plunged from as high as $115/b in mid-June last year under the weight of climbing supply and brimming stockpiles.

Zanganeh, speaking at a press conference in Tehran, reiterated that Iran would increase its crude exports by 500,000 b/d immediately upon the removal of the sanctions that have crippled the country's oil sector and economy. However, he said that the market had already factored Iran's additional barrels into the current price.

"The market has already considered this much addition in the future contracts, one month sooner or later, in January, February, so the price impact can be seen now. "We shouldn't be worried about the oil price," he said. "Those should be who sold more oil and increased their production," he added, without naming any countries.

Iran was exporting around 2.2-2.3 million b/d of crude before tightened sanctions in mid-2012, including an EU oil import embargo, restricted exports to around 1 million b/d and the number of buying countries to six – China, India, Japan, South Korea, Turkey and Taiwan.

Zanganeh, who has previously flagged a doubling of crude exports within six months of the lifting of sanctions, said Iran would target Asia for the bulk of its exports, but would also work to regain its European markets. "We will try to go back to the 40% [of exports] to Europe, 60% to Asia. And if we can sell more to Asia, we will, because price is usually somewhat higher in Asia, a few cents and we are interested in Asian markets," he said.

Sanctions are expected to be lifted early next year, once the International Atomic Energy Agency has verified Iran's compliance with the nuclear deal reached in July. The IAEA expects to issue a final report by December 15.

OPEC, the oil producer group of which Iran is a founder member, will review its policy December 4 in Vienna. But Zanganeh made clear that Iran would not seek OPEC's approval for its plans to increase output. "We won't negotiate about it," he said.

A year ago, despite fast-falling oil prices, Saudi Arabia persuaded OPEC not to reduce production, but to defend its market share by maintaining official output at 30 million b/d. OPEC output is currently running above 31 million b/d and Saudi Arabia itself has been pumping at record levels above 10 million b/d since March this year.

Saudi Arabia, OPEC's most influential producer, has given no indication that it is ready to relax its market-share strategy at OPEC's December 4 meeting in Vienna. According to a Platts survey, OPEC production slipped in October by 120,000 b/d to 31.08 million b/d.

Commenting on the likelihood that OPEC would continue with its current strategy, Zanganeh said: "It is not expedient, but every decision needs consensus. I think supply is high in the market and OPEC doesn't even comply with its own ceiling now. But we don't have any power to tell others to do something. Everyone should agree to do something based on consensus," he said.

Forecasters expect non-OPEC output to contract as a consequence of low prices. The International Energy Agency sees non-OPEC supply falling by 600,000 b/d next year and demand for OPEC oil increasing by 1.44 million b/d. However, the IEA, in its latest monthly report, also noted forecasts of a mild winter in the US and Europe, and said that if these expectations turned out to be the case, "bulging stock levels will add further pressure and oil market bears may choose not to hibernate."

COUNTRY-BY-COUNTRY BREAKDOWN OF OPEC PRODUCTION (million b/d)

Country	October	September	August	July	June	May	April	March
Algeria	1.11	1.11	1.11	1.11	1.12	1.12	1.10	1.10
Angola	1.78	1.80	1.78	1.80	1.75	1.75	1.68	1.75
Ecuador	0.54	0.54	0.54	0.54	0.54	0.55	0.55	0.55
Iran	2.88	2.88	2.87	2.87	2.85	2.85	2.86	2.85
Iraq	3.65	3.72	3.72	3.75	3.75	3.65	3.60	3.53
Kuwait	2.75	2.75	2.75	2.75	2.75	2.77	2.80	2.78
Libya	0.42	0.37	0.36	0.39	0.41	0.43	0.52	0.48
Nigeria	1.95	1.87	1.85	1.85	1.90	1.88	1.90	1.86
Qatar	0.66	0.66	0.66	0.67	0.67	0.67	0.68	0.68
Saudi Arabia	10.10	10.26	10.40	10.45	10.35	10.25	10.10	10.00
UAE	2.90	2.90	2.88	2.88	2.85	2.85	2.82	2.82
Venezuela	2.34	2.34	2.34	2.34	2.34	2.34	2.32	2.32
Total	31.08	31.20	31.26	31.40	31.28	31.11	30.93	30.72

Source: Platts

No oil market balance until 2017/18

The global oil market is unlikely to find a balance between supply and demand until 2017/18 at the earliest, according to Russia's deputy energy minister Alexei Teksler. This balance will eventually result from widespread cuts in exploration and production investment, which in turn could result in a new imbalance in about three to four years when demand will exceed supply, he said.

This may have "serious long-term consequences" for the global market as new upstream projects that could help secure stable oil production after 2020 would be "frozen" or delayed, he added. As a result, "the confidence in the sector's ability to meet global demand, which was built on technological breakthroughs in recent years, could be undermined," Teksler said.

His comments are similar to those made by the International Energy Agency, which estimated in November that non-OPEC supply may peak before 2020 at just above 55 million b/d, owing to upstream spending cuts. These are put at more than 20% in 2015, among the deepest in history, according to IEA executive director Fatih Birol.

"An annual $630 billion in worldwide upstream oil and gas investment – the total amount the industry spent on average each year for the past five years – is required just to compensate for declining production at existing fields and to keep future output flat at today's levels," the IEA said in its annual long-term World Energy Outlook published In November.

"The current overhang in supply should give no cause for complacency about oil market security," it added. The IEA said oil prices would move higher as world oil markets work off the current excess supply and return to balance at $80/b in 2020.

Russia wants an active international discussion to develop "a joint agenda" to meet the challenges facing the oil market, Teksler said. "Developing a joint agenda for the world energy sector, which would unite rather than divide energy exporters and importers, is a key task of the dialog," he said. Such an agenda should be based on the long-term interests of energy producers and consumers as no one wants either supply or demand shocks, he said.

This should include developing international cooperation in the sphere of new technologies for energy production, transportation and storage, raising industry efficiency and strengthening regional market integration, he said. Russia is already involved in energy dialogs with OPEC and China as well as the EU, despite current political disagreements, he added.

Energy minister Alexander Novak said November 16 that Russian and OPEC experts are to continue talks in mid-December after reaching such an agreement in the latest technical meeting between OPEC and non-OPEC producers October 21. Speaking on the sidelines of the G20 meeting in Antalya, Turkey, he also reiterated that Russia would be ready to take part, if invited, in consultations with OPEC ahead of a ministerial meeting of the producers' group on December 4, according to media reports.

In recent months, Russia and OPEC have intensified consultations but have ruled out possible coordinated actions to cut output, with Novak repeatedly saying artificial moves to cut production would have only short-term effects. Teksler said Russia sees its role "not in balancing the hydrocarbons market but securing a stable basic supply, both to the European and Asian markets."

Indian oil product demand surges in October

India's appetite for oil products surged 17.5% year-on-year to 15.22 million mt (3.85 million b/d) in October – a second consecutive month of double-digit growth – as buoyant demand from the household, transport and industrial sectors lifted consumption, a trend that may find support in coming months, owing the country's healthy economic outlook.

India's GDP grew 7.3% in the last financial year (April 2014-March 2015), and senior government officials have said New Delhi is aiming for 8%-10% growth in the current financial year.

Domestic sales of diesel, which accounts for about 40% of India's oil products demand, grew 16.3% year-on-year in October to 6.34 million mt, up 7.75% from September, provisional data from the Petroleum Planning and Analysis Cell showed.

Diesel sales hit a high of 6.5 million mt in April and then tapered off during the monsoon months, before recovering in September. After taking the rainy season into account, India's cumulative diesel demand in January-October was 60.1 million mt, 5.17% higher from the year-ago period.

In addition to diesel, all other products, except kerosene, posted double-digit growth in October. "Strong growth is taking hold right across the barrel," the International Energy Agency said in its latest industry report, adding that increased economic optimism, an ambitious road building program, lower oil prices and strong vehicle sales were fueling demand in the South Asian nation.

In January-October, India's oil overall products demand rose 8.95% year-on-year to 146.17 million mt, or 3.77 million b/d. Gasoline sales rose 14.48% year-on-year to 1.85 million mt. In the 10-month period, gasoline sales rose 16.62% to 17.5 million mt.

Gasoline sales have received a boost from the removal of diesel subsides late in 2014, prompting a shift towards petrol-driven vehicles, which triggered unusually high level of imports earlier this year. "Petrol demand has been particularly robust in India, helped by the fall in prices and the structural shift away from diesel in passenger vehicles," Credit Suisse said. In September, gasoline sales jumped to a record high of 1.9 million mt, up 25% year-on-year.

Keystone XL rejection prompts oil sands CO2 initiative

Canada's Alberta province has announced a new "climate leadership" plan that includes a cap on greenhouse gas emissions by oil sands producers. The move follows a US rejection of the controversial Keystone XL pipeline, which would have taken 830,000 b/d of Canadian and Bakken crude to Steele City, Nebraska, where it would have connected with an existing pipeline to the US Gulf Coast.

The reason given for the proposal's refusal by the US was that sufficient takeaway capacity, either by pipeline or by rail, already exists. However, environmental issues look a more likely explanation. Opponents of the project argued that it would lead to increased Canadian oil sands output, harming the environment and contributing to global warming. US President Barack Obama rejected that argument, saying the 1,600-mile project would not be "the express lane to climate disaster".

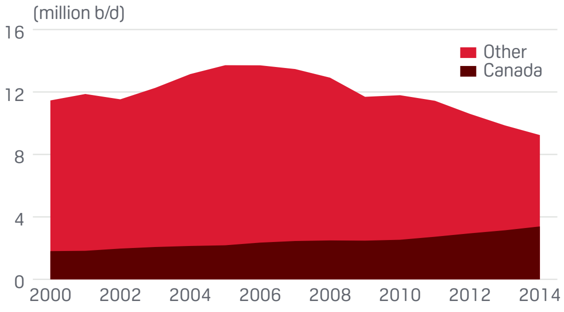
Alberta's initiative is an attempt to reduce concerns about the greenhouse effects of oil sands production, which the Keystone XL rejection and concerns expressed in Europe indicate is a threat to securing export markets for the crude. The cap on emissions has been set at 100,000 mt/year, Alberta's Premier Rachel Notley said. There is currently no cap and the province's near 2.3 million b/d of raw bitumen output produces 70,000 mt/year of CO_2, she said.

Alberta will also raise the price of carbon paid by emitters to the province from the current C$15 ($11.20)/mt to C$20/mt from January 2017 and C$30/mt a year later, she said. In addition, the government will introduce a Carbon Competitiveness Regulation in 2018 that will set a price on carbon for industrial emissions, a five-member panel set up by the province said.

The panel was tasked with suggesting ways to reduce greenhouse gas emissions without discouraging oil sands investments. "This is the day we start to mobilize the oil industry and stop denying there is an issue [with emissions]," Notley said. "We are turning around a mistaken policy of the past and will put capital to work in green infrastructure."

Notley said of the Keystone XL decision: "That decision underlined our need to improve our environmental record and reputation and highlighted that we need to do a better job." she said.

US IMPORTS OF CRUDE OIL



Source: EIA

TransCanada withdrew its route application filed with the Nebraska Public Service Commission, following the US rejection of the plan, but could refile a new application after US presidential elections are held in late 2016.

Chairman of oil sands producer Canadian Natural Resources, Murray Edwards said, "The targets [for reducing emission levels] are ambitious and come at a difficult time for the industry, but producers will focus more on innovation." Alberta's oil sands producers are already investing about C$1.2 billion in 814 technologies, he added.

Rejection of Keystone XL leaves Western Canada's oil industry in a quandary. Producers have for years bemoaned a lack of takeaway pipeline capacity that has seen Canadian crudes trade at substantial discounts to benchmark prices. In early November, Western Canadian Select was priced at a $14.70/barrel discount to the calendar-month average of the front-month NYMEX light crude oil futures contract.

Moreover, despite low prices and a slowdown in investment, the Canadian Association of Petroleum Producers expects Canadian production to grow to 3.8 million b/d in 2016. Pipeline operator and developer Enbridge predicts that Alberta's oil sands producers will need an additional 450,000 b/d of new takeaway capacity for their Western Canadian heavy crude by 2019, with that figure rising by another 500,000 b/d in a high oil price scenario.

The development of Canada's oil and gas industry is predicated on the basis that the US market would continue to grow and that it would be in a prime position to benefit. In particular, US Gulf Coast refineries are configured for heavy crude, which Western Canada produces, rather than light shale oil. US refiners would prefer a supply chain based on Canada rather than alternatives such as Venezuelan and other heavy Latin America crudes.

The Keystone XL pipeline, which had been slated to come online around 2019, had it received a presidential permit, would have served as a significant release valve for Canadian producers and improved US supply security.

In its absence, attention will turn more directly to alternative pipeline proposals that offer access to new markets for Western Canada's oil producers beyond the US. These include TransCanada's 1.1 million b/d Energy East pipeline, Kinder Morgan's 890,000 b/d TransMountain Expansion and Enbridge's 525,000 b/d Northern Gateway project.

TransMountain Expansion and Energy East, which would both take Western Canadian crude to the country's Atlantic coast, are slated to start up in 2018 and 2020 respectively. Northern Gateway would ship crude from Alberta to British Columbia, giving it access to the Pacific basin.

However, both Energy East and TransMountain Expansion have still to pass Canadian regulatory reviews. Elections in October returned a Liberal Party government at the federal level, which has promised greater scrutiny of such projects. In addition, TransCanada announced in early November that it was scrapping a proposal for an export terminal in Quebec, owing to local opposition. Canadian producers must now put their faith in at least one of these three projects being built.

Higher ethanol prices fail to dent Brazilian demand

Brazilian hydrous fuel ethanol demand in October rose 45% year-on-year to 1.75 billion liters, the fourth monthly consumption record in a row, according to data released by the National Petroleum Agency (ANP). October's total was also 7% higher than consumption in September.

Higher ethanol prices in October had been expected to reduce domestic hydrous fuel ethanol demand, leading to an increase in consumption of anhydrous ethanol, which is mixed with gasoline. Platts assessed domestic hydrous ethanol prices in Center-South Brazil at Real 1,950/cubic meter ($527/cu m) November 24. The Platts hydrous ethanol assessment on October 30 was Real 1,870/cu m and Real 1,650/cu m on September 30.

When Brazilian sugarcane growers association UNICA released a report showing strong domestic hydrous ethanol sales – the data included fuel and industrial ethanol sales – the market was unsure whether sales were for consumption in October or whether distributors were stocking up November too. But ANP's new figures prove domestic demand for both products remains strong.

Both hydrous and anhydrous ethanol prices have surged recently for several reasons – a 6% increase in gasoline prices in late September, fewer offers on the spot market with mills storing ethanol for the inter-crop period that starts in December, and heavy rain disrupting the sugarcane harvest.

Hydrous ethanol is used as a standalone biofuel (E100) in flex-fuel vehicles. To be competitive with gasoline in Brazil, the E100 price has to be at most, 70% of the gasoline price. In October, hydrous ethanol prices at the pump in the six largest states for consumption averaged 67% of the gasoline price, compared with 64% in September and 68% in the same period last year, ANP data show. The six states represent about 85% of domestic demand and lie in the key Center-South sugarcane region.

Drivers have benefited as domestic prices for hydrous fuel ethanol in the Center-South were under pressure for most of the sugarcane season, which began in April as millers boosted hydrous ethanol production, owing to low sugar prices. Parity to gasoline has averaged 72% in November, leading Platts unit Kingsman to estimate that hydrous consumption in November could drop by 10% month-on-month. However, consumption is usually high in December, owing to end-of-year holidays.

Hydrous prices at the pump are almost Real 1/liter below gasoline levels, meaning consumers are still likely to prefer ethanol. But Kingsman expects that if ethanol rises to 75% of parity, consumers may start switching back to gasoline.

Anhydrous consumption in October reached nearly 938 million liters, up 5% from previous month, but down 6% year-on-year. Gasoline C is blended with 27% anhydrous ethanol. Gasoline C consumption in October totaled 3.47 billion liters, up 5% from September, but down 13% year-on-year. Usually, when hydrous demand increases from one month to the next, gasoline C demand remains stable, or drops, according to Kingsman analysis.

January through October hydrous ethanol consumption in Brazil increased 42% year-on-year to 14.9 billion liters, while anhydrous demand totaled 9 billion liters, down 2% year-on-year, according to the ANP data.

Gazprom forecasts gas output decline in 2015

Russia's Gazprom has reduced its forecast for natural gas output in 2015 to 427 Bcm, the first time this year it has forecast that production will drop. The new forecast means Gazprom will be hit by the dual impact of lower gas prices and lower volumes this year, as domestic demand stuttered and uncertainties continue over the future gas demand landscape in Europe, its main export market.

In its third-quarter earnings statement, Gazprom again revised down its expectation for full-year gas output, with the latest projection representing a drop of 3.8% compared with production in 2014 of 445 Bcm. Gazprom has reduced output forecasts for this year several times, on the back of lower Ukrainian shipments and warm weather at the beginning on 2015. At the same time, Gazprom reported a daily output record of 1.556 Bcm October 22 as the peak heating season began and exports to Ukraine ramped up.

The latest forecast is in stark contrast to Gazprom's earlier expectations for its production this year. In the spring, Gazprom forecast that gas production would rise strongly in 2015 to around 485 Bcm, returning output to levels last seen in 2013. However, that was before Ukraine halted all purchases of Russian gas between June and October.

Gazprom in May reduced its forecast to 450 Bcm and then in August revised it down again, saying the company was planning to produce gas at the same level as last year, close to 445 Bcm.

Despite the decline in both price and expected volumes, Gazprom in October revised upward its 2015 investment program by almost a third compared with a previous forecast. The company's new plan for this year foresees spending of Rb1.043 trillion ($16.8 billion), up nearly 30% in ruble terms and about 18% in dollar terms, compared with the program agreed at end-2014. The 2015 plan is also well up on last year's investments, which totaled Rb805.4 billion.

According to Gazprom deputy CEO Alexander Medvedev, supplies to Europe and Turkey will be much higher than anticipated at close to 160 Bcm in 2015. Earlier estimates were around 153 Bcm – after stronger-than-expected sales in the second and third quarters. That suggests that it is a combination of reduced exports to Ukraine and lower domestic demand within Russia that has triggered the forecast downgrade.

Low oil price proves catalyst for Australian M&A activity

After more than a year of depressed crude prices, oil and gas companies are making Australia a takeover hotspot, seeking to reap rewards from cheaply priced assets when markets ultimately rebound. If some of the deals – the major ones centered around Santos and Oil Search – go through, they are expected to shake up the region's oil and gas sector.

"Every major downturn in oil price over the past 50 years has been accompanied by an M&A cycle," Bernstein Research analyst Neil Beveridge said. "While it may still be too early to call this the start of a M&A cycle, any increase in M&A activity will suggest that the industry believes that the bottom of the cycle is approaching."

LNG is one area where there has been a significant increase in M&A activity this year, with more than $100 billion, or half the oil and gas sector's total, in proposed deals. From a level of close to $19/MMBtu in early 2014, LNG prices have plunged more than 60% on the back of growing supply in the Pacific and weak demand from traditional Asian buyers.

The Platts LNG netback FOB Australia, which rose to $18.86/MMBtu February 14, 2014, fell to the low $6s/MMBtu in February this year, and was $6.95/MMBtu on November 3. Despite the near-term cyclical downturn, interest in LNG has increased as buyers look for assets with long-term growth potential, Beveridge said. "We see LNG as one of the more attractive growth sub-segments in the industry over the coming 30 years with industry growth of 6-7% as demand shifts to lower-carbon fuels," he added.

Activity picked up in September when Woodside launched an A$11.6 billion ($8.4 billion) takeover bid for Papua New Guinea-focused Oil Search. Woodside's interest in Oil Search centers on its LNG assets, particularly its 29% stake in the PNG LNG project, operated by ExxonMobil. The proposal highlights the attraction of PNG assets that sit at the lower end of the cost curve, according to Bernstein.

PNG LNG started up several months ahead of schedule and has been operating at a rate of 7.4 million mt/year during the third quarter, well above its nameplate capacity of 6.9 million mt/year.

Oil Search operates all of PNG's producing oil fields, but the addition of PNG LNG has changed its output profile. Production from the project is set to boost Oil Search's output in 2015 to between 27 million and 29 million boe, from 19.27 million boe in 2014 and 6.74 million boe in 2013.

Woodside's overtures have so far been rejected by Oil Search, whose Managing Director Peter Botten has said the offer was not up to expectations. Woodside CEO Peter Coleman has said he had little appetite to raise the bid.

Separately, Santos has become the subject of a takeover bid. Investment fund Scepter Partners, which has links to the royal families of Brunei and the United Arab Emirates, surprised the market in October by making a A$7.14 billion offer for the Australian company.

Like Oil Search, Santos has rejected the offer, but the company is in a relatively weaker position, having seen its share price fall in the wake of the oil price crash, from more than A$15 in early September 2014 to below A$4 on September 30 this year.

There's also been an upturn in M&A activity among Australia's juniors. In October, Beach Energy and Drillsearch Energy unveiled plans for a merger that would create a mid-cap oil and gas producer valued at around A$1.17 billion and with production of 12.1 million boe. The deal, set to be completed next February, would combine the two companies' overlapping assets in central Australia's Cooper Basin, providing cost savings of around A$20 million annually.

Cooper Basin is Australia's largest onshore petroleum province and has produced more than 6 Tcf of gas since operations began in 1969. Currently, there are around 190 gas fields and 115 oil fields producing in the basin.

Armour Energy, which is active in the unconventional oil and gas sector, has also attracted interest from both a privately-owned Chinese group Landbridge and US shale pioneer Aubrey McClendon's American Energy Partners. American Energy Partners in September signed an agreement to spend up to $130 million exploring Armour's tenements in the Northern Territory's McArthur Basin over the next five years, with a view to earning a 75% stake in the area. That deal was subsequently scuttled when Landbridge raised an August offer of A$0.12/share to A$0.20/share.

However, McClendon has come back with a sweetened farm-in proposal, linked to a partial takeover offer. Should the deal receive shareholder approval, AEP would emerge with a 19.23% stake in Armour. Interest is also centered on potential plays for other onshore producers such as Cooper Energy and Strike Energy.

Meanwhile, at the other end of the scale, the Australian Competition and Consumer Commission gave its unconditional approval in November for the proposed $70 billion merger between Shell and BG Group, leaving just two more regulatory hurdles to be cleared before the massive deal can proceed.

The go-ahead from the ACCC was the third of five regulatory approvals that were pre-conditions to the merger and follows clearances already obtained from the Brazilian competition authority, CADE, on July 24 and the European Commission on September 2. The two approvals still required for the merger, which must also gain support from Shell and BG shareholders, are from the Australian government's Foreign Investment Review Board and China's Ministry of Commerce.

The ACCC's main point of interest was Shell's 50% stake in Queensland-based coalseam gas company Arrow Energy, which it owns in a joint venture with PetroChina. Arrow's gas is a potential source of future supply for the Queensland Curtis LNG project on Curtis Island in Gladstone, which is operated by BG subsidiary QGC.

QCLNG has a capacity of 8.5 million mt/year at two production trains and started producing earlier this year. There are two other LNG projects on Curtis Island, the Santos-operated Gladstone LNG facility and Origin Energy's Australia Pacific LNG, with capacities of 7.8 million mt/year and 9 million mt/year, respectively.

LNG Croatia at critical juncture

LNG Croatia, the project vehicle that aims to build an LNG terminal on the island of Krk in the Adriatic, and provide the Balkan region with its first access to LNG, is soliciting investment. Industrial investors have until end-November to submit a bid to take part in the project, while equity investors have until December 31.

More than 20 years after a company was first formed to look at building an LNG import terminal on Krk, and following several years of inactivity, there is new momentum building behind the project. Southeast Europe is severely lacking in gas import options and is poorly interconnected. An LNG terminal in the Adriatic – combined with an improvement in the regional network – would offer important supply diversification for Croatia and the wider Balkan region.

Croatia and other countries in the region will also have looked at Poland and Lithuania's success in constructing LNG terminals and the leverage this option has provided them in negotiations with Russia. For Moscow, the project represents yet another encroachment on fomerly secure markets.

LNG Croatia is a joint venture between Croatia's gas TSO Plinacro and utility HEP. The planned capacity of the terminal is about 6 Bcm a year, in comparison with national demand of about 2.6 Bcm, two-thirds of which is met domestically.

According to the latest project design, Krk LNG will have two 180,000 cu m storage tanks and will also be able to anchor special purpose LNG vessels, as well as handle LNG refilling, storing and reloading. The terminal's reloading facility will also be able to re-fill LNG to smaller, special purpose LNG vessels and load LNG trucks.

EU and Croatian government support for the project is likely to increase investor confidence. The project was included in the European Energy Security Strategy document published in May last year. This program aims to promote resilience to energy supply shocks and disruptions to energy supplies in the short term, and reduce dependency on particular fuels, energy suppliers and routes in the long-term.

The Krk terminal is also on the EU's Project of Common Interest list – a scheme designed to help create an integrated EU energy market – and was granted financial aid for studies into its economic viability. In July this year, the terminal was designated as "strategic" by the Croatian government, and in September it received a valid location permit – a key stage in the project development, according to Matej Zovkic, assistant director of LNG Croatia.

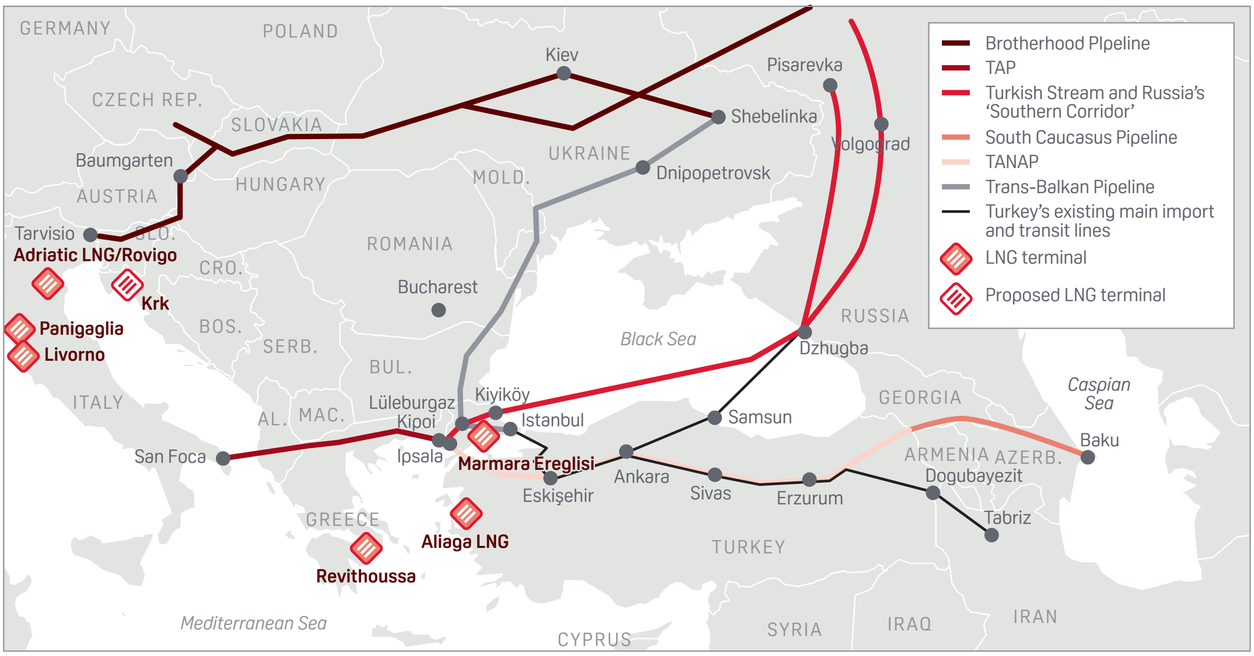
Progress, hitherto, has been painfully slow. The first incarnation of the operating company – Adria LNG – was founded in mid-1995 by Austria's OMV, Czech Transgas, Slovakia's SPP, France's Total and the gas transportation companies of Slovenia, Bosnia, Croatia and Hungary. It has been through several changes in ownership since then, and its design capacity has been considerably lowered.

The scheme was shelved in 1997 because of a lack of consumer interest and convincing independent arguments over feasibility. OMV then revived the project in 2005 with plans for a facility with import capacity of 10 Bcm/year that could then have been expanded to 15 Bcm/year.

However, the project was effectively suspended again in 2010, owing to a surge in LNG shipments into Europe and a big fall in European gas demand. Shareholders at the time included OMV, Total, Germany's E.ON and Croatia's Geoplin. RWE had also been a partner, but dropped out in 2009.

Doubts remain about the viability of Krk LNG. On the plus side, analysts say the island is suitable for a terminal from a technical point of view as it has a deep natural harbor. Krk is already home to an oil terminal, and an LNG terminal would likely be located somewhere in its vicinity. However, the project partners still have to reassure

TURKISH STREAM AND THE SOUTHERN GAS CORRIDOR



Source: Atlantic Council

environmental groups that the terminal would not impact the island's ecology or its role as a tourist destination.

In addition, Krk LNG faces competition from three other major projects that aim to supply southeast Europe. The first, and most advanced, is the Southern Corridor (TANAP/TAP) project to bring gas from Azerbaijan to southern Europe. Then there is TurkStream, the planned 32 Bcm/year line from Russia via Turkey. And most recently, Hungarian gas pipeline operator FGSZ and Romanian counterpart Transgaz announced that they are planning a 4.4 Bcm/year pipeline to export Romanian gas to Europe. Investors will have to balance the support given the project by the EU and Croatian government against the possibility that LNG in Croatia might prove surplus to requirements.

Colombia to import Venezuelan gas from January

Ending decades of self-sufficiency in natural gas supply, Colombia in January will begin importing 39 MMcf/d of gas from neighboring Venezuela. Colombia expects to need more than the initial volumes and is negotiating an increase in supply.

The gas imports will fill a supply gap, which is expected to last until end-2016, when a $140 million LNG terminal under construction near Cartagena is scheduled for completion. The facility is being built by a group of energy utilities to insure fuel for their power plants. The new LNG facility will have the capacity to process 433 MMcf/d, or about 40% of Colombia's current average consumption.

Gas imports could increase significantly in coming years, officials have said, partly because of declining reserves and the expected near term impacts of the El Nino weather phenomenon. Climate change may also force Colombia to divert more gas to thermoelectric power plants to make up for less electricity generated from hydropower plants, owing to reduced rainfall.

State oil and gas company Ecopetrol reported last year a promising natural gas find at its Caribbean offshore Orca-1 well drilled with Spain’s Repsol and Brazil’s Petrobras, but according to Ecopetrol CEO Juan Carlos Echeverry, production from the well, if it proves commercially viable, remains several year away.

The planned January imports of natural gas amount to about 3.5% of Colombia's average daily gas consumption of 1.1 Bcf. Colombia has been self-sufficient in natural gas since significant finds were made in the northeastern Guajira peninsula by US major Chevron, which remains the operator as Ecopetrol's partner. Further gas discoveries in the Cupiagua-Cusiana complex added to its gas independence.

However, in an earnings release in November, Ecopetrol reported that its natural gas output over the third quarter had averaged 128,900 boe/d, down 6% from the 137,100 boe/d over the same three months last year. Ecopetrol's overall production, including crude and products, over the quarter averaged 740,900 boe/d, down 1.8% from the 754,800 boe/d produced in third-quarter 2014.

In an interview given to *El Tiempo* newspaper, Echeverry admitted that Ecopetrol finds itself in "choppy waters," in the short term. Echeverry also detailed the company's efforts to cut costs and improve cash flow, amid a softer crude price environment. He said 13,000 contract employees have been let go this year, a reduction of 28% from the 47,000 contract workers employed a year ago.

By year-end, Ecopetrol will have reduced annual costs by roughly $700 million. Much of those costs have come from renegotiating contracts with the 4,200 contractor firms doing business with the company, cuts which Echeverry admitted have generated ire among suppliers.

The pain is also being felt by the Colombian government. As a result of the price declines, the government will receive 3 trillion pesos (about $1 billion) in taxes, royalties and dividends from Ecopetrol this year, down from 23 trillion pesos in 2013, Echeverry said.

Kuwait receives bids for stalled Jurassic gas project

Kuwait has received bids for three major projects worth more than $4 billion for the second phase of its non-associated gas development known as the Jurassic gas project, government officials said in November. Three companies bid for the contracts to build facilities with the capacity to produce 120,000 b/d of wet crude and more than 300 MMcf/d of sour gas from the north of the country, according to the Central Tenders Committee, which oversees all major public tenders in Kuwait.

The bidding companies are oil field services giant Schlumberger, Saudi Arabia's Al-Khorayef Group and Kuwait's Spetco International. Schlumberger submitted the lowest bid of Dinar 1.317 billion ($4.3 billion) for production facilities at the West and East Raudhatain fields and the Umm Niqa and Sabriya fields.

Bids from Al-Khorayef and Spetco were higher, but Kuwait Oil Co. or KOC will not award a single contractor more than one of the contracts. However, some contractors in Kuwait said KOC was now scaling back its plans and may only award a single contract.

The long delayed Jurassic gas project was resurrected in September after been stalled since 2010 when the contractor for phase one failed to secure financing. Local company Kharafi National was awarded a $1.56 billion contract in 2010 with the aim of producing 100,000 b/d of crude and 510 MMcf/d of gas.

A re-tender for phase one is still on the cards, but unlikely to be issued until early 2016, sources in Kuwait said. It was slated for completion by 2017, but the contract was canceled late last year after three years of delays.

The project is critical to Kuwait's hopes of boosting non-associated gas production to approximately 600 MMcf/d by 2020 and as much as 1 Bcf/d by 2030. Current production is just over 140 MMcf/d. The rest of Kuwait's 1.4 Bcf/d of gas comes from associated fields, meaning production rates are tied to crude oil production.

Cheap oil underpins Indonesian coal production

Falling fuel costs have cushioned major Indonesian thermal coal suppliers from sharply lower coal prices this year, but their smaller-than-expected output cuts have cast doubts on any possible recovery in prices going into next year. Expectations were rife that Indonesia would sharply cut thermal coal output to address an oversupplied market, but major Indonesian miners holding Coal Contract of Work mining licenses have either maintained or made only marginal cuts to production forecasts.

Given persistent oversupply and dwindling Chinese demand, market participants are skeptical that any output cuts from these miners will be significant enough to give a boost to coal prices, which have fallen nearly 20% this year.

"We estimate the impact of global supply rationalization at about 30 million mt of seaborne coal, excluding Indonesian low calorific-value coal," Standard Chartered Bank analyst Serene Lim said in a note. "We believe this supply response is insignificant in a structurally oversupplied market." Lim does not expects any coal price recovery until end-2017 at the earliest.

In the third quarter, major Indonesian miners largely reported profits despite a slump in revenue as lower oil prices helped keep production costs under check. "The downward trend of the oil price has contributed to curb the company's mining operation and logistics costs," Indonesian coal miner Indo Tambangraya Megah said in its third-quarter report. Over January-September, the company produced 21.5 million mt of coal, in line with its annual output target of 28.7 million mt.

Lim said cost-cutting measures have largely been exhausted. "We expect operating margins to be under intense pressure in 2016, especially for Indonesian producers," she said. According to Lim, Indonesia's January-August thermal coal exports slumped 18% year-on-year to 211 million mt. "The producers that scaled back were mostly those with mining business licenses (IUPs), not those with Coal Contract of Work permits," she said.

CCoW permit holders, which account for 70%-80% of Indonesia's total coal production, are bound by contractual production commitments. "Under the contractual obligation, those CCoW permit holders are unable to make major changes to supply and therefore trimmed production only marginally, 1%-2% to date. On the other hand, IUP holders on average have cut about 20% of their output this year", Lim said.

Lim expects Indonesia to export 330 million mt in 2015, down from 407 million mt last year, including supply from illegal operations. She expects exports to falling further to 290 million mt in 2016. "This [estimate] assumes that illegal miners have been completely priced out at this price level and have shut down," she said. In September, Citibank analysts forecast total Indonesian coal exports at 283.1 million mt in 2015, down from 304.1 million mt a year ago. For 2016, Citi expects exports to drop further to 274.6 million.

While the average selling price for major Indonesian coal miner Adaro Energy fell 14% year-on-year in the first nine months of 2015, Adaro's cash cost also fell 13% to $28.61/mt in the same period, mainly owing to lower oil prices. Fuel cost fells 39% to the low 50 cents/liter, the company said. Fuel cost accounts for about 25%-30% of Adaro's total production cost.

Another Indonesian coal miner PT Harum Energy said average sales price in the first nine months of 2015 stood at $53.10/mt, down about 15% from the same period a year ago. In the first nine months of the year, the FOB vessel cash cost was $36/mt, unchanged from the second quarter, but down 17.3% from $43.50/mt in the nine-month period a year ago, the company noted. Sales volumes stood at 3.7 million mt in the nine months ended September, sharply down from 6.1 million mt in the same period last year.

Colombian thermal coal exports hit five-month high

Colombian October thermal coal exports rose to a five-month high of 7.092 million mt, up 15.6% year-on-year and marginally higher month-on-month, data from Colombian shipping agent Deep Blue showed. The Netherlands remained the main destination, with 1.666 million mt shipped there in October, 11% higher year-on-year and 1% lower than September.

Coal shipments to Turkey rose to a four-month high of 1.036 million mt, up 29% year-on-year. These were followed by the US with 631,607 mt and Brazil with 603,453 mt, year-on-year rises of 68% and 71% respectively. Exports to Portugal more than doubled year-on-year to 326,825 mt in October.

Colombian coal sent to the UK dropped to its lowest level in three months at 331,094 mt, down 56% year-on-year. Shipments to Spain and Chile also fell year-on-year, with Spain buying 488,562 mt, down 13%, while exports to Chile were down 35% to 313,913 mt.

Puerto Bolivar terminal, owned by the country's largest miner Cerrejon, exported 2.942 million mt of coal in October, up 13% year-on-year and down 10% month-on-month.

Puerto Drummond shipped 2.41 million mt, 6% higher on the year, but 6% lower month-on-month. Puerto Nuevo, owned by Glencore unit Prodeco, sent 1.354 million mt, 21% higher than October 2014 and down 10% on the month.

Shipments from third-party port Carbosan-Sociedad Portuaria de Santa Marta more than tripled year-on-year to 367,336 mt, but slipped 4% month-on-month.

The monthly October average for Platts FOB Colombia 6,000 kcal/kg NAR thermal coal price was $48.56/mt, down from September's $49.13/mt. The weekly FOB Colombia 6,000 kcal/kg NAR price was assessed at $50.35/mt November 20, up 65 cents/mt week-on-week.

Ukraine struggling to pay for gas imports

Russia's energy minister, Alexander Novak said November 24 that Russia would halt supplies of natural gas to Ukraine after Kiev stopped pre-payments for future deliveries. However, the move will have limited impact on Ukraine as Kiev said November 23 that it would not import any more Russian gas for the remainder of 2015. Imports fell to minimal levels in November as Ukrainian gas storage has reached a comfortable level ahead of winter.

Russia's decision came as tensions between Moscow and Kiev again rose after electricity supplies from Ukraine to the annexed region of Crimea were halted due to sabotage. Novak said Russia might consider retaliation against Ukraine, including limiting coal supplies. "Possibly, we could [...] stop deliveries of coal by our companies, which supply coal to Ukraine's power stations," Novak was quoted as saying by local media.

Novak said that such a move was unlikely to have any effect in the near term because Ukraine had sufficient coal stocks and domestic production. "But [at some point] there will be a deficit," he was quoted as saying by *RIA Novosti*.

Ukraine imported about 2.35 Bcm of Russian gas between October 12 and November 21, mostly addressing concerns over the need to replenish underground gas storage facilities ahead of winter. However, weaker domestic demand for gas, caused by shutdowns of many manufacturers in its Donetsk and Luhansk regions due to the pro-Russia separatist uprising, led to greater-than-expected gas stocks.

"As of right now, consumption is considerably less than we had expected," Ukraine's energy minister, Volodymyr Demchyshyn, said. "That is why there is sufficient amount of gas in the storage facilities that we can use without resorting to [new] imports [from Russia]."

Ukraine had 16.52 Bcm of gas in its underground gas storage facilities as of November 22, down 1.9% from November 15, according to Naftogaz Ukrayiny, the national energy company. Ukraine is expected to have at least 16 Bcm of gas in storage at end-November, Demchyshyn said.

Ukraine will continue to import European gas at the same robust pace and at lower-than-Russian gas prices, he said. Ukraine can completely rely on imports of European gas via Slovakia to meet winter demand, according to Platts analysis.

However, Ukraine also said November 24 that it may postpone for a month imports of European natural gas because the European Bank for Reconstruction and Development had delayed disbursement of $300 million loan, according to Yuriy Vitrenko, a senior official at Naftogaz Ukrayiny. The loan has been not been disbursed because the government has delayed formal approval of reform measures streamlining the operations of Naftogaz and making them more transparent. "This gas was supposed to be purchased in November. God help us to buy this gas in December," Vitrenko said.

Naftogaz and EBRD signed the $300 million loan agreement October 23 in Berlin in the presence of German Chancellor Angela Merkel and Ukrainian Prime Minister Arseniy Yatseniuk. Naftogaz was supposed to use the funds to purchase about 1.1 Bcm of gas from European suppliers in November.

The measures include a program of Naftogaz corporate restructuring, the creation of a supervisory board of independent and qualified directors, the introduction of internal audit, compliance, anti-corruption and risk management functions and an ownership and governance structure in line with best international practice.

IEA defends renewable energy forecasts

International Energy Agency Director Fatih Birol was forced in November to defend the organization's success in forecasting the growth in renewable energies, having been accused of underestimating the sector's rapid development and its impact on the global energy mix.

Among those critical of the IEA's record on renewables forecasting is the UK-based financial think-tank Carbon Tracker Initiative. In October, it said that the IEA had been "hugely conservative" in the past in its assessment of renewable energy growth. It said that the speed and scale of advancements in the competitiveness of renewable energy technologies were exceeding expectations.

Speaking in London at the launch of the agency's latest World Energy Outlook, Birol said the IEA had been extremely accurate in its previous forecasts on renewables. "95% of our projections on renewables were completely right – for hydro and wind," Birol said. He said it was only in solar power – which accounts for just 0.1% of the global energy mix – where the forecasts differed.

A recent study by Germany's Energy Watch Group looked at the IEA's forecasts from 1994-2014 and concluded that "projections for solar technologies and wind energy have been strongly underestimated." It said, "The WEO reports assume linear growth, whereas history shows an exponential growth for the new renewable energy technologies."

Birol said, "In our scenarios we look at the support of governments. If the support of governments increases, then we increase the projections", adding that the IEA's forecasts for solar power were accurate under one of its long-term assumption scenarios. "We make projections based on current policies. When policy changes, our numbers change," he said.

Birol added that if the policy environment shifts again before publication of its next WEO, the numbers would have to revised again. "We are happy to revise our projections [for renewables] upward if there is a policy signal," Birol said, pointing to the possibility of a global accord on climate change emerging from the COP21 talks in Paris.

LNG suffering from slowing Chinese energy demand growth

In a graphic illustration of China's slowing energy demand, the country's LNG imports fell by 18.2% year-on-year to 1.29 million mt in September, according to data from the General Administration of Customs. The September imports were also down 32.6% from the August level, and were the lowest for the month since September 2010, when China had only three operational terminals, compared with 12 now. Five of these received no LNG in September.

PetroChina received no deliveries during the month at any of its three terminals, the first time this has happened since the company's first terminal at Rudong started operations in 2011. CNOOC and Sinopec also reduced purchases. For instance, CNOOC reduced term purchases from Malaysia, with volumes from the country falling 58.4% year-on-year to 77,944 mt in September.

The majority of September imports appear to have come from suppliers who hold long-term contracts. The fuel was purchased at a weighted average price of $384.50/mt ($7.39/MMBtu). The monthly figure meant that China imported 4.63 million mt of LNG during third-quarter 2015, down 3.81% year-on-year.

The September figure also meant that LNG imports during the first nine months of 2015 were lower than in the same period of 2014. The 14.15 million mt of imports was not only 4.0% lower year-on-year, but also meant the country is running well behind the 38 million mt of term supplies contracted for calendar 2015, according to Platts data.

In contrast to the reduced LNG import figure for the month, Chinese gas production increased by 1.1% year-on-year to 9.58 Bcm in September 2015, although it fell by 8.1%, compared with the 10.42 Bcm reported in August, according to data from the National Bureau of Statistics. The figure meant domestic production during the first nine months of 2015 reached 93.1 Bcm, up 2.8% on a year-on-year basis.

With September pipeline imports also up 3%, China's gas consumption thus grew by 1% year-on-year in September, despite the fall in LNG imports. The monthly increase meant gas demand from January to September was 2.4% higher than in the same nine-month period of 2014.

The muted monthly demand increase might not seem exceptional given that the absolute level of gas demand, let alone the rate of growth in demand, is currently falling in many countries. But this is China, where GDP growth for third-quarter 2015 beat consensus expectations of a 6.8% rise year-on-year, and came in at 6.9% for the three-month period.

The low rate of gas demand growth compared with GDP is mirrored in the oil sector. September saw oil demand grow by only 0.4% year-on-year, while electricity demand actually fell by 0.2% to 456.3 TWh, according to data from the National Energy Administration.

The fall in power consumption took demand from January to September 2015 to 4,134 TWh, up only 0.8% year-on-year. This is in line with the China Electricity Council's demand growth forecast for calendar 2015 of 1%, a figure which has been revised down from an earlier estimate of 2%.

The fall in the electricity demand growth rate is a result of lower industrial consumption. The industrial sector, which accounted for 312.8 TWh of the 456.3 TWh of total demand in September, saw year-on-year consumption fall by 2.9%, whereas the residential and tertiary sectors both posted growth.

The low rate of growth in energy demand compared to the growth in GDP in part reflects changes in the composition of economic activity, with the government wanting to see more consumption-led growth. It also wants production to move away from energy-intensive smokestack industries toward higher-value manufacturing and services. Both these goals mean less energy is needed per unit of GDP.

On this point, Xianfang Ren, China Market Fundamentals Manager at BG, told an industry conference in Singapore in late October that China's lackluster LNG demand in 2015 partly reflected lower investment growth rates. These have fallen from more than 25% in 2010 to slightly over 10% in 2015. This in turn affects gas and LNG demand. "The gas market demand infrastructure basically is a mirror image of the economic structure...highly oriented to investment industry," Ren said, adding that about 60% of China's gas demand was directly related to investment.

But this only partly explains the travails of the Chinese LNG sector. Ren also noted that continued state control of energy pricing was impeding greater use of gas in general and LNG in particular. The solution would be to treat gas as a commodity not just a utility feedstock, Ren said, encouraging new entrants and creating more opportunities for different parties to capture value from the industry.

There was already progress on this front, Ren said, as the government has committed to unbundling the value chain and deregulating the gas price. But distortions remain, with changes implemented by the government in 2014 having left the price of gas higher than competing fuels, so LNG was now around 15% more expensive than LPG, Ren said.

One area where gas in general and LNG in particular has struggled in China is in power generation – the mainstay of the fuel's use in many countries. Pricing has been a key issue in a sector dominated by coal-fired generation, with gas being hit by the regulation of its own price, by low coal prices and by the limited use of environmental pricing mechanisms to offset the difference in emissions between the two fuels.

The commissioning of a large amount of wind and other capacity has also affected gas as well as other fossil fuels, especially at a time of sharply slowing growth in electricity demand. By end-September 2015 there was about 109 GW of operational wind capacity in China, up 28.3% from end-September 2014, while the 24 GW of nuclear capacity was 35.8% higher than a year earlier.

The influx of new capacity – with total Chinese generation capacity at end-September up 9.4% year-on-year at 1,385 GW – meant that fossil-fired plant operated for only 3,247 hours on average from January to September 2015. This was 265 hours lower than the average during the same period of 2014.

Hungary to go ahead with Pak II reactors, despite EU concerns

Hungary's government is to go ahead with the construction of two new reactors totaling 2,400 MW at the Paks plant, a project known as Paks II, despite fresh probes by the EU that question the legality and financial viability of the project in its current form. The European Commission opened an in-depth investigation November 23 to determine whether Paks II – financed by a Russian state loan – involves illegal state aid. News of the inquiry came just four days after the Commission launched a separate infringement procedure against Hungary, challenging the decision to award the Paks II project to Russia's Rosatom without a public tender.

The Hungarian prime minister's office said in a November 23 statement that it is prepared to demonstrate that Paks II involves no illegal state aid, and stressed that the project has "no alternative" when it comes to climate policy, security of energy supplies, and affordable electricity.

Hungarian Prime Minister Viktor Orban told state radio November 20 that Paks II would go ahead despite EU concerns. "It is Hungary's basic interest to operate and expand the nuclear power plant, or else electricity prices will skyrocket. Paks equals cheap electricity, so the government will execute the investment," he said.

At the center of the state aid investigation is a €10 billion ($10.6 billion) loan from Russia that will be used to finance the €12 billion project under an agreement signed last year. Repayment of the loan – at interest rates that rise from 3.95% to 4.95% during the period of the loan – would take 20 years, starting in the mid-2020s.

The Commission said in a statement November 23 the investigation would assess whether a private investor would have financed Paks II on similar terms; and if not, whether the state aid involved would lead to distortions on the Hungarian and EU energy markets. "The Commission has concerns that this investment may not be on market terms," it said, adding that it would "assess the business case ... in view of the EU's energy market projections."

Attila Aszodi, government commissioner in charge of the project, said at a November 17 press briefing that while the projected €55/MWh levelized production cost of electricity from the new units is well above today's market price, "we need to sell this power not now but in 2025, by which time we expect a much higher market price." He said prices would rise as the EU works to raise carbon costs for power plants, pushing today's cheap but high-emission coal-fired plants off the market.

In the public procurement infringement procedure, the Commission said it has concerns about whether the direct awarding of the project to Rosatom complies with EU procurement legislation, which calls for transparency and equal treatment. Hungary had been preparing since 2009 to call an international tender for the construction of the new Paks units, but cancelled those plans in early 2014 and went on to sign a bilateral treaty with Russia, naming Rosatom as the main contractor.

Janos Lazar, head of the Prime Minister's Office, said during a November 19 news conference that the government is ready to address the Commission's concerns – it has two months to respond to the formal notice – and continue constructive talks, but said the project "will go ahead" and Hungary is ready to turn to the European Court of Justice if needed.

Lazar said Hungary and Rosatom are prepared to issue public tenders allowing EU companies to bid for work on the project. On the suggestion that the probe questions the selection of Rosatom in the first place, Lazar said the Commission "had raised no objections in principle" to the bilateral treaty prior to its signing.

Lazar said the infringement procedure would not delay plans to start building the new units in 2018. Commission spokesperson Lucia Caudet declined to comment on news reports that the Commission had asked Hungary to suspend ongoing Paks II tenders for the duration of the probe, only saying it is partly "a matter of Hungary's own risk assessment."

19 GW of energy storage looks for EU plan inclusion

EU power grid operators will assess the costs and benefits of 23 energy storage projects totaling 19 GW planned to be online by 2028 in their next 10-year EU network development plan due in 2016, their formal body Entso-e said in November. The projects include pumped hydro, compressed air, batteries and molten salt technologies spread across 12 EU countries – Austria, Belgium, Bulgaria, Estonia, Germany, Greece, Ireland, Italy, Lithuania, the Netherlands, Spain and the UK.

Commissioning dates start in 2017 with Storelectric's 520 MW adiabatic compressed air energy storage project, which could deliver 6 GWh to the grid from full to empty, using salt caverns in Cheshire, northwest England. They end in 2028 with TIWAG's 1 GW Kaunertal pumped hydro storage extension project in Austria, which could deliver 152 GWh from full to empty.

Several of the biggest projects are in Spain, including Ingenieria Pontificia's 3.3 GW reversible pumped hydro storage Mont-Negre project in Zaragoza. This could deliver 7,511 GWh to the grid from full to empty, according to Entso-e's list.

Only power projects listed in Entso-e's 10-year EU network development plan can apply for EU projects of common interest status, which gives access to EU funding and faster local permitting. Energy storage is expected to play a key role in helping balance power flows in and between EU electricity markets as the EU moves to ever-increasing shares of intermittent renewables.

CO2 MARKET

EU CO2 prices edge higher in November

The price of carbon dioxide allowances under the EU Emissions Trading System edged slightly higher in November, on signs that the underlying energy markets had stabilized following weakness in October.

EU Allowance prices for delivery in December 2015 in the over-the-counter market averaged €8.49/mt ($9.04/mt) in the period November 2-23, compared with €8.40/mt in October, a month-on-month increase of 9 euro cent or 1.02%, according to Platts' daily closing assessments.

In the OTC market, prices rallied to an intra-month high of €8.63/mt at the close on November 19 – just short of October's high of €8.68/mt, which was the highest ever closing price for December 2015 EUAs since Platts started assessing the contract in December 2012. The gains in mid-to-late November followed a dip to as low as €8.33/mt November 9 as prices fell back on profit-taking from a strong month-long rally in October.

In the latest auction for carbon allowances, the UK government November 25 sold 3.123 million mt CO_2e at €8.56/mt. Total bids received were 6.285 million, giving a cover ratio of 2.01. On November 24, the EU sold 2.918 million mt CO_2 at €8.63/mt, equal to a 44-month high for European carbon auctions seen October 27.

The modest gains seen in November came as the underlying energy markets showed signs of stabilizing after weakness seen earlier in the month. German benchmark Cal 2016 baseload power prices fell as low as €28.55/MWh November 13 – the lowest year-ahead price in over 12 years – from as high as €29.80/MWh October 29, before recovering to €29.00/MWh by November 23.

API 2 thermal coal prices for year-ahead delivery into Northwest Europe on a CIF ARA basis fell as low as $45.75/mt November 12 from $48.70/mt on November 3, and showed a slight recovery to $46.00/mt by November 23.

The German clean dark spread – the profit margin on coal-fired power including the cost of carbon – drifted lower to €2.61/MWh November 18 from as high as €3.53/MWh October 8, but recovered slightly to €2.84/MWh by November 23, according to Platts data.

While a declining CDS is notionally bearish for carbon prices, EUA values remain in a long-term uptrend linked to regulatory reforms which are expected to tighten supply on an annual basis starting January 2019, eroding a long-term surplus.

Elsewhere, the COP21 climate talks in Paris were set to start November 30, with potential to shed clarity on the use of market-based approaches to reducing emissions, among many other elements. Any new deal could be a turning point in globally-coordinated climate action, and the long-term implications of the Paris summit could be far-reaching.

However, short-term reaction in the energy markets arising from any global deal may be relatively muted for two reasons. Firstly, most of the concrete elements of the talks – such as emissions reduction targets and dates – are already published within each country's national climate plan sent to the UN, so many of the key points making up the deal are already in the public domain.

Secondly, the markets may decide to wait until signs emerge that governments are following through on emissions targets and implementing meaningful changes including legislation, before assessing the implications for the emissions-intensive industries.

That said, there is always potential for surprises, and there is scope for governments, in time, to go beyond the pledges listed in their national plans this year. Expectations are that any new deal emerging in Paris would only be a core agreement, with further details that operationalize the deal to be further elaborated in future COP decisions, ahead of the treaty coming into force in 2020.

CO2 PRICE TREND (€/mt)

Source: Platts European Power Daily

PLATTS CO2 ASSESSMENT MONTHLY AVERAGES, NOVEMBER 1-23 (€/mt)

Delivery	High – Low	Midpoint
Dec-15	8.5081 – 8.4681	8.4881
Dec-16	8.5800 – 8.5400	8.5600
Dec-17	8.6831 – 8.6431	8.6631

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

Source: Platts European Power Daily

MARKET INDICATORS

Brent tests new lows

The price of international benchmark Dated Brent returned to a downward path in November, falling from $48.45/barrel October 28 to a low of $40.39/b November 16, a level not seen since February 2009 at the height of the global financial crisis. It had recovered somewhat to $44.01/b by November 23.

Although weekly supply estimates indicate US crude production is falling, field production data indicates only a moderate drop, with output estimated by the US Energy Information Administration at 9.324 million b/d in August, compared with a peak of 9.598 million b/d in April. Other non-OPEC output also remains strong, with Russia hitting post-Soviet highs repeatedly over the course of the year.

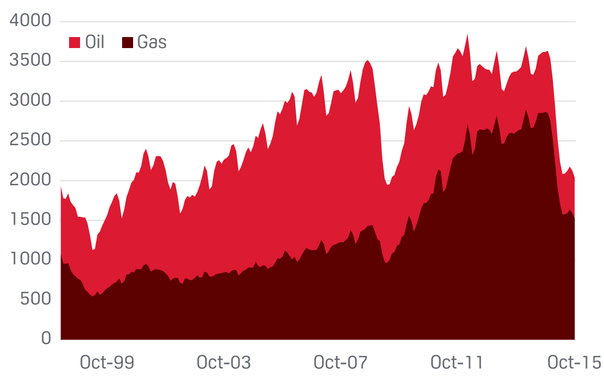
Stocks continue to rise and have reached record levels. According to the International Energy Agency, OECD oil inventories continue to grow counter-seasonally, jumping by 13.8 million barrels in September to almost 3 billion barrels. The IEA said preliminary data shows stable stock levels in October, compared with an average draw of 20 million barrels over the last five years.

Iran also appears to be making progress in complying with the conditions for lifting sanctions on its oil exports. At the same time, there appears to be no sign of any change in OPEC's strategy of high output in pursuit of market share, nor any sign that Saudi Arabia will reduce output to accommodate the expected increase in Iranian exports next year, if sanctions are lifted. High level talks have been held with Russia, but again there seems to be little indication of any material cooperation with OPEC.

For next year, the IEA sees demand rising by 1.2 million b/d, compared with an increase of 1.9 million b/d in 2015. It predicts that non-OPEC oil supply will contract by 600,000 b/d, implying either a higher call on OPEC or the beginnings of a drawdown in stocks. The EIA forecasts demand growth of 1.41 million b/d this year and 1.41 million b/d next year, with non-OPEC supply falling by 310,000 b/d.

OPEC crude output slipped to 31.08 million b/d in October, a drop of 120,000 b/d from September and the lowest level since May, led by falls in Saudi Arabia and Iraq. The Platts survey estimated Saudi output at 10.1 million b/d in October, the third consecutive month in which volumes have dropped, but despite a fall of 350,000 b/d since July, Saudi output has remained consistently above 10 million b/d since March.

GLOBAL RIG COUNT (monthly average)



Source: Baker Hughes

DATED BRENT ($/barrel)

1-year average: **55.07** 2-year average: **79.35**
5-year average: **97.63** 10-year average: **86.02**

Source: Platts Global Alert

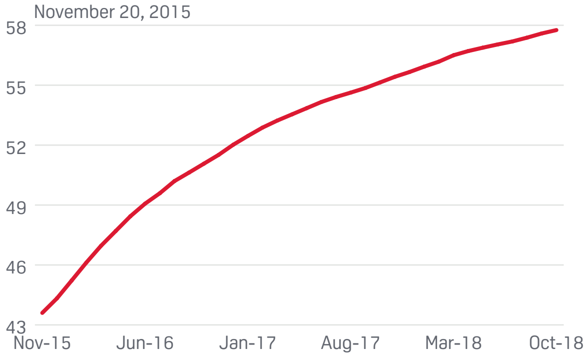
OIL FORECASTS (million b/d)

	Call on OPEC	Change in non-OPEC supply	OPEC NGLs	Total world oil demand	Change in demand	Supply/demand balance
November 2015 forecasts for 2015 (million b/d)						
EIA	30.96	1.15	0.15	93.86	1.41	-0.11
IEA	29.70	1.30	0.10	94.60	1.90	-0.50
OPEC	29.60	0.70	0.20	92.90	1.50	-0.60
November 2015 forecasts for 2016 (million b/d)						
EIA	31.19	-0.31	0.27	95.26	1.40	-1.44
IEA	31.30	-0.60	0.30	95.80	1.20	-1.50
OPEC	30.80	-0.10	0.20	94.10	1.20	-1.10

Supply/demand balance is the change in non-OPEC supply plus change in OPEC NGLs minus change in demand, a positive number implying greater supply than demand. OPEC provides data that combines OPEC NGLs and global biofuels, both appearing as one figure under 'Change in OPEC NGLs'. The EIA and IEA include global biofuels in their 'Change in non-OPEC supply' data.

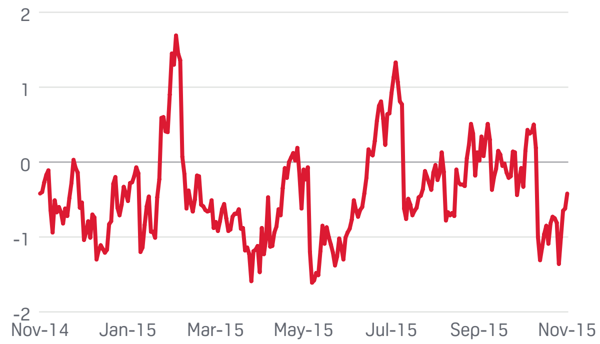
Sources: EIA, IAE, OPEC

PLATTS FORWARD CURVE FOR DATED BRENT ($/barrel)



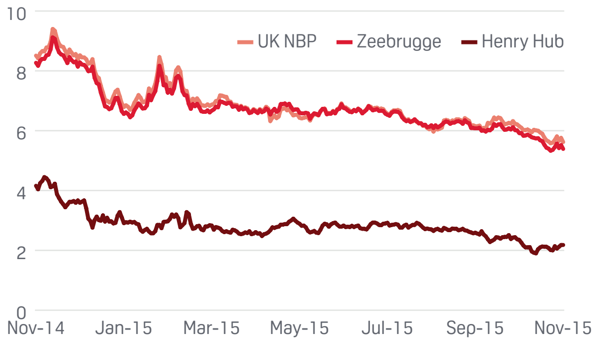
Source: Platts Forward Curve - Oil

MARKET STRUCTURE: DTD BRENT VS 1SR MO ($/barrel)



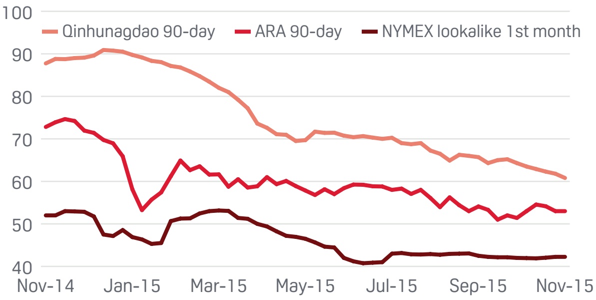
Source: Platts Global Alert

NATURAL GAS MONTH-AHEAD ($/MMBtu)



Source: Platts Gas Daily, European Gas Daily

COAL ($/mt)



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

Source: Platts Coal Trader, Coal Trader International

OIL PRODUCT COMPARISONS: NOVEMBER 20, 2015 ($/barrel)

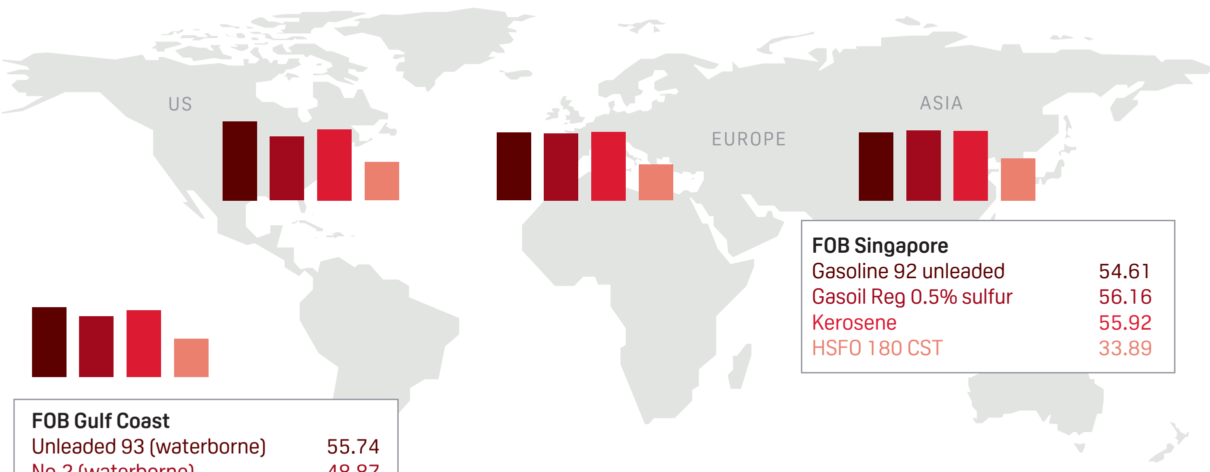
WTI Cushing Front month: 40.08

Brent front month: 43.09

Dubai front month: 39.75

CIF NY	
Unleaded 93 0.3% Barge	63.43
No.2 Barge	51.28
Jet Barge	57.16
No.6 3.0% NY Spot cargo	30.87

FOB Rotterdam Barges	
Premium Gasoline 10 ppm	54.49
Gasoil 0.1%	54.05
Jet	55.03
Fuel Oil 3.5%	28.82

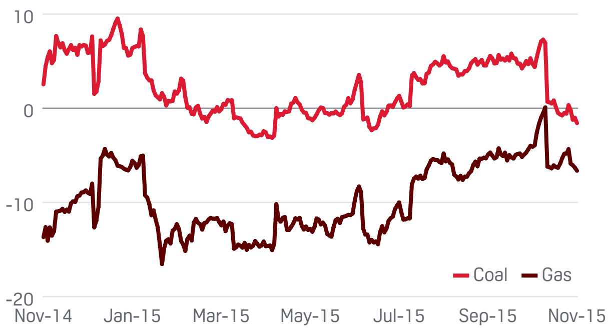


FOB Singapore	
Gasoline 92 unleaded	54.61
Gasoil Reg 0.5% sulfur	56.16
Kerosene	55.92
HSFO 180 CST	33.89

FOB Gulf Coast	
Unleaded 93 (waterborne)	55.74
No.2 (waterborne)	48.87
Jet 54 (waterborne)	53.70
No.6 3.5%	30.67

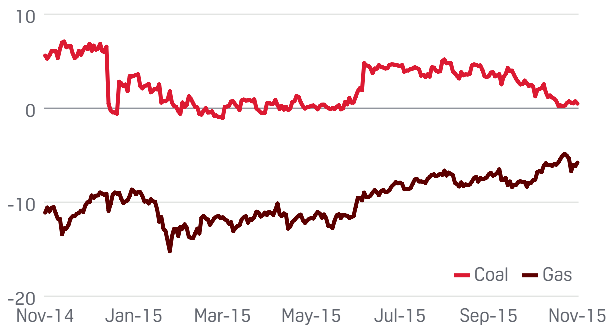
Source: Platts Global Alert

NWE NEXT MONTH GENERATING COST COMPARISONS, PROFIT/LOSS ($/MWh)



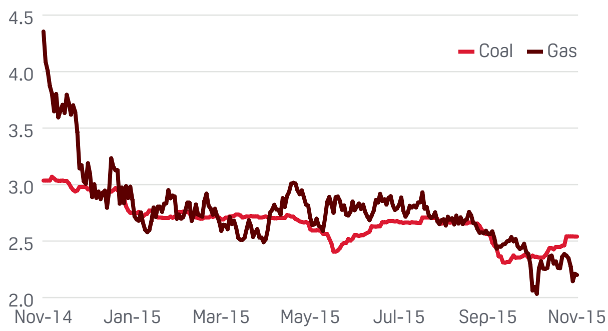
Source: Platts European Power Daily

NWE NEXT QUARTER GENERATING COST COMPARISONS, PROFIT/LOSS ($/MWh)



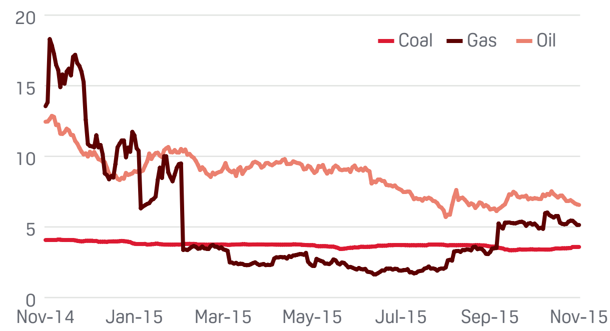
Source: Platts European Power Daily

US SOUTHEAST FUEL COST COMPARISON ($/MMBtu)



Source: Platts

US ISONE FUEL COST COMPARISON ($/MMBtu)

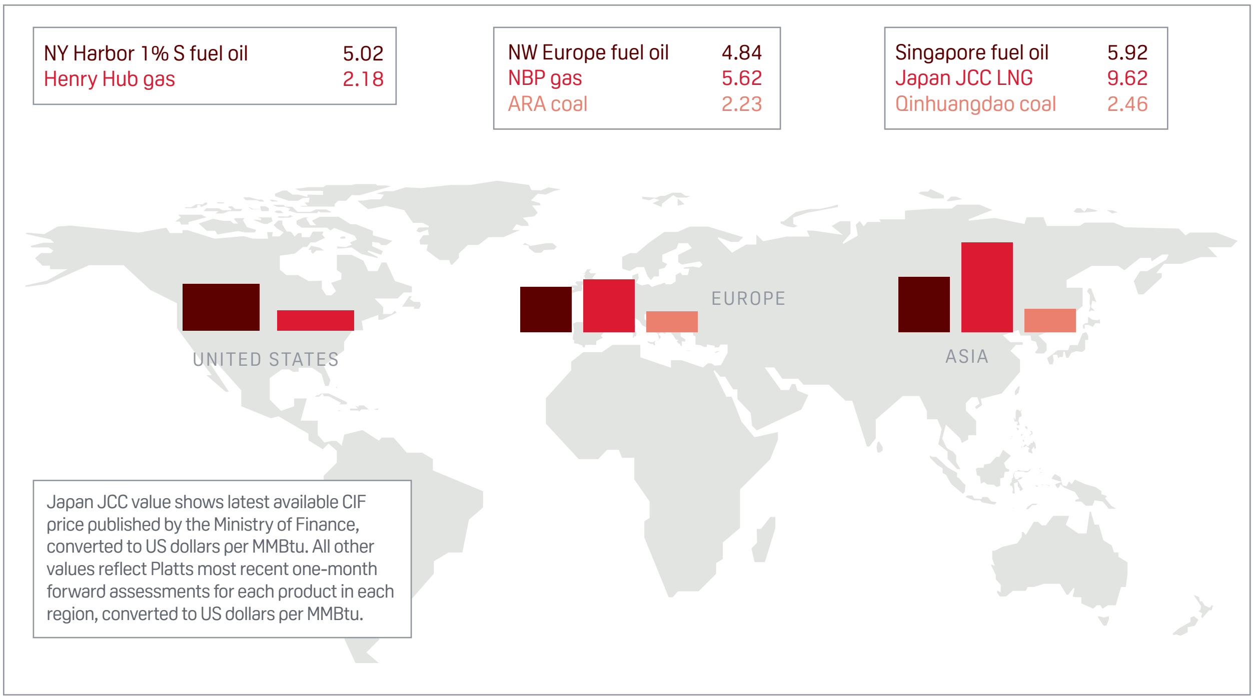


Source: Platts

NWE Note: Based on typical kg CO2/mmBtu rates of 101.5 for coal, 55 for natural gas; and on generating efficiencies of 49% for UK gas plant, 54% for western Europe gas plant, 34% for all coal plant. Benchmark coal priced at ARA. Details of methodology at www.platts.com.

US Note: Based on typical heat rates of 9,800 Btu/kWh for coal generation and 7,800 Btu/kWh for natural gas generation; no NOx controls on coal stations resulting in 0.6 lb/mmBtu NOx; benchmark coals meeting specifications for NYMEX look-alike and CSX-Big Sandy/Kanawha Central Appalachian coals, barged to Cincinnati and railed to Atlanta, respectively. For details, see methodology at platts.com.

COMPARATIVE POWER FEEDSTOCKS: NOVEMBER 20, 2015 ($/MMBtu)



Source: Platts LNG Daily

Gas markets
Platts Japan-Korea Marker, which shows the price of spot LNG in the Asia-Pacific market, rose from $7.2/MMBtu at the beginning of November to $7.65/MMBtu November 9, before falling back to $7.375/MMBtu November 24.

The price of LNG for December delivery to northeast Asia averaged $7.280/MMBtu between October 16 and November 13, a gain of 8.7% month-over-month, owing to new sources of demand emerging ahead of the northern hemisphere winter heating season. Demand remained tepid from buyers in China, South Korea, Taiwan and Japan, owing to high inventory levels, but interest was seen from India, Pakistan and the Middle East. End users in India, Pakistan and Kuwait collectively tendered and/or launched expressions of interest for an estimated 14 cargoes for December-January delivery.

Meanwhile, the price of possible competing fuels – thermal coal and fuel oil – fell. Thermal coal was lower by 3.2% on a month-on-month basis, while fuel oil was down by 0.8% month-over-month during the October 16 to November 13 assessment period.

In the US, front-month Henry Hub futures recovered initially at the start of November from lows close to $2/MMBtu at end-October, only to fall back to $2.145/MMBtu November 20. US natural gas in storage increased 15 Bcf to 4.0 Tcf in the week ended November 13, according to EIA data. The net injection was below consensus expectations of an injection of 17-21 Bcf.

In the corresponding week last year the EIA reported a 9 Bcf withdrawal, while the five-year average is a 12 Bcf withdrawal. As a result, stocks were 404 Bcf higher than this time last year and 207 Bcf above the five-year average of 3.793 Tcf. Although the US is experiencing below average temperatures, boosting heating demand, weather forecasts at end-November appeared to be moderating.

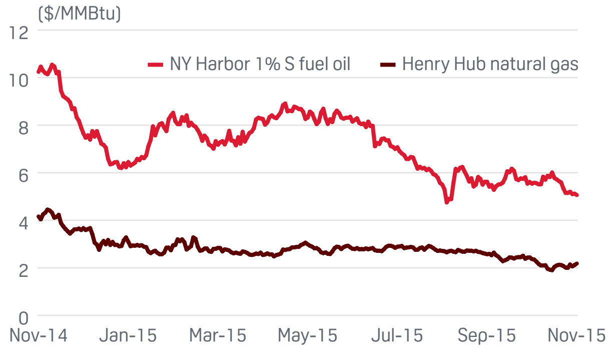
In Europe, UK NBP day-ahead prices traded at five-year lows during the two-week period to November 11 as mild weather allied to robust LNG supply reinforced bearish sentiment in the UK gas market. The day-ahead contract was assessed at 33.55 pence/therm November 11, its lowest assessment since September 2010.

Prices on the Belgian Zeebrugge hub fell steadily in the period because of mild temperatures, healthy supply and weak oil markets. Gas for day-ahead delivery started the month at 36.65 p/th, but had fallen to 33.90 p/th by November 11.

Coal markets
South African FOB Richards Bay 6,000 kcal/kg NAR spot thermal coal prices rose over $9/mt during November following a resurgence of spot demand and limited availability. Platts assessed FOB Richards Bay 6,000 kcal/kg NAR at $57.95/mt November 20, $9.20 higher month-on-month. South African 6,000 kcal/kg NAR coal was scarce as miners have maximized production of lower calorific value coals in order to appeal to buyers in Asia-Pacific.

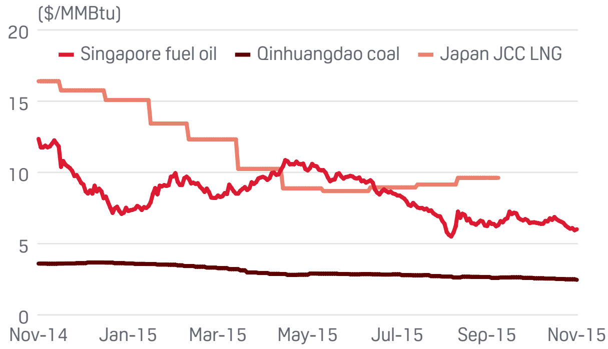
However, market participants pointed to a large producer/trader driving prices higher, as some had offered cargoes at lower price levels without identifying any demand. Higher South African coal prices also hindered the return of Indian buyers to the market.

COMPARATIVE POWER FEEDSTOCK PRICES: US



Values reflect Platts most recent one-month forward assessments for each product in each region, converted to $/MMBtu.
Source: Platts LNG Daily

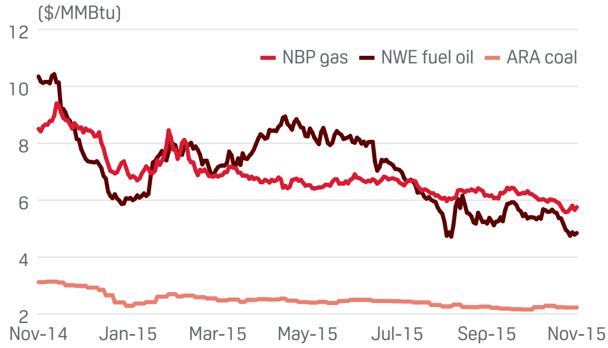
COMPARATIVE POWER FEEDSTOCK PRICES: ASIA



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

Source: Platts LNG Daily

COMPARATIVE POWER FEEDSTOCK PRICES: NWE

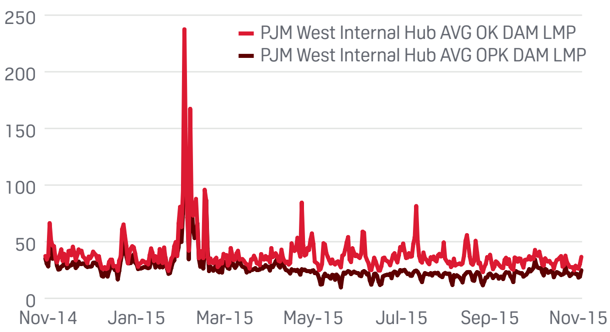


Values reflect Platts most recent one-month forward assessments for each product in each region, converted to $/MMBtu.
Source: Platts LNG Daily

UK BASELOAD MONTH AHEAD (£/MWh)

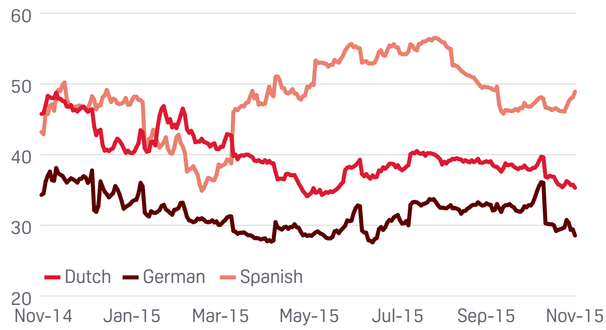
Source: Platts European Power Alert

PJM WEST AVG OK/OPK DAM LMP ($/MWh)



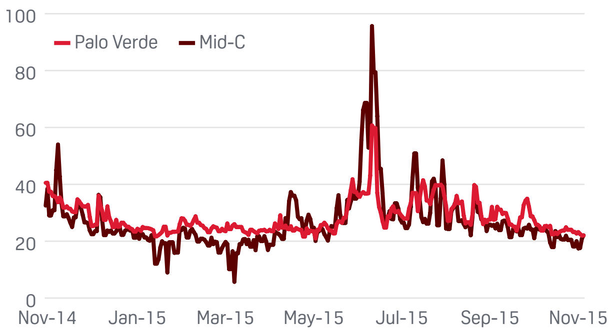
Source: Platts

EUROPEAN BASELOAD MONTH AHEAD (€/MWh)



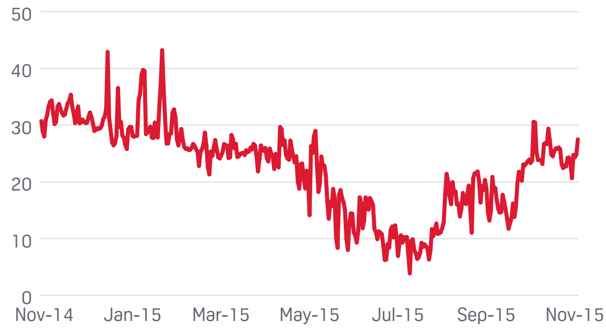
Source: Platts European Power Alert

US DAY AHEAD ($/MWh)



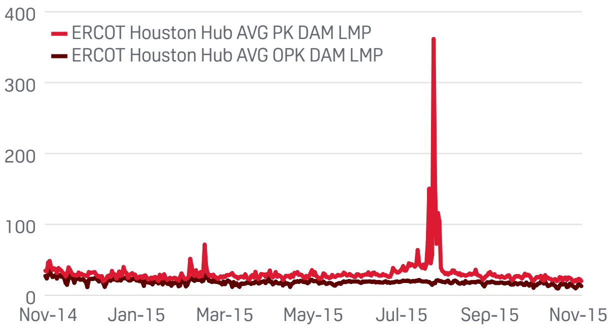
Source: Platts

NORD POOL SYSTEM DAY AHEAD (€/MWh)



Source: Platts European Power Alert

ERCOT (HOUSTON) AVG PK/OPK DAM LMP ($/MWh)



Source: Platts

In Europe, the CIF ARA thermal coal market remained buttressed by continued spot utility buying and a reduced number of 6,000 kcal/kg NAR cargoes on offer in the brokered market. Platts assessed CIF ARA 6,000 kcal/kg NAR prices at $54.50/mt November 20, up $1.25 month-on-month.

Germany has experienced higher coal burn in recent months following lower hydro levels and weaker wind generation. This coincided with low Rhine river levels, which made it difficult and expensive to barge coal from ARA ports to inland power stations. Market sources said this made German utilities more reluctant to sell cargoes, particularly so close to the winter season, and allowed those players who needed to cover short positions to bid the spot CIF ARA market higher.

In the Asia-Pacific market, price dynamics for seaborne thermal coal trading into China remained bearish, with domestic Chinese miners lowering their offers further in order to compete with imported material. In late November, Shenhua Group lowered the selling price for its 5,500 kcal/kg NAR domestic thermal coal with less than 0.8% sulfur to Yuan 368/mt FOB Huanghua port, down Yuan 6 from Yuan 374/mt FOB, the price it had originally set for November shipments. Platts assessed the Australian Newcastle 5,500 kcal/kg NAR with 20% ash content at $38/mt November 20, down $4.15 on the month.