

Energy Economist

New world, old thinking . . . 3

Having survived one oil price spike, another looms. Insufficient investment, a forecast resumption in oil demand and rapid depletion point to a new supply crunch. Oil futures have risen, despite a surfeit of crude and shrinking consumption. But is this exuberance rational? The high-price paradigm that has governed commodity markets since 2002 has risen from the ashes of recession and been uncritically reinstated. **Ross McCracken**

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The disputed re-election of President Mahmoud Ahmadinejad has revealed deep splits in Iranian society bringing into question the country's political stability. Suppression of the protests is likely, but Ahmadinejad will still have to address Iran's ailing oil and gas sector. Starved of capital and technology, the industry looks incapable of increasing capacity, addressing its gasoline deficit, or monetizing its huge gas reserves.

Ukraine struggles to meet Russian cash call 11

The threat of a disruption to European gas supplies has become a monthly event on the gas market calendar as Ukraine's Naftogaz struggles to pay its Russian task master Gazprom. A new agreement on gas transit is needed. Perversely, if a stable framework governing the gas flow through Ukraine could be agreed, Europe might conclude that it has less to fear from greater dependence on Russian gas. **Paul Whitehead, Alex Bor**

LNG market hit by US gas glut 15

From supply crunch to supply surplus, the US unconventional gas boom has worldwide implications for the LNG market. With the US a market of last resort, and demand growth from non-OECD Asia constrained by a lack of infrastructure, Europe will play the pivotal role in determining future LNG demand. This pits pipelines against LNG vessels and will test gas producers' ability to manage supply. **Ross McCracken**

SMEs face further borrowing pressure 19

Small and medium-sized energy companies' ability to raise capital is shrinking as banks consolidate their lending on established customers with large asset bases. SMEs can turn to mezzanine financiers, but even here the number of lenders has contracted, and the cost of borrowing has risen. This is placing a large constraint on a traditionally dynamic sector that plays a key role in the US energy sector's fortunes. **Jayne Jung**

Bolivia – missing the natural gas boat 22

Bolivia's government needs foreign investors to expand its output of natural gas. Business plans that promise new investment have gradually emerged under the nationalized regime, but the country has already lost future market share in the region to LNG. Moreover, neither the capital nor trust exists to build a new pipeline to Argentina, which would ensure a market for expanding Bolivian gas exports. **Charles Newbery**

Sub-Saharan Africa: three in four lack power 25

The failure to provide electricity in sub-Saharan Africa reflects not just a lack of generating capacity, but a lack of transmission and distribution infrastructure. However, some countries with the right combination of political will, socio-economic goals and donor support are recording successes, while distributed power systems may provide a means around the inability to invest in delivery infrastructure. **Neil Ford**

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China's Copenhagen carrot

Reports that China may raise its target for renewable energy to 20% of total energy consumption by 2020 will no doubt be welcomed, but the ability to set targets and the capacity meet them are two different things. In the run-up to the COP 15 UN Climate Change conference in Copenhagen in December, China wants to signal that it can control its greenhouse gas emissions without committing to a clear cap. The more ambitious its renewables targets, the more persuasive its argument.

China's installed generating capacity is expected to be 860 GW by end-2009, while its consumption of crude oil is currently about 7.9 million b/d. Even at today's levels a 20% target would mean the construction of 172 GW of renewable energy and the development of 1.58 million b/d of biofuels. This is, of course, a gross underestimate because it assumes zero growth. Even in the current economic downturn, Chinese power demand is growing by about 5% a year.

Moreover, the proportion of capacity made up by renewables underestimates their contribution to power supply, owing to low capacity factors. And China's agricultural policies are geared towards food security not biofuels, while its oil import substitution strategy is based on coal-to-liquids. As in the OECD, and perhaps more so, the Chinese biofuel sector can be expected to underperform, putting more of the burden for meeting a 20% mandate on the power sector. A more likely target for renewables would be one third of installed capacity.

This is not to deride the efforts China is making in its pursuit of renewable energy. Nor its ability to invest on a huge scale. The Chinese wind sector in particular is booming and the government is backing its policies with large amounts of real money. But even the official target of 15% by 2020 is a gargantuan task. The 20% target is no more than a bargaining chip, and it represents an IOU rather than real currency.

– **Ross McCracken@platts.com**

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New world, old thinking . . .

Having survived one oil price spike, another looms. Insufficient investment, a forecast resumption in oil demand and rapid depletion point to a new supply crunch. Oil futures have risen, despite a surfeit of crude and shrinking consumption. But is this exuberance rational? The high-price paradigm that has governed commodity markets since 2002 has risen from the ashes of recession and been uncritically reinstated. **Ross McCracken**

The short-term fundamentals of the oil market look exceptionally weak, yet the oil price has risen from lows in February of just below \$40/barrel to break back above \$60/b and then above \$70/b. Given no shortage of crude, and further downgrades to consumption, the cause is thought to be flows of capital into commodity markets based on the assumption that oil is, or at least was, undervalued.

With the futures market in contango – prices for future delivery dates are higher than for early delivery dates – there is a cost to holding a long position. The contango exists because of the surfeit of crude available for immediate or near-term delivery, which pushes prices down at the front end of the forward curve.

Holders of long positions have to roll their positions forward each month and in a contango the next month will be more expensive than the front month. So each roll costs money. As a result, investors putting capital into the market must have good reasons to believe that the oil price will continue to rise. It must, if they are to be more than compensated for the cost of the contango.

In effect, the high-price paradigm that governed the commodity boom of the 2000s has shaken itself down and re-emerged apparently unscathed from the financial crisis and ensuing global economic downturn. The question is – does it deserve uncritical reinstatement? But, first, why is oil perceived to be undervalued?

Insufficient investment

The argument that investment in the oil industry is insufficient to meet future demand predates the economic downturn. However, it has taken on new relevance with the drop in oil price from last August to February this year. Lower oil prices have seen a retrenchment in investment. Investors have also suffered from the inability to tap cheap capital. Highly-leveraged smaller oil companies have been particularly hard hit, seeing revenue fall on the one hand and the cost of capital rise on the other.

The International Energy Agency never misses an opportunity to sound the alarm bells with regard to investment and in a report prepared for the G8 energy ministers meeting in Rome in late May, the IEA said it saw “clear evidence” that energy investment across the world would drop sharply this year, with global upstream oil and gas investment budgets already cut by around 21% or almost \$100 billion from 2008 levels.

“Between October 2008 and end-April 2009, over 20 planned large-scale upstream oil and gas projects, valued at a total of more than \$170 billion and involving around 2 million b/d of oil production capacity and 1 Bcfd of gas capacity, were deferred indefinitely or cancelled,” it said. A further 35 projects, involving 4.2 million b/d of oil capacity and 2.3 Bcfd of gas capacity, had been delayed by at least 18 months, the agency claimed.

But the underlying argument is rooted not so much in the current downturn as in the willingness and ability of International and National Oil Companies to invest even when they have the money. In a recently updated report, Paul Stevens, Senior Research Fellow for the Energy, Environment and Development Program for UK think-tank Chatham House, notes that in 2005, the six largest IOCs invested \$54 billion, but returned to their shareholders \$71 billion. IOCs have been following a financial strategy based on ‘value-based management’, which suggests excess funds should be returned to shareholders rather than invested.

In turn, he argues, NOCs are pursuing strategies based on maximizing recovery and optimizing resources, which is producing a tendency to see the best rate of return long-term coming from leaving oil in the ground rather than investing in new production capacity. Added to this are management and supply-side limitations that have undermined IOC and NOCs’ ability to invest and undertake multiple large projects, while IOCs are also limited by their lack of access to resources.

That investment is insufficient is certainly the message of industry leaders. BP CEO Tony Hayward warned in June that crude prices could reach \$150/barrel “in the next decade” if there is not sufficient investment in future supplies. Hayward said that while demand in OECD countries was balanced, demand from the non-OECD will continue to increase. He urged the industry to keep investing through the economic downturn. The head of Russian gas giant Gazprom said the oil price could surpass \$250/barrel in coming years because of a lack of investment in new production capacity. Speaking in Porto Cervo, Italy, Alexei Miller said, “nobody has solved the issue of the 2012 supply gap . . . It may emerge somewhat later, but it will be deeper.”

Demand growth resumes

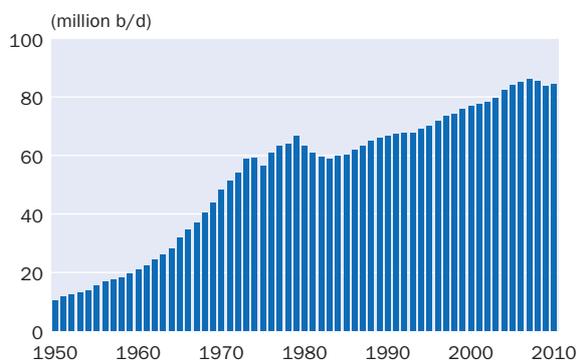
A return to demand growth is the second assumption of the supply crunch argument. Once the world economy has recovered from the current downturn – the bottom of

the cycle is generally predicted in the third quarter – business will return to ‘normal’, and for the oil market this means a return to oil demand growth. Despite this year’s slump, the US Energy Information Administration predicts that world oil demand will grow by 0.7 million b/d in 2010, driven by a rebound in the world economy and reinvigorated oil demand growth in the Middle East, China and India.

On this basis, the current recession would have resulted in a much smaller reduction in oil demand than that seen in the wake of the 1970s oil supply crises. Demand fell then by 4.3 million b/d between the peak in 1980 and the trough in 1983, a drop of 6.9%. On the EIA’s figures, the current recession will result in a demand drop of 2.2 million b/d between the 2007 peak and a trough in 2009, a decline of only 2.7%.

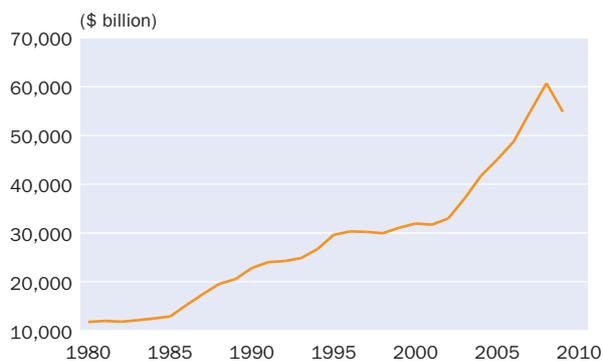
The underlying argument is well known. China and India in particular have seen per capita income rise for substantial portions of their huge populations to a level where first time car ownership has become possible. In addition, these economies have not contracted in the current downturn, even if growth rates have been seriously curtailed. As growth picks up, steady increases in car, rail and air transport are expected, while industrial expansion will return to former high rates of growth. At

World oil consumption



Source: IMF, EIA, various

World GDP growth (current prices)



Source: IMF, EIA, various

its simplest, the argument is that car ownership levels, and oil use more generally, will rise gradually towards European and US levels, causing a sustained and large rise in oil demand.

Depletion rates rise

The third premise is that as the volume of oil produced expands an increasing amount of new production is taken up replacing depletion from old oil fields rather than adding to total output. The IEA carried out a field-by-field analysis of depletion rates in its 2008 World Energy Outlook and concluded that “future supply is far more sensitive to decline rates than to the rate of growth in oil demand.”

The IEA noted that as field size declines, depletion rates rise. In addition, offshore fields decline quicker than onshore ones, and deepwater fields quickest of all, owing to the way in which they are exploited. As such, the trend, particularly evident in the OECD, towards smaller and offshore fields, suggests that the average decline rate will increase over time.

The IEA looked at 580 of the world’s largest fields that have passed their production peak and calculated that the average observed post-plateau decline rate was 5.1%. Adjusting for the fact that the fields studied were much larger than the average field size, the IEA estimated that the average production-weighted observed decline rate worldwide was 6.7% for post-peak fields, equal to 4.7 million b/d based on 2007 output.

New price spike

Brought together, the oil market faces supply being undercut by depletion and insufficient investment, while at the same time having to meet new growth in oil demand. In the words of the IEA, “there is a real danger that sustained lower investment in supply in the coming months and years could lead to a shortage of capacity and another spike in energy prices in several years time. The faster the recovery, the more likely that such a scenario will happen.”

According to Stevens, “unless there is a collapse in oil demand within the next five to ten years, there will be a serious oil ‘supply crunch’ – not because of below-ground resource constraints but because of inadequate investment by IOCs and NOCs. An oil supply crunch is where excess crude producing capacity falls to low levels and is followed by a crude ‘outage’ leading to a price spike.”

New paradigm

There is no doubt that these arguments are formidable, but there are countervailing trends to which timing may be the key. Oil demand does not have to grow inexorably. In the wake of the oil price spikes of the 1970s, European oil demand fell from 16.05 million b/d in 1980 to 13.78 million b/d in 1985, but took 13 years until 1998 to return to the 1980 level. It reached

16.44 million b/d in 2006 before high prices again put it on a downward path. The 2008/09 economic slump will set it back yet further.

A substantial part of the reason was the decline in use of oil for power generation that cannot be repeated, but it also reflected trends in transportation and greater energy efficiency. The reduction in recent years reflected a response to high oil prices before the current recession took hold. Notably, the strong growth in the number of cars per person in Europe since 1980 does not correlate linearly with oil demand growth.

Japan is another case in point. Admittedly a period characterized by low economic growth, Japanese oil demand peaked in 1999 at 5.6 million b/d, falling to 5.0 million b/d in 2007 before the onset of the economic slowdown brought it in 2008 down to a level below that last seen in 1988. Again, while oil demand was falling from 1999, per capita car ownership was rising, from 404 per thousand people in 1999 to 441 per thousand in 2004.

In addition, current economic revival policies are being heavily influenced by security of supply and climate change concerns. The factors governing car use in the US are different to those in Europe and Japan, but Washington's first-ever greenhouse gas tailpipe standards announced in May in conjunction with tougher auto fuel economy standards may prove a major turning point – one that builds on the impact in recent years of the highest pump prices US consumers have ever seen.

China and India are both different again and the size of their populations alone is argument enough that increasing car ownership will see steady increases in oil use. However, the size of population, road infrastructure and city design may prove constraints in themselves, as may local pollution issues. The link between car ownership and oil use is far from linear and it may be wrong to assume that developing countries will follow a similar path to Europe and the US in terms of oil use.

Investment and decline rates

If low prices stall investment, then high prices encourage it. The companies that benefited most in the recent run-up in oil prices were those that invested in the period immediately beforehand when the oil price was at its lowest. US oil major ExxonMobil for one says that its policy is to spend through the investment cycle and recent events should serve to reinforce the wisdom of that policy amongst other majors, particularly if the expectation is of higher prices in the future.

Moreover, investment cutbacks reflect not lower oil prices alone but the huge rise in Engineering, Procurement and Construction costs that accompanied the run-up in the oil price. EPC costs have been slower to soften, but are now falling. With the oil price reviving, the differential between the two has improved. Some analysts have argued that investment

Rising commodity prices pose threat to recovery

Recent flows of investment money into commodities reflect a desire to hedge against inflation. The huge amounts of liquidity being injected into the economy through the monetization of government debt has naturally raised concerns that inflation will start to rise. Central bank policy is firmly bent on maintaining low interest rates for a sustained period as rises in interest rates would be seen as a premature stifling of recovery. There is also the suspicion that central banks will tolerate higher levels of inflation precisely to inflate governments out of the huge debt hole they have created.

Furthermore, there is the perception that inflation will be manifest in commodity markets first, rather than through the more traditional push of wage-driven inflation. This fits neatly with the view that a new oil price spike is looming. The bottleneck in the economy is oil and other commodities rather than a lack of spare industrial capacity. So diversifying financial portfolios away from equities and bonds, which might suffer from inflation, to commodities, where prices will benefit, makes sense.

This raises the question of what impact the rise in commodity prices will have on the recovery itself. Rather than being strangled by tough monetary policy instituted by central banks keen to stamp out expectations of rising prices, higher commodity prices could do the job instead. Airlines are a case in point. Having seen demand wither with the impact of economic contraction on incomes, the airline industry is seeing its cost base rise ahead of any real recovery in demand for its product.

The rise in oil prices up to 2008 was notable for its lack of impact on the real economy. Theories had to change rapidly and it was determined that spending on oil for consumers represented a much smaller part of their disposable income. Increases in price could thus be more easily absorbed without changing consumer behavior. In addition, incomes were rising anyway, reflecting robust world growth, and the emergence of China as the world's manufacturing workshop created a powerful countervailing disinflationary force.

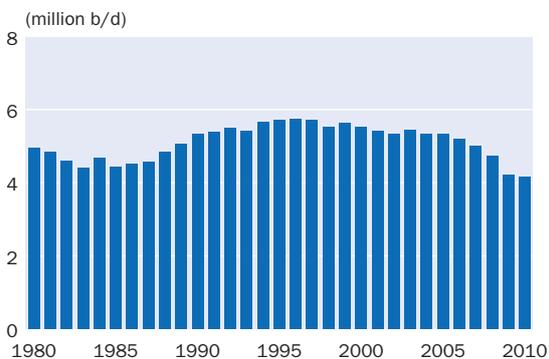
But are these arguments still valid? With incomes stagnant and unemployment rising, higher oil prices should have more of an impact on consumer behavior. The wealth effect has dissipated and the disinflationary trend in manufacturing has run its course. Higher oil prices cannot be absorbed without robust economic growth. In short, the perception of a looming oil supply crunch will, through higher oil prices, retard the recovery and the very resumption in demand growth on which it is based.

stalled not because oil prices fell, but because EPC costs didn't. With oil prices higher on the back of the 'impending oil supply crunch', investment can be expected to pick up in 2010.

The IEA's argument that cuts in spending on existing fields risk pushing up decline rates can also be challenged. In the US gas industry production has not fallen in line with the sharp fall in the rig count. One of the reasons is that while companies do cut back on new exploration they tend to focus instead on getting more out of their producing assets, which they need to keep running to maintain revenue, even if prices are lower. More gas is likely to be recovered from the same asset as a result, reducing decline rates. The same is true of oil. In addition, decline rates have to be set against enhanced recovery technologies, which have raised the amount of recoverable oil from existing reserves.

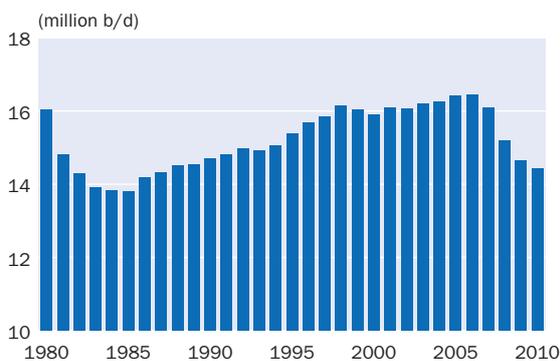
The IEA tends to overstate its case in order to drive home its policy message. Notably the focus on the decline rate of post-peak fields provides the figure of 4.7 million b/d based on 2007 output. While this illustrates the scale of the problem, it is not an expression of a real fall in total output. The IEA's prediction for growth in non-OPEC supply in 2009, for example, is for a contraction of just 0.1 million b/d.

Japanese oil consumption



Source: EIA

European oil consumption



Source: EIA

Nevertheless, decline rates, investment levels and a lack of access to resources are undoubtedly problems. The single most dramatic example that encapsulates all three is the sharp fall in output from Mexico's Cantarell field, which is accompanied by a political deadlock over meaningful energy sector reform. This is denying the state oil company PEMEX access to the foreign technology it needs to invest in the country's offshore resources, while at the same time denying IOCs access to substantial reserves. More broadly, there has been no evidence that reduced oil prices have started to reverse the trend towards resource nationalism.

Counter theory

The current slump has increased the margin of spare capacity, while investment in new oil fields in Saudi Arabia has boosted it further. The EIA estimates that OPEC's surplus capacity this year will amount to 4.51 million b/d, rising to 5.17 billion b/d in 2010, the highest level since 2002, which itself represented a peak.

This is a substantial cushion, one that will prove all the greater if projections of renewed demand growth do not materialize. OPEC's control of this surplus also increases the likelihood of higher prices in the short to medium term irrespective of the evolution of demand, supporting investment.

As such, an alternative to the oil supply crunch hypothesis runs as follows: declines in OECD oil demand continue and offset lower-than-expected growth in the non-OECD. The world economy does not return to the robust levels of growth seen before the financial crisis, but instead experiences positive but low GDP growth. Climate change and security of supply policies gather pace, both in the OECD and developing countries, raising the contribution to oil supply of oil import substitutes and increasing the efficient use of energy, particularly in the transport sector.

This provides time for alternatives to oil to enter the transportation market and sustain a long-term downward trend in OECD oil demand. A large margin of surplus capacity and an oil price well above what might be expected based on demand alone is sustained, first, by the perception that an oil supply crisis is pending and, second, by OPEC output restrictions. Notably, the evolution of world oil consumption shows a sharp gradient until the supply crises of the 1970s. Once oil demand growth resumed, the gradient was substantially reduced. It may now flatten further.

The central proposition is not just that the financial crisis and ensuing recession have changed the landscape, but that the policies resulting from security of supply and climate change concerns that predated the recession have gained momentum and traction because of the recession. First from the focus on the 'green economy' as a core element of counter recessionary spending and, second, from the breathing space provided by the current slump in oil demand.

Iran on the brink

The disputed re-election of President Mahmoud Ahmadinejad has revealed deep splits in Iranian society bringing into question the country's political stability. Suppression of the protests is likely, but Ahmadinejad will still have to address Iran's ailing oil and gas sector. Starved of capital and technology, the industry looks incapable of increasing capacity, addressing its gasoline deficit, or monetizing its huge gas reserves.

The demonstrations that erupted in Iran following the disputed re-election of Iranian President Mahmoud Ahmadinejad on June 12 have revealed deep-seated social tensions and popular discontent in one of the world's leading crude exporting countries. Iran also holds the world's second largest natural gas reserves.

The country has seen almost daily protests since the election, as well as the mobilization of pro-government supporters. Hundreds of riot police armed with steel clubs and firing tear gas put down an opposition rally in the capital on June 22 after the country's Revolutionary Guards warned it would crush further protests.

The prolonged demonstrations mark the worst crisis in Iran since the revolution of 1979. Foreign media have been restricted in their reporting, but images of police brutality have spread worldwide via the Internet. According to state media, at least 17 people have been killed and many more wounded. Hundreds of protestors and prominent reformists and journalists have been rounded up, even those close to top regime figures.

In an attempt to undermine the legitimacy of the protests, Iran has blamed outside forces, particularly the UK and US, for instigating unrest. The EU has rejected Iran's claims of interference as "baseless and unacceptable" and expressed deep concern about the continuing brutality. However, the dispute is not between pro and anti-Western factions, but between the Islamist and republican traditions of the 1979 revolution.

Defeated rival Mirhossein Mousavi, a former prime minister and respected moderate, has led the protests over what he says was a rigged election. He has urged supporters to continue demonstrating, but to adopt "self-restraint" to avoid more bloodshed. Although the government appears to have quieted the protests for the moment, and one defeated presidential candidate, Mohsen Rezai, a conservative, has withdrawn his complaint about the poll, the opposition remains defiant. Defeated reformist candidate Mehdi Karroubi has called for a ceremony on June 25 to mourn slain protestors.

The election watchdog, the Guardians Council, has acknowledged some discrepancies in the June 12 vote, but council spokesman Abbasali Kadkhodai has been quoted as saying, "In the recent presidential election we witnessed no major fraud or breach. Therefore, there is no possibility of an annulment taking place." The opposition has registered 646 election irregularities and wants not a recount but a new vote.

The state of the economy, which many of Ahmadinejad's detractors say has worsened because of his high-spending inflationary policies and free use of surplus oil funds to finance these policies, played large in the election. His 2005 campaign pledge to put oil money on people's tables may have served Ahmadinejad well in rural areas, his main support base, but not in urban centers, where he has become deeply unpopular.

Not only does Ahmadinejad now face a challenge to his position, sharpened by the election's perceived lack of legitimacy, but deep economic problems, the heart of which lie in the country's failing oil and gas industry. Promises of investment have not borne fruit and the country's production capacity is struggling with low recovery factors, high decline rates, and the need to source gas for reinjection, while Iran's chronic gasoline deficit continues to erode the state's finances.

Extravagant claims

Oil minister Gholamhossein Nozari, who was hand-picked for the job by Ahmadinejad in 2007, announced many new deals in the run-up to the election, in what was seen as attempt to bolster Ahmadinejad's standing. Nozari awarded contracts for several phases of the giant South Pars gas field and signed a contract with the China National Petroleum Corporation worth almost \$5 billion. On June 8, just days before the election, he announced the launch of the world's biggest enhanced oil recovery project at the mature Aghajari oil field.

Even more significant was an announcement by Nozari that two Western oil majors, Anglo-Dutch major Shell and Spain's Repsol, had resubmitted bids for development of South Pars phases 13 and 14, also known as Persian LNG. But the report was not confirmed by either of the two foreign companies and analysts believe it was yet another attempt to burnish Ahmadinejad's image.

The announcement of major new deals has not stopped. Speaking in Moscow, Iran's deputy oil minister Seyed Shahnazizadeh announced June 23 plans to build a new 1 million b/d pipeline to transport crude from the Caspian Sea to the Persian Gulf. Iranian National Oil Company manager Bahan Sorooshi said more than 20 fields will be developed as part of the next five-year development plan. "We are going to offer some of these fields to foreign contractors," he added.

According to Sorooshi, Iran also plans to commission phase 7 of the giant South Pars gas field development in September, targeting production of 25-26 MMcmd of

natural gas. He said that phases 6 and 8 had been commissioned and the three phases would be completed by the end of summer. The signing of a preliminary agreement with a group of Turkish companies, led by state-owned upstream operator TPAO, for the development of phases 22, 23 and 25 of South Pars was also revealed.

However, Iran still faces international sanctions, owing to its nuclear program, limited domestic ability to carry out the projects it is announcing, and there is no indication that the terms it is willing to offer foreign investors have improved. Moreover, many of Ahmadinejad's claims are disputed by senior Iranian oil officials. Indeed, deputy oil minister Akbar Torkan told a recent investment conference in Tehran that foreign companies were invited to participate in South Pars phases 11, 13 and 14 precisely because Shell and Repsol were no longer involved. Torkan was sacked on June 23.

Ahmadinejad has also claimed credit for several oil, gas and petrochemicals projects he said were completed during his first term. He said that his administration had brought on line five phases of South Pars (phases 6-10),

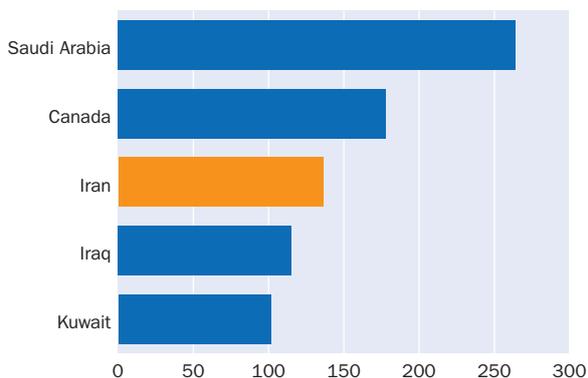
gas processing plants and petrochemicals plants in addition to raising production capacity. Sorooshi's comments in Moscow clearly show that South Pars phases 6,7 and 9 have not been completed.

Former oil minister Bijan Zanganeh wrote to Ahmadinejad informing him that the projects he referred to were started during the presidency of Mahmoud Khatami and were 60% complete when Ahmadinejad took over in 2005, noting that they remain unfinished, including South Pars phases 6-10 and phase 2, which Zanganeh said was almost complete when Ahmadinejad came to power. Phases 9 and 10 were also awarded to a consortium by the Khatami government.

Furthermore, no petrochemicals projects have been launched by Ahmadinejad's government, with the exception of the Kavian project, Zanganeh wrote in his detailed letter. All other petrochemicals projects that are coming on line now were awarded and implemented by the previous government, he added.

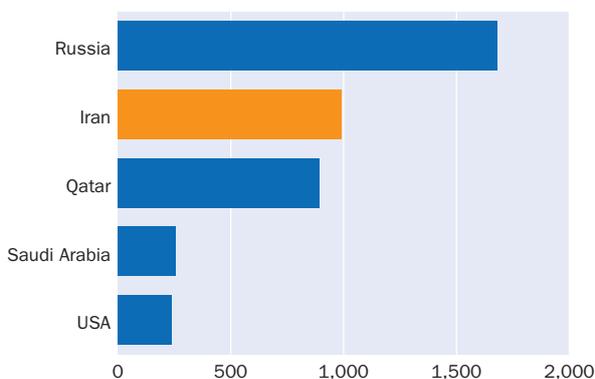
The former oil minister insisted that after four years of Ahmadinejad's policies, Iranian oil production capacity was still 3.90 million b/d and not the 4.35 million b/d claimed by Ahmadinejad's ministers, an allegation that has been repeated by other senior serving oil officials.

Top proven oil reserves (billion barrels)



Source: Oil & Gas Journal, Jan 1, 2009

Top proven gas reserves (Tcf)



Source: Oil & Gas Journal, Jan 1, 2009

Real and imagined capacity

Analysts doubt that Iran is capable of sustaining oil output much above 4 million b/d given its low recovery rates and steep declines from mature fields. Production capacity has stagnated in recent years. The reluctance by Western oil and gas companies to enter Iran has led Tehran to turn increasingly to companies from China and other Asian countries for help in developing the remaining phases of South Pars and huge undeveloped oil fields such as Azadegan and Yadavaran. Yet real investment from these sources has so far been limited.

It is difficult to determine exact figures for oil, gas and petrochemicals production in Iran or the volume of output increases last year. NIOC officials time and again provide conflicting figures in their public statements and tend to refer to figures to be realized in the future.

The National Iranian South Oil Co. says it raised production in 2008 by 328,000 b/d, while the natural decline rate was 340,000 b/d. Total onshore output by NISOC last year was 3.2 million b/d. In 2009, according to NIOC officials, some 180,000 b/d of oil output capacity was expected from Azadegan (50,000 b/d), Khesht (30,000 b/d), Hengam (shared with Oman, 15,000 b/d), Darkhovein second phase (60,000 b/d) and Yadavaran (25,000 b/d). NIOC CEO Seifollah Jashnsaz said March 11 that oil output capacity would rise to more than 4.3 million b/d by mid-2009.

Average offshore oil output in 2008 was 707,000 b/d and is scheduled to rise to 726,000 b/d in 2009, officials have said. The Iran Offshore Oil Company has a

long-term plan to raise offshore production to 1 million b/d. But IOOC director Mahmoud Zirakchian said in May that the company's budget had been reduced to \$400 million in 2009 from last year's \$1.4 billion. One project, the 60,000 b/d Bahrengansar offshore oil platform rehabilitation, is 16 years behind schedule.

The absence of foreign help and the limitations of local capabilities, financing, project management skills and the lack of access to new technologies, has forced NIOC to develop fields itself using "early production" schemes. Experts say this method is time-consuming, costly, and a suboptimal way of developing fields. Iran's average recovery rate is thought to be just 27%.

Early production was the method followed at Azadegan, where NIOC unit Petroliran is undertaking the first-phase development after Japan's Inpex pulled. The field, which contains 26 billion barrels of proven crude reserves, is one of the biggest discovered but not yet fully developed oil fields. NIOC has said it intended to raise production from Azadegan to 50,000 b/d by April 2009, but that target was missed and the field is believed to be producing 20,000-25,000 b/d. NIOC has struggled to develop the geologically complex giant onshore field. There has been talk of the company ceding 70% of its share to foreign companies, possibly Indian or Chinese, due to financing difficulties.

Iran plans to expand overall production capacity by 1.1 million b/d by 2017, according to the Petroleum Engineering Development Co., Pedec, which is in charge of managing implementation of NIOC's major oil and gas projects. The Azar oil field drilling program was reported to have started in April by NIOC after foreign firms such as Statoil withdrew as a result of US pressure. But there are few other major developments being launched this year, which, despite the June 23 announcements, suggests the target date will be missed.

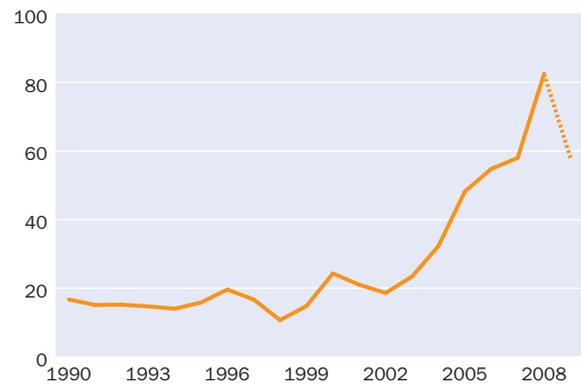
Gas limitations

A major focus is to produce enough gas to support Iran's gas re-injection program in order to sustain crude production capacity. In 2009, Pedec is due to complete the Aghajari gas injection scheme, the second phase development of the Darkhovain field (60,000 b/d), the Darkhovain gas re-injection project and the Salman and Mansuri field developments. But how much progress is being made on these projects is uncertain.

The National Iranian Gas Company said it was able to raise gas output last winter to a peak of 530 MMcmd mostly from central regions and South Pars phases 6-8 and 9-10. But the exact estimate of the increase is hard to pin down with officials giving varying figures.

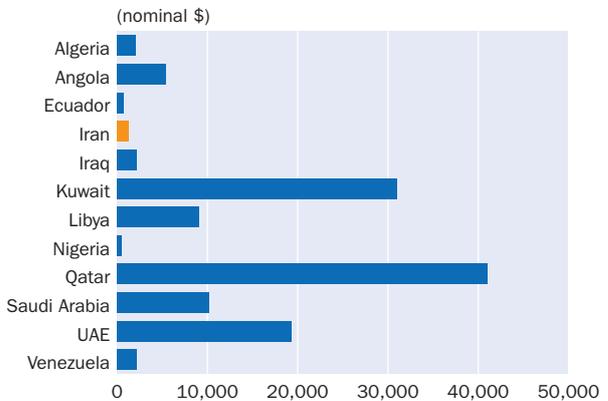
There has been some uneven progress made in developing phases 11, 12, 13, 14, 15-16 and 17-18 of South Pars by Iranian companies as foreign companies such as Total, Shell and Repsol have failed to commit to projects. Total has been negotiating for phase 11 of

Iran net oil export revenues (\$ billion)



Source: EIA

OPEC per capita net oil export revenues



Source: EIA

South Pars, but its upstream role will now be taken over by CNPC, though NIOC has said Total may continue to negotiate the downstream LNG segment of the project.

South Pars phases 15-16 are being developed by Iranian company Khatam ol Anbia, an engineering arm of the Revolutionary Guards, but the project is way behind schedule because the company doesn't have a viable development plan and is short of cash and manpower.

South Pars 17-18 is also being developed by local firms, but faces delays as needed pipelines were diverted to the Salman-Assaluyeh offshore pipeline and it will take 14 months for new ones to arrive. Local firms have also won development contracts for South Pars 19-22. South Pars 21-22 was awarded to the Offshore Industries Engineering and Construction Company.

South Pars phases 27-28 are likely to go to Petropars. The company's director recently said it may partner with a foreign firm. But the development of South Pars, the world's single biggest concentration of non-associated gas, has not met original deadlines largely because of the involvement of overstretched local companies, and Iran remains a net importer of gas.

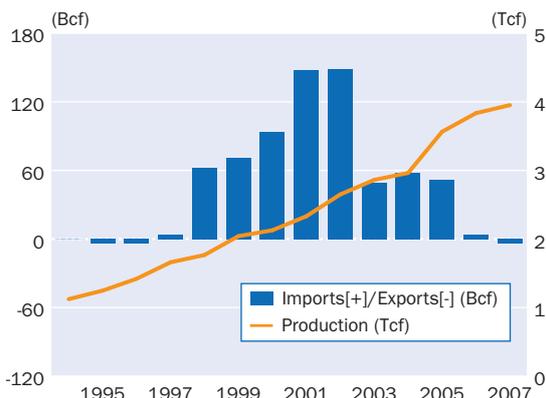
Gasoline deficit

The refining sector is also lagging behind with Iran being forced to import large volumes of gasoline as domestic capacity cannot cope with high demand in a subsidized market. No substantial progress has been made on plans to build grassroots refineries, owing to difficulties in arranging finance from foreign sources.

A recent report by the National Iranian Oil Refining and Distribution Co. said all refining projects were running behind schedule. Refining projects designed to have phased out gasoline imports by end-2009 were one to two years late because of a funding shortage, weak oil ministry planning and international financial sanctions.

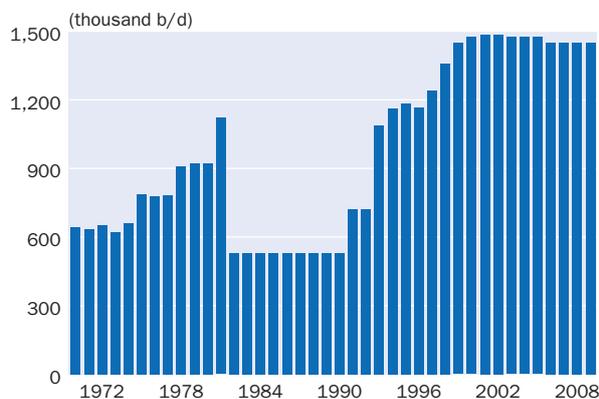
National gasoline output is currently 44.637 million liters/day from the Abadan, Arak, Esfahan, Bandar Abbas, Tabriz, Tehran, Shiraz, Kermanshah and Lavan refineries. Domestic consumption is 64 million liters/d. Some moves are afoot in parliament to reduce the quota for gasoline rationing from 100 million liters per month to 80 or even less in 2009. This issue took on added urgency after moves by the US senate to impose sanctions on Iran's gasoline suppliers.

Iran gas production and exports



Source: EIA

Iranian crude oil distillation capacity



Source: EIA

In 2006, the government launched a plan to raise gasoline production to 68 million liters/d. It also planned to invest \$24 billion to build seven new refineries to raise production further to 107 million liters/d. But three years into the plan, only \$723 million of these funds have been disbursed, of which \$618 million was allocated to the Star of Persian Gulf condensate refinery, which is only 18% complete.

Of the other new refineries, the Hormuz refinery is only 3.5% complete, Khuzestan 2%, Pars 5.18%, Shahriar 3%, while the Anahita and Caspian refinery projects are not thought to have moved forward at all. The Star refinery project will require total investment of \$3.24 billion and is unlikely to come on stream by the 2010 target date.

'Privatization' strategy

Another key plank of future oil policy is privatization. Around 114 subsidiaries of NIOC are slated to be privatized, yet very little progress has been made since the process began at the start of the decade. Around 95% of Petroliran, an NIOC subsidiary, was sold to the private Iranian firm Dana Energy in November 2008 for \$100 million. The IPO was suspended on the president's orders after media reports criticized the low price paid by Dana and objections were made to the "strategic nature of projects handled by Petroliran." It was announced in May that all issues related to the IPO had been resolved after the Auditor General deemed the sale legitimate.

A consortium made up of Khatam ol-Anbia Reconstruction Headquarters, the engineering arm of the Revolutionary Guards, private Iranian company Kayson and the Mashhad-based Razavi group, reportedly paid \$212 million for 61% of Petropars, which handles several phases of the South Pars development. But the Guards Corps later denied being part of the deal. Ali Kardor, NIOC's privatization director, said that Petropars had been bought by a group of Iranian expatriates.

Khatam ol-Anbia also bought 61% of troubled Sadra, an offshore engineering company. There was no other bidder for this IPO. Other equity holders in Sadra opted to sell their shares soon after the purchase while the share price was on the rise.

The hope is that the privately-run firms will accelerate the pace of development without being shackled by political disputes and budgetary constraints, but the process has been slow to produce tangible results.

Ahmadinejad is likely to hang on to power, but it is clear that the early months of the new presidency will be far from an easy ride given the biggest public demonstrations in the country since the 1979 Islamic Revolution. In addition, Ahmadinejad's economic policies have not addressed the weaknesses of an oil and gas industry that desperately needs an injection of new capital and new technology. The disputed election has added an element of political instability to an already unsteady economic story.

Ukraine struggles to meet Russian cash call

The threat of a disruption to European gas supplies has become a monthly event on the gas market calendar as Ukraine's Naftogaz struggles to pay its Russian task master Gazprom. A new agreement on gas transit is needed. Perversely, if a stable framework governing the gas flow through Ukraine could be agreed, Europe might conclude that it has less to fear from greater dependence on Russian gas. **Paul Whitehead and Alex Bor**

Since the first Ukraine-Russia gas crisis in winter 2005/06, the threat of an interruption to European gas supplies has become an almost annual event. However, the agreement reached January 19 following the latest stand-off has turned the threat into a monthly occurrence as state-owned Ukrainian gas company Naftogaz struggles to meet cash calls from Russian state gas monopoly Gazprom. According to the deal, Naftogaz must make monthly payments for gas supplies within seven days of the end of each month. Russian Prime Minister Vladimir Putin has threatened to shut off the gas if the payments are not made.

In June, Ukrainian President Viktor Yushchenko had to ask the National Bank of Ukraine to provide Hyrvnias 3.8 billion (\$500 million) to help Naftogaz pay for Russian gas imports in May. Putin said that Naftogaz's finances were so bad that the company might default on the payment in July, triggering gas supply disruptions. The May payment for April gas was only made when Naftogaz borrowed \$450 million from Gazprom, putting it further in hock to the Russian company. Naftogaz has racked up debts of \$2.15 billion to Gazprom this year. According to Iryna Vannikova, a spokeswoman for Yushchenko, Naftogaz's total debts are estimated at Hyrvnias 59.8 billion, while total revenues this year will amount to just Hyrvnias 59 billion.

Ukraine's financing problems are in part a result of the terms of the January gas agreement and the current economic downturn. Hit by a severe economic crisis and 33% decline in industrial output in first-quarter 2009, Ukraine expects to consume just 33 Bcm of Russian gas in 2009, down from the 40 Bcm originally anticipated. The agreement allows Gazprom to impose sanctions against Naftogaz for lower import volumes.

But Naftogaz's problems do not stem solely from the gas supply agreement with Gazprom. Ukrainian Prime Minister Yulia Tymoshenko is sticking by her policy of buying natural gas from Gazprom and then re-selling it domestically at an 80% discount, a practice that causes severe financial losses for Naftogaz. Tymoshenko made an election promise that gas prices will not increase this year. She has also pledged to run as a candidate in Ukraine's January 2010 presidential election.

Potential solutions

Forecasts for the EU's growing dependence on natural gas imports means that it needs additional gas supply, but equally cannot afford to have a permanent source of tension governing an existing major transit route. From

the European perspective, new gas supply routes are not designed to displace gas transiting Ukraine, but to replace expected decline in EU output. New supply is needed in addition to Ukrainian transit volumes.

However, the immediate concern is not just a supply disruption over the summer but the possibility that Ukraine will be unable to store enough gas for the winter. The European Commission has called for an "in-depth review" of the potential impact; if Ukraine fails to store sufficient gas, the fear is that it will tap European-bound transit volumes to meet its needs, sparking a new row with Gazprom, leading to either a reduction or complete halt to gas flows through the country.

To address this problem, the Commission chaired in June a meeting of the Gas Coordination Group, comprising representatives from the EU national governments, the gas industry and energy regulators in Brussels. Gazprom and Naftogaz were also invited. A further meeting is planned for July 2.

From Moscow's viewpoint, its development of the Nord Stream and South Stream gas pipelines to Europe are more specifically focused on reducing its dependence on Ukraine, through which 80% of its gas exports to Europe flow, as well as securing its share of a growing European market. Prospective pipelines heading east towards Asia and LNG liquefaction capacity are designed to broaden the markets for Russian gas and allow flexibility in switching supplies towards the highest priced areas.

As a result, there are a number of solutions to the current problem, not all of them palatable. Gazprom, which has an understandable desire to receive payment for its gas in a timely fashion, would resist yet another renegotiation of the contract terms and prices. For its part, Kiev will not countenance an exchange of debt for a stake in Ukraine's gas system, a partnership solution that in another context – one divorced from the context of Russo-Ukrainian political relations – might otherwise appear quite rational.

The alternatives are the creation of a stable framework governing gas transit through Ukraine, which would have to include either an internal or external solution to Naftogaz' chronic financing problems, or the development of alternative transit routes. In reality, both are required and neither are likely in the short term.

However, there are some moves to address the issue of finance. Representatives of the European Commission

are to meet with financial institutions, including the IMF, and representatives from the gas industry to discuss whether finance can be arranged to help Ukraine pay for Russian gas. European Commission President Jose Manuel Barroso said June 19 that: "There was no decision regarding finance from the EU. This is primarily a decision for Russia and Ukraine," but he also said that he would discuss the possibility of arranging some "short-term, stop-gap" funding to help Ukraine.

In response to questions about Ukrainian requests for \$4.2 billion to help it pay for gas, Barroso said: "We don't have that money in the budget. We want to help our Ukrainian friends but they have a structural problem... The basic problem is with Ukraine's ability to

pay for its gas supplies from Russia, but that is not our problem. We cannot spend the Community budget on that, but we will see whether others can make a certain effort or contribution," he added.

According to Yushchenko, Naftogaz faces \$3.5 billion in losses this year unless its renegotiates its agreement with Gazprom. "It is impossible to change the financial situation of Naftogaz without changing the agreement signed with Gazprom on gas transit," Yushchenko's economic department said.

In the interim, Tymoshenko has put forward a plan to increase the capital of Naftogaz to help the company pay its debts. The government will seek to use budget

Russia's gas transportation network: main arteries



Source: Platts

revenue to infuse Naftogaz capital with up to Hryvnias 18 billion Tymoshenko said in June, adding that budget amendments will be submitted to parliament. The plan would help Naftogaz pay off debts owed to state-owned Ukrainian banks Oshchadbank and Ukreximbank. Loans from the two banks of 12 billion hryvnias were taken out in December to help pay for gas supplies in 2008.

A way forward for Ukraine

A group of independent experts, the Wien group, recently presented proposals to help avoid future gas disputes between Russia and Ukraine. "Unless steps are taken now, a similar supply interruption and associated crisis could occur again, possibly later this year and/or in early 2010," the group presciently warned.

It urged European stakeholders to bring in a mechanism to provide bridging finance (for example bank guarantees for payment of at least one month's gas) backed by the World Bank, European Bank for Reconstruction and Development and commercial banks.

It also suggested the EU keep its monitoring mission in Ukraine to facilitate information exchange. But, crucially, it urged the EU to guarantee the implementation of the provisions of the Energy Charter Treaty on transit disputes, and to make clear that the January crisis has done severe long term "image damage" and brought uncertainty over the future of gas as a fuel. The EU should "establish a level playing field" for all three groups of stakeholders, and consider setting up an independent auditor to assess transit data, it says.

It asks the Ukrainian side to give other stakeholders an "early warning" – at least two weeks ahead – of its likely inability to pay for gas supplies, or to amass sufficient gas in storage ahead of the winter. Ukraine should also provide "transparent information about physical and swap gas flows including transit, domestic supply, storage and requirements for technical gas." And, finally, it recommends Ukraine set out its interpretation of its obligations under the ECT on transit of Russian gas, and when it feels an interruption is justified.

For their part, Russian stakeholders are urged to make clear "well in advance the anticipated consequences of potential contractual failures on the part of the Ukrainian stakeholders – including non-payment, late payment, insufficient minimum purchase volumes or other potential failure." It also suggests that the Russian side spells out its interpretation of what would happen if there were insufficient stocks in Ukrainian storage for Ukraine's own consumption during the coming winter.

Time for a new treaty?

The ECT, to which the Wien group refers, is a 200-page document that "establishes a legal framework in order to promote long-term cooperation in the energy field, based on complementarities and mutual benefits in accordance with the objectives and principles of the

EU member states' level of dependence on Russian-supplied gas

Country	Imports from Russia (Bcm)	Dependence on Russia (%)
Bulgaria	3.1	100%
Slovakia	5.8	98%
Greece	2.9	72.5%
Austria	5.6	63%
Czech Republic	6.4	72%
Slovenia	0.6	60%
Hungary	7.9	67%
Poland	6.2	45%
Romania	2.5	15%
Germany	35.6	43%
Italy	23.8	31%
France	7.6	18%
Turkey	23.2	66%
Serbia	1.9	100%
Bosnia and Herzegovina		100%

Source: European Commission/BP Statistical Review of World Energy (2008)

Proposed Russian gas export pipelines

Nord Stream

(first section under construction, gas expected Q4 2011)
Capacity: 27.5-55.0 Bcm/yr
Transit countries: None
Markets: Germany

South Stream

(proposal under active development)
Capacity: 31-63 Bcm/yr
Transit countries: Multiple
Markets: Southern branch: Bulgaria, Greece, southern Italy. Northern branch: Bulgaria, Serbia, Hungary, Slovenia, northern Italy, Austria and onwards

Yamal II

(project on hold)
Capacity: 23-33 Bcm/yr
Transit countries: Belarus
Markets: Poland, Slovakia, Czech, Austria, Germany, France, Switzerland, Slovenia, Croatia, Italy

Bluestream II

(speculative)
Capacity: Uncertain
Transit countries: None
Markets: Turkey

Source: Platts

Charter". It was signed by 51 countries in 1994 and entered into force in 1998. But Russia, along with Belarus and Norway, amongst others, have not ratified the treaty. Moscow, in particular, is unhappy about its transit protocol.

Russian non-ratification means that it is only applied provisionally in Russia and so cannot be invoked in any dispute involving Russia, such as those over gas transit with Ukraine. Nor is Russia likely to sign the treaty any time soon. In fact, in April this year, Russian President

Existing Russian gas export pipelines to Europe

Transit country	Capacity (Bcm/yr)	Russian export capacity (%)	Markets
Ukraine	102		Slovakia, Czech, Austria, Germany, France, Switzerland, Slovenia, Croatia, Italy
Ukraine	5		Poland
Ukraine	11		Hungary, Serbia, Bosnia
Ukraine	2		Romania
Ukraine	24		Romania, Bulgaria, Greece, Turkey, Macedonia
Sub-total	144	70.9	
Belarus	31		Poland, Germany, Netherlands, Belgium, UK
Belarus	5		Poland
Sub-total	36	17.8	
None	7		Finland
None	16		Turkey, Greece
sub-total	23	11.3	
Grand total	203	100.0	

Source: Platts

Dimitry Medvedev floated the idea of a new treaty to replace the ECT. Russia believes that the charter mainly meets the interests of energy consumers rather than producers, and that it has failed to prove its effectiveness, in particular during the dispute with Ukraine at the start of the year. Speaking in the wake of that dispute, Medvedev said that even though Ukraine had ratified the treaty, it did not abide by its principles. Russia wants either a new treaty or a revised ECT to provide the framework for resolving such disputes in court rather than at the political level.

The Russian proposal, which unlike the ECT would include nuclear energy, takes a different legal form to the ECT, and extends to other countries, including some of the world's largest: Canada, the USA, China, India and Norway, a major oil and gas exporter, all of which are missing from the ECT. The Russian document was delivered first to Finland, during a state visit in April, and then circulated to the G20, other FSU countries, and agencies such as the European Commission.

However, there is little political will beyond Russia to reinvent or replace the existing treaty. At a recent conference hosted by the European Investment Bank and the Energy Charter Secretariat, Professor Peter Cameron, a law specialist from the University of Dundee, was skeptical that there would be any new treaty. "It would take a very long time to negotiate any new treaty and the climate of optimism about East-West cooperation and trade that existed at the time the ECT was negotiated has gone, probably forever," he said.

However, he thought there was an appetite to revise the treaty to include specific measures on transit, especially given the Russia-Ukraine gas crises. "Perhaps we need a minor mechanism to deal with disputes on transit, but not another treaty . . . New initiatives in law will have greater success in the current environment if they are focused and specific, not wide-ranging as was the case when the ECT was drafted," he said.

New pipeline, new chokepoints

According to Philippe Hochart, vice president for the Caspian and Iran at French gas major GDF Suez, the solution lies not just in enhancing security of supply on existing gas transit routes, like Ukraine, but also in building new routes. "Gas buyers need to find common solutions for securing transit and a diversity of gas pipeline routes must be supported," he said.

However, it is evident that new routes are no quick fix. ECT Secretary-General Andre Mernier said, "security of supply depends not just on supplies but on transit, and the solutions need new routes that will take years to build – we risk entering a very dangerous period in the years to come." His point was that new gas pipelines can hardly avoid new transit chokepoints.

The Ukraine-Russia crisis and the desire for new gas pipelines both highlight the need to create a stable framework for cross border infrastructure investment and the resolution of transit disputes. From Moscow's perspective, alternative routes to Europe, and more particularly excess export capacity, would reduce its dependence on Ukraine, but still leave it reliant on other countries. From Europe's viewpoint, it wants both secure transit on Russian-supplied pipelines, but also other options besides Russian gas, should they be needed.

However, both sides' concerns might be addressed through an addendum on transit to the ECT. Europe fears greater dependence on Russian gas because of the problems it has experienced with supply through Ukraine. Conversely, if a stable framework governing transit through Ukraine could be agreed, Europe might feel less threatened by new Russian pipelines. Moreover, there is a reason why Russia built its pipes through Ukraine (and Belarus) in the first place; it is the shortest and the cheapest route to market. The price of bad relations between Moscow and Kiev can be counted not just in recurrent supply crises, but in the additional billion dollar costs of the alternative pipeline routes.

LNG market hit by US gas glut

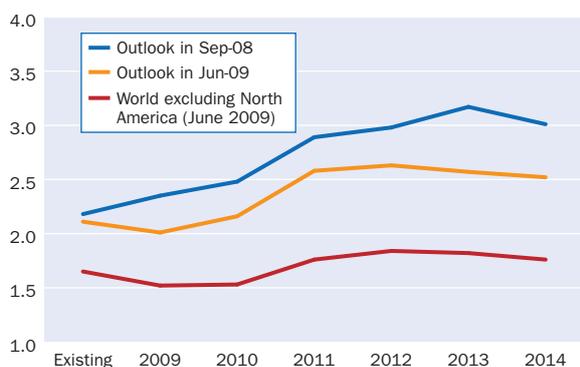
From supply crunch to supply surplus, the US unconventional gas boom has worldwide implications for the LNG market. With the US a market of last resort, and demand growth from non-OECD Asia constrained by a lack of infrastructure, Europe will play the pivotal role in determining future LNG demand. This pits pipelines against LNG vessels and will test gas producers' ability to manage supply. **Ross McCracken**

Nine months is a long time in the world of LNG. Since September 2008, the ratio of LNG regasification terminals to liquefaction capacity has fallen as expected, as more liquefaction capacity has come on-stream. This has been the result of increased capacity in Qatar and from the Sakhalin project in Russia, which have brought world liquefaction nameplate capacity to 297.2 Bcm a year, up 6.8% from September.

By contrast, regasification capacity has risen more slowly as projects have been delayed. Regas capacity has increased by just 3.3% over the period, owing to big increases in the UK, India and to a lesser extent in Brazil, Argentina and Chile. Total world regasification capacity is estimated at 626.35 Bcm/yr in June, compared with 606.31 Bcm/yr in September. There is some doubt over Japan's Sodegaura LNG terminal, where capacity was formerly put at 38 Bcm/yr. Officials announcing an expansion of the plant in March gave figures that suggested capacity was about 20 Bcm/yr.

The longer-term trend for the ratio remains upward, but not nearly so dramatically as the data suggested only nine months ago. The data takes into account all existing LNG liquefaction and regasification plant, projects under construction and for which approvals have been made or applied for. Plant at the proposal stage is ignored. In September, the ratio of liquefaction to regas capacity had been expected to rise from 2.17:1 to 3.17:1 by 2013, before falling back in 2014 to 3.01:1. By June this year, the same data set shows a rise from an expected 2.01:1 by end-2009 to 2.62:1 in 2012, falling back to 2.52:1 in 2014.

The changing ratio of world liquefaction to regasification capacity



Source: EIA

At the same time, the number of proposed regasification plants has risen, with marked regional variation – up 8 in Asia, but down 3 in North America and down 2 in Europe. In some cases projects have moved along the project line, but the retrenchment in the US is clear. 12 US regas terminal proposals have been withdrawn, suspended or rejected. Yet the number of countries actively considering new regas terminals has risen. New hopefuls include Bulgaria, Canada, New Zealand, South Korea and Sri Lanka.

US calamity

The starkest change in the LNG market has come in the US and the implications run worldwide. Not only has demand been hit by the recession, but the boom in unconventional gas supply has created a low-cost domestic alternative to LNG imports. The recession might be seen as a short-to-medium term setback, but the supply change is much more fundamental. The turnaround is stark, suggesting billions of dollars invested in LNG regas capacity has been wasted.

In 2005, the US Energy Information Administration forecast steadily rising annual imports of LNG, rising to over 170 Bcm/yr in 2022. By contrast, the EIA's 2009 Annual Energy Outlook estimates that imports will reach a peak in 2018 of just 42.5 Bcm/yr, falling to 24.1 Bcm/yr in 2030. Not only that, but the rise to 2018 is no longer predicated on a supply deficit necessitating higher imports, but on an expected excess of LNG in the world market that will be taken into the US as a default option, owing to its large capacity to receive and store natural gas.

Yet the US already has regasification capacity of 116.2 Bcm/yr. In September, there was an extraordinary further 288.8 Bcm/yr in the pipeline out to 2014. This has shrunk to 161.1 Bcm/yr and is almost certain to diminish further. With the excess of capacity so high, few planned projects are likely to go ahead. It is notable that in September, according to company plans, US regas capacity was expected to increase by 27.3 Bcm/yr in last-quarter 2008 and by a further 28.5 Bcm/yr in 2009. None of this has yet materialized. An increase of 26.2 Bcm/yr is still expected this year and a further 58.4 and 61 Bcm/yr in 2010 and 2011 respectively, but the chances are that these plans too will evaporate.

The abundance of US gas and regas capacity will have knock-on effects for the Canadian and Mexican markets, where LNG regas terminals are also being considered, as well for plans to bring Arctic gas by pipeline from the

Alaskan North Slope and Mackenzie Delta. In the EIA's 2009 AEO, Alaskan North Slope gas is expected to arrive in the lower-48 from about 2018. Some 33.6 Bcm/yr of regas capacity is in the project pipeline in Canada, which is expected on-stream from 2009-2011, as well as 18.6 Bcm/yr in Mexico from 2011-2014. These projects too may fall by the wayside.

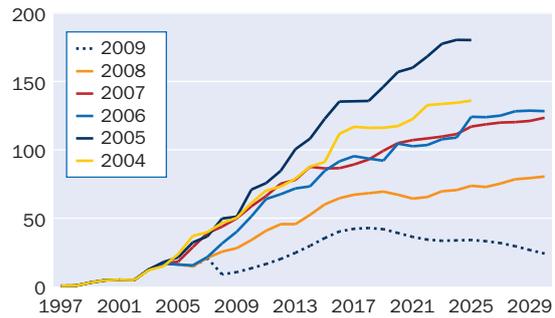
Europe builds regas capacity

By contrast, in Europe, there is no unconventional gas revolution, nor the immediate likelihood of one. Recession has undercut demand to such an extent that existing pipeline and LNG capacity is more than sufficient to meet current consumption. However, the medium to long-term outlook is governed by a steady decline in domestic production coupled with a revival in demand growth, principally from the continued expansion of gas-fired power generation.

Long-term estimates of gas demand show an increasing deficit in supply and increased reliance on imports. Following the recurrent crises over Russian gas supplies transiting Ukraine, LNG and alternative gas pipelines are seen as the main means of reducing dependence on Russian gas and increasing the region's security of supply.

Since September, European regas capacity has risen from 111.35 Bcm/yr to 132.65 Bcm/yr, principally owing to project completions in the UK. Notably, the number of countries that have moved along the project pipeline to get beyond the proposal stage now includes Croatia, Germany, Poland and Sweden, the former three all

EIA Annual Energy Outlook forecasts for US LNG imports (Bcm/yr) 2004-2009

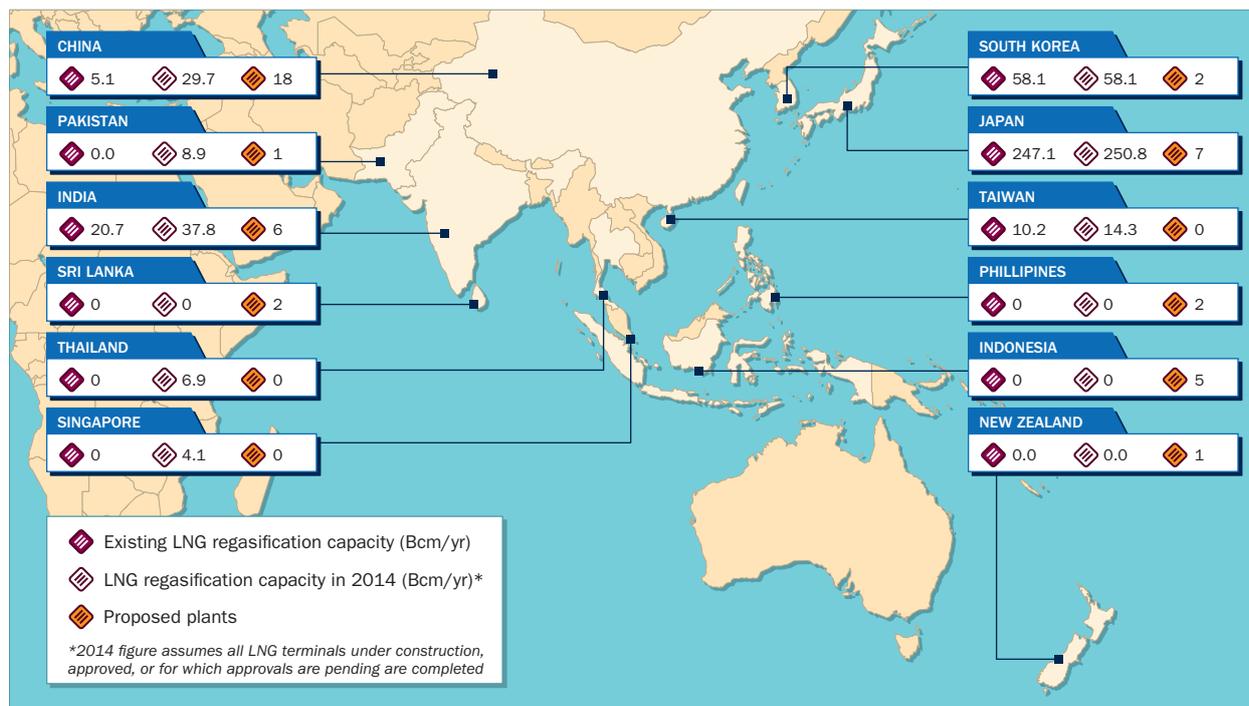


Source: EIA

heavily dependent on Russian pipeline gas. A Croatian regas terminal has the potential to act as an alternative gas entry point for other south and central European countries, where the reliance on Russian gas is at its most extreme.

Taking the project pipeline as a whole, in September, Europe could expect its total regas capacity to rise to 335.6 Bcm/yr by 2014. It can now expect an increase to 366.1 Bcm/yr, although this rise from September to June is heavily dependent on a 20 Bcm/yr project in Albania, for which permits have been approved. Demonstrating that security of supply is a key driver behind LNG, this terminal too is likely to be predicated on the onward transmission of gas to other southern European countries.

Existing and expected LNG regasification capacity in Asia



Source: Platts

World LNG liquefaction and regasification capacity (Bcm/yr)

Tables include existing LNG plants, those under construction, approved, or for which approvals are pending

	Existing	2009	2010	2011	2012	2013	2014
Liquefaction							
Total (additions)	297.2	58.3	23.3	10.7	15.6	20.4	35.3
Total (cumulative)	297.2	355.5	378.8	389.5	405.1	425.5	460.8
Regasification							
Total (additions)	626.35	86.46	105.8	186.96	59.3	29.3	65.4
Total (cumulative)	626.35	712.81	818.61	1005.57	1064.87	1094.17	1159.57
Europe (additions)	132.65	32.75	16	68.1	55.2	24.9	36.5
Europe (cumulative)	132.7	165.4	181.4	249.5	304.7	329.6	366.1
Americas (additions)	152.5	44.6	75.2	81.7	0	0	28.9
Americas (cumulative)	152.5	197.1	272.3	354	354	354.0	382.9
Asia (additions)	341.2	9.11	14.6	37.16	4.1	4.4	0
Asia (cumulative)	341.2	350.31	364.91	402.07	406.17	410.57	410.57

An additional 94 regasification terminals have been proposed, 44 in Asia, 24 in the Americas and 26 in Europe.

An additional 73 liquefaction plants have been proposed worldwide

Source: Platts LNG Daily

The vast majority of additional capacity is planned for the UK and Italy and could be subject to delays resulting from the recent fall in demand. Italy would also benefit in supply terms from almost all of the myriad of new pipeline proposals designed to bring gas into Europe from Russia, Central Asia and the Middle East. In particular, Italian oil major Eni is committed to the South Stream gas pipeline in partnership with Russia's Gazprom, where a recent doubling of capacity was announced to 60 Bcm/yr to be delivered to Italy, south and central Europe. These pipelines, if built, will only impact the supply situation towards the end of the 2009-2014 timeframe, but as they look more likely to be realized, they might delay or suspend later plans for new LNG terminals.

Nevertheless, new LNG regas capacity is sure to make a significant contribution to Europe's security of supply. In 2007, the EU relied on Russia to provide 121.43 Bcm of total EU demand of 489.7 Bcm/yr, of which 290.0 Bcm were net gas imports. The EU currently assumes that it will need between 71 and 204 Bcm/yr in new imports between 2006 and 2020, when it estimates EU annual consumption at 502.7 Bcm and imports at 300.2 Bcm. This is largely because domestic production is expected to fall to around 127 Bcm/yr, with the shortfall made up with imports from a variety of countries.

On current plans, the EU could add 203.45 Bcm/yr of regas capacity by 2014, suggesting it would at least have the ability to meet a substantial part of its demand for new imports through this route. However, this should not be overstated. Total world LNG liquefaction capacity will rise by only 136.4 Bcm/yr over the same period and Europe is not the only market. Not all Europe's planned terminals will be completed. In addition, the EU's LNG

facilities would be concentrated in the Iberian peninsula, the UK and Italy, while the ability to move gas around the EU is constrained by a lack of interconnections. In this sense, the 33 Bcm/yr of regas capacity expected in 2012-2014 in the Netherlands is strategically more significant than the additional 37.9 Bcm/yr planned in the UK by 2012.

Asian demand growth limited

OECD Asia plans to make very few additions to its existing LNG regas capacity, although it is notable that the number of proposed new terminals in Japan has risen from 5 to 7 in the last nine months, while in South Korea proposals have increased from zero to 2. New Zealand has also put a project on the board.

Absent the downgrade to Japan's Sodegaura LNG terminal, existing regas capacity in Asia has only increased in the last nine months by about 8 Bcm/yr, owing to the completion of an expansion of the Dahej LNG terminal in India. India and China have huge latent long-term demand for gas across the residential, commercial, industrial and power generation sectors, but it is constrained both by government policy and by the slow development of reception and transmission infrastructure. They also both expect in the near term supply boosts from domestic production and, in China's case, pipeline imports.

To 2014, non-OECD Asia is expected to increase its regas capacity of 25.8 Bcm/yr relatively slowly, by 5 Bcm/yr this year and 10.9 Bcm/yr in 2010, before jumping by 37.16 Bcm/yr in 2011. Only 4.4 Bcm/yr is planned in the 2012-2014 period, bringing the total increase to 57.46 Bcm/yr by 2014, a quarter of the expected build in Europe. The number of proposed

LNG spot market requires greater flexibility

There are likely to be 120 million tons per annum (164.4 Bcm/yr) of “flexible” LNG supplies available for spot trading by 2015, making up 30% of the total global supply base, according to CEO of GDF Suez Global LNG (UK), Philip Olivier. In 2008, there were 35 mtpa (48 Bcm/yr) of flexible supplies available, making up a fifth of the total market. Half came from suppliers in the Middle East, he said. The significant increase in flexible supplies would mean that arbitrage margins on spot cargoes would be less from 2013 onwards, even if oil prices were high.

According to Olivier, diversions to Asia reached a record level in 2008, but the recession has resulted in a 10-20% drop in demand. However, the Pacific market should become short again by 2014, he added. Contrary to the expectations of some, the market was not seeing a “tsunami of LNG” going to the US, as the US is providing only low netbacks for producers, he said, although “the tide is rising.”

Meanwhile, sellers are facing a difficult choice between selling at low spot prices or reducing production. In the short to medium term, flexible LNG supplies should flow to Europe, Olivier argued, as Europe has the infrastructure to handle increased LNG imports, and the Russia/Ukraine crisis had stimulated interest in diversifying supplies.

Also speaking at the recent Gastech conference in Abu Dhabi, Khalid Sultan R Al Kuwari, marketing executive at Qatari LNG producer RasGas, told delegates that contract flexibility was key to balancing the global LNG market and accounting for seasonality, but that term contracts would remain the base of the supply market.

In the past, long-term LNG contracts have tended to be fairly restrictive concerning destinations. In the last few years, regional imbalances have created arbitrage opportunities, and buyers and sellers have diverted unwanted cargoes to other markets on an ad hoc basis, to capture the price difference. However, even the leading exponents of the practice find it difficult to arrange.

Introducing and standardizing flexibility on destination would be a big step forward, agreed commercial director at Spain’s Repsol Gas Natural LNG Stream business Alberto Alvarez. “To optimize market dynamics, LNG needs a swinging market to support it,” he said. Destination flexibility was being practiced “even though it’s not built into contracts,” but the increase in flexibility would not lead to price convergence.

Most LNG is still linked to crude oil, whereas US gas prices continue to be set by the cost of unconventional gas, he added. Buyers would not get rid of oil-linkage and true price convergence would have to wait until the US fully embraced LNG imports as a significant supply source, he said.

terminals has risen from 31 to 34, but few of these have moved down the project pipeline. Asia’s regas capacity as a whole will increase from 341.2 Bcm/yr to 410.57 Bcm/yr in 2014.

European demand center stage

It is important to note that the existence of LNG regas capacity does not imply demand of the same magnitude, as the US experience so amply demonstrates. Infrastructure investment has run far ahead of itself in the US, may do so in Europe, but arguably lags demand in non-OECD Asia, so it is reasonable to assume that capacity utilization in Asia will be much higher than in Europe and that both will be much higher than in the US.

If North America is stripped out of the equation – on the basis that it will show little net increase in demand for imports but act more as storage capacity – there is in fact only a small increase in the ratio of LNG liquefaction to regasification capacity to 2014. From 1.65:1 today, the ratio would rise to 1.84:1 in 2012, before falling to 1.76:1 in 2014. Regasification capacity without North America rises from 491.55 Bcm/yr now to 811.47 Bcm/yr (+65%) in 2014, while liquefaction capacity would be unchanged, increasing from 297.2 Bcm/year now to 460.8 Bcm/yr (+55%) in 2014.

The incredible overshoot in investment in US regasification capacity, predicated on increasing imports of LNG, created the perception that there would be a significant supply crunch in the LNG market. This in turn spurred investment in liquefaction capacity. The advent of unconventional gas in the US has left those LNG terminal investments high and dry and rebalanced the future outlook for the LNG market, where – if developing country demand falls in line with investment in LNG terminals – the critical element is now European demand.

A range of factors could still upset this new outlook, but certainly in the medium term, US interest in LNG is likely only when prices are low, implying that it will buy only when there is a lack of demand in other markets. In a tight LNG market, it will revert to its own resources. Growth in non-OECD Asian demand will be constrained by the lack of infrastructure investment despite the potential size of these markets, while there is little reason to expect a sustained surge in demand from OECD Asia.

These assumptions can of course be challenged, but the trend appears to leave Europe in a pivotal role, pitting the development of Russian and other pipelines against the more remote producers of LNG. However, whether this heralds a relatively stable low price outlook remains an open question. LNG producers ability to constrain supply is only just being tested. LNG prices are also determined more by the oil price than the spot LNG market, the emergence of which may prove a casualty of the current downturn.

SMEs face further borrowing pressure

Small and medium-sized energy companies' ability to raise capital is shrinking as banks consolidate their lending on established customers with large asset bases. SMEs can turn to mezzanine financiers, but even here the number of lenders has contracted, and the cost of borrowing has risen. This is placing a large constraint on a traditionally dynamic sector that plays a key role in the energy sector's fortunes. **Jayne Jung**

Despite talk of the "green shoots" of recovery, small to medium-sized enterprises are seeing their borrowing bases cut from under them. And even with higher oil prices, oil and gas firms are no exception. "The market is way too tight. You look out there and you see many of your peers having their borrowing bases cut in half," says Scott Allen, chief financial officer of ReoStar Energy Corporation, a \$6.5 million natural gas producer based in Fort Worth, Texas. In October, his firm secured a \$25 million credit facility. It is now weighing its options for raising additional capital.

Scott Johnson, Houston-based cofounder of mezzanine debt provider GasRock Capital, sees the same general trend. He observes that banks are now very clearly focused on existing clients, and some companies are seeing their borrowing bases reduced, often to below the level of their outstanding bank debt, he says. There are also whispers in the market that a large bank has recently limited its senior debt borrowing base transactions to firms with \$100 million in assets or more, cutting out the SME sector all together.

While not consistent across the board, during the April-May redetermination period, when firms' lending arrangements are reviewed, commercial banks reduced the borrowing base of some smaller companies involved in exploration and production in the US by as much as 50%, several industry sources say. All were in agreement

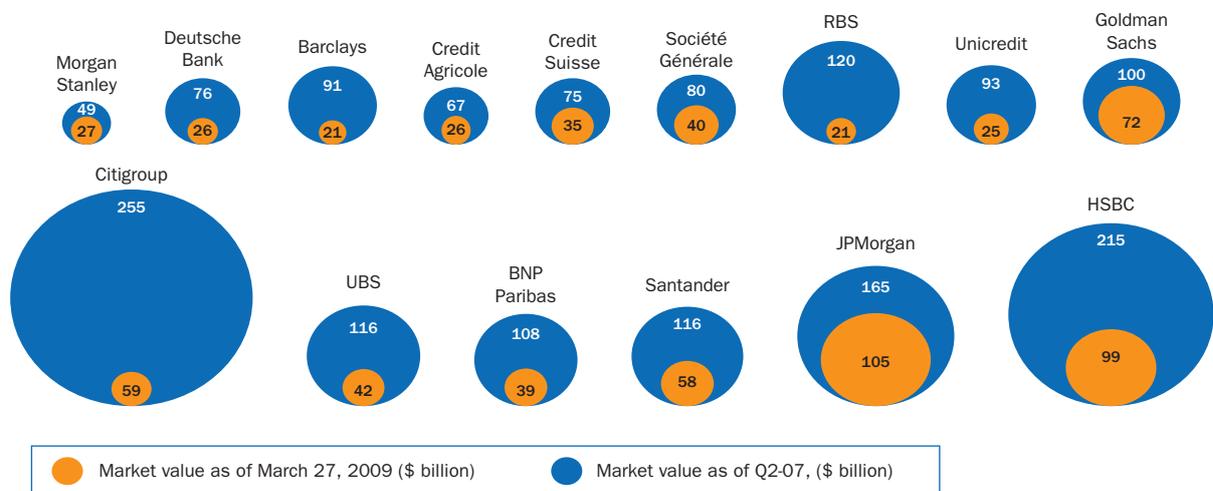
that this redetermination period would be easier than the next. Firms are likely to face more severe reductions with greater restrictions come October.

As a result, oil and gas companies will have to take on more junior debt, such as mezzanine, second lien or subordinated debt, in order to pay back their interest and principal to senior lenders. They may also end up having to raise equity or sell assets. They will certainly be limited in terms of new capital for investment.

According to Christopher Woodruff, an associate professor of economics at the University of California, San Diego, the smallest, fastest growing companies are likely to be hardest hit when there are limited resources. During a crisis, banks often perceive the smallest companies as having the riskiest loans and will restrict them first, or they might require excessive over-collateralization, such as large amounts of real estate. An October 2008 Federal Reserve Board Senior Loan Officer Survey showed that three-quarters of US banks have tightened their lending standards on small business loans.

In the energy space, restrictions in lending are tempered by pricing pressures or expected price increases – although those trends have been more difficult to forecast. For natural gas, the consensus among lenders is that prices will remain suppressed, while oil prices are expected to increase. Oil companies thus have an

Banks' shrinking market capitalization (\$ billion)



Source: Societe Generale

advantage over natural gas companies in their quest for capital. Borrowing bases are determined by the price of the commodity multiplied by the volume of output less costs. Derivative hedges to protect against falling prices are also factored in.

Redetermination results

In June, redetermination results were announced by the Nasdaq-traded oil & gas E&P company, GMX Resources. Its borrowing base was revised from \$190 million to \$175 million, while Bank of America became a participant, lending 14% of the total. The interest rate on its revolving credit facility was also changed, while an additional covenant was added: GMX Resources total debt to EBITDA (earnings before interest, taxes, depreciation, depletion and amortization) for the most recently ended twelve months cannot be greater than 4 to 1 on an ongoing basis.

The announcement came on the back of those made by US independents Stone Energy and Abraxas Energy Partners in late April. Stone said that its borrowing base had been approved by its bank group at \$425 million on its \$700 million credit facility. The company says it already had \$356 million in borrowings outstanding and another \$69 million in outstanding letters of credit, leaving no availability on the facility. In connection with the redetermination, Stone says it agreed to a 75 basis point increase on its borrowing base, which now ranges from LIBOR plus 2.25% to LIBOR plus 3%.

Abraxas said in May that the borrowing base of its 47%-owned Abraxas Energy Partners senior credit agreement had been reduced by 7% to \$130 million. Of that, Abraxas says \$125.6 million is currently outstanding. Chroma Oil & Gas, a private E&P company that produces about 200 b/d of oil and 15,200 Mcfd of natural gas, has seen its borrowing base decrease by 30%, although not to an amount below its outstanding debt, according to the company's Houston-based chief executive, Steven Mikel. Publicly-traded BreitBurn Energy Partners saw a 15% decrease, with its borrowing base falling to \$760 million from \$900 million, according to a company statement in mid-April.

Alternative finance

These mid and small-sized energy companies are taking a big hit not only from bank borrowing base reductions, but also from the sharp reduction in the number of mezzanine finance lenders, which formerly provided an alternative source of capital. Before August 2008, several hedge funds and large banks were notable as active mezzanine lenders. But many of them have exited the market or are sitting on the sidelines.

Lehman Brothers and New York-based hedge fund DB Zwirn are two that made headlines last year. But industry sources have also mentioned Petrobridge (a joint venture by DB Zwirn and another New York-based hedge fund, Fortress Investments) and Connecticut-based Silver Point Capital. Goldman Sachs also shut down a dedicated mezzanine financing unit in Houston several months ago. But according to a source familiar with the matter, the bank is "still willing and able to provide financing to the sector."

Indicative of the market stress are the higher rates of return required for mezzanine deals. Although significantly lower than their record highs in November, high-yield corporate bonds are trading around 10% at the low end and up to 14% at the high end – comparable returns for mezzanine finance. Higher corporate bond rates have raised the lower limit for mezzanine finance investors.

The latter ranges from 300 to 500 basis points more expensive than a year and a half ago, according to Wells Fargo. The bank targets a 15-25% rate of return for these deals. Meanwhile, ReoStar's Allen says that specialized mezzanine funds have requested an unpalatable 30% return from his firm. In addition, according to GasRock's Johnson, some lenders have at least doubled their equity requirements.

John Homier, chief executive at NGP Capital Resources in Houston, says bigger companies are taking on more mezzanine debt to shore up liquidity in the face of borrowing base reductions and lower cash flows. Homier says that this is an area where mezzanine financiers have plied their trade historically, but now it's taking on greater emphasis.

iTraxx Europe – loan margins for BBB credits



Source: Societe Generale

NGP Capital is currently reviewing a few deals with companies that have several hundreds of millions of dollars in assets. Traditionally mezzanine financing has been geared toward firms that have \$10 to \$100 million in assets. NGP Capital and GasRock have not been active in recent months, but continue to assess potential investments.

Mezzanine lending straddles debt and equity. There is no standard arrangement. But often the loan has a coupon with an equity “kicker” that results in a high interest premium to make them more attractive than the high-yield bond market. The advantage for companies taking it on is that in their accounts it appears as debt and can be financed from pre-tax revenue. If it was purely an equity investment, interest payments would be paid from post-tax profits.

But mezzanine debt is also more risky because it is non-senior debt. So, if a company goes bankrupt, senior (or proper) debt is paid first and only then does the mezzanine lender get a share. If that cannot be paid then the mezzanine lender is given equity instead, usually diluting the existing shareholders’ holdings. The mezzanine lender agrees to the less secure arrangement in return for a higher interest rate, with the backstop of some equity if things turn really bad. Getting some mezzanine lending is useful because it can unlock senior debt – a bank lender will like the idea that if losses do occur the mezzanine lender will take the hit first. With this buffer in place, the bank might be more willing to lend.

There are several mezzanine lenders still active in the market. They include DE Shaw, Macquarie, and Wells Fargo. “The space is very favorable for mezzanine finance currently. We see the senior lending market retracting, and the public/private equity markets are on hold. We feel that mezzanine finance will be able to fill that gap. We are in the right space at the right time,” says Todd Overbergen, Houston-based head of the direct capital unit’s energy group and a senior vice president at the D. E. Shaw group, a \$29 billion global investment firm.

The D. E. Shaw group’s direct capital unit has closed two deals in the energy sector since April. One was a \$50 million second lien facility with a large private equity-backed E&P company focused on natural gas resources. The second was a \$31 million equity and debt investment for a West Texas company focused on an oil resource play. Established in 2004, the energy part of D. E. Shaw group’s direct capital unit has invested over \$1 billion in the energy sector with approximately 60% of that money going toward upstream investments. The unit has a large pool of committed capital and is actively seeking investment opportunities.

Elsewhere, Macquarie has closed several deals in the last two months and is currently looking at around 20 projects. Wells Fargo Energy Capital recently completed a deal with BNK Petroleum, a California-based oil and gas exploration and production company focused on finding and exploiting

Federal subsidies support bank lending to renewables

The credit crunch appears to be having less of an effect on small businesses in the renewable energy market. Scott Sklar, president of the Stella Group, a Washington, D.C. based strategic marketing and policy firm for alternative energy users and companies, says clean technology firms are doing better than their small-to-medium sized counterparts “without a question”.

A large part of the reason is federal funding. In March, the US Department of Energy announced it would invest \$8 billion in state and local energy efficiency programs. Over \$2.7 billion in grants are now available under the Energy Efficiency and Conservation Block Grant Program, which is part of the American Recovery and Reinvestment Act of 2009. The grants aim to help families save money on their electricity and gas bills, and at the same time create about 87,000 new jobs. Sklar expects the government funds will create a robust residential market primarily for photovoltaics and small wind companies starting from July. Other markets expected to benefit from stimulus money available from September are solar water heating, solar day lighting, geothermal heat pumps, and advanced windows.

The Stella Group estimates that in 2010 the US alternative energy space will reach \$33 billion, up from about \$30 billion now and \$25 billion a year ago. “Clean tech companies are mimicking the computer and cellular phone market. They are becoming standardized, modularized and miniaturized,” says Sklar. “It’s good news, but it takes time. A lot of people think cell phones appeared out of nowhere, but it took forty years and we’re pretty much on the same track.” He reckons that the renewable energy market is 20 years in its trajectory to becoming a mainstream phenomena. Let’s just hope it doesn’t stop half way there.

large oil and gas resource plays. On April 23, the E&P firm agreed a \$50 million credit facility. The facility replaced the company’s existing \$7 million credit line and has an initial borrowing base of \$29.5 million. It was collateralized by the company’s real estate in the Tishomingo gas field in Oklahoma, with the funds maturing within 24 months and bearing interest at a US base rate plus 3%, overriding royalties and net profit interests included. The proceeds will be used to complete the drilling of BNK’s wells.

“The debt capital market has certainly improved, so the bigger companies have access to the high grade debt and high yield market. Both of those markets have been quite strong. But the mezzanine and second lien market are still going to be very tight for the foreseeable future,” says Mark Green, Houston-based senior vice president in Wells Fargo Energy Group.

Deals are getting done, but at a price, and compared to the hundreds of energy SMEs running today, the available capital is unlikely to fill the growing gap between those that need it and those that get it. Limited access to capital and higher borrowing costs reduce companies’ ability to invest and expand, and in the current market SMEs face both constraints. This in itself will make it harder for those green shoots of recovery to push through the subsoil.

Bolivia – missing the natural gas boat

Bolivia's government needs foreign investors to expand its output of natural gas. Business plans that promise new investment have gradually emerged under the nationalized regime, but the country has already lost future market share in the region to LNG. Moreover, neither the capital nor trust exists to build a new pipeline to Argentina, which would ensure a market for expanding Bolivian gas exports. **Charles Newbery**

For Luis Carlos Kinn, Bolivia has a bright future for natural gas investment. He runs Gas To Liquids International, a Bolivian venture that's developing the El Palmar gas field in the tropical lowlands of the country's east and is preparing to explore four others in a 40-60 partnership with Yacimientos Petroliferos Fiscales Bolivianos (YPFB), the state oil company that controls the industry and its vast reserves. One of these four fields is thought to have major gas production potential.

Kinn hopes to put the first El Palmar well into commercial production in July, while at the same time drilling a second well. He estimates each will provide output of about 198,000 cubic meters per day. GTLI will sell the gas domestically and to Argentina. GTLI also has a contract to sell to its parent company, India's Jindal Steel & Power. Jindal is developing El Mutun, which, when complete, will be the world's biggest iron ore mine. The mine and related projects in the eastern lowlands of Bolivia will consume 8 MMcmd of gas by 2017, gradually increasing in the years before that.

To meet this demand, Kinn has his work cut out for him. But he's not sweating. "Only 8% of the area (of Bolivia) has been explored or is in development," he said. "There is still a lot to discover." This potential for production, sales and profits is what has driven investors to Bolivia for years, with multinationals like Brazil's Petrobras, Britain's BG Group, France's Total and Spain's Repsol setting up or stepping up operations after the government opened the sector to more private investment in 1990.

An export deal with Brazil in 1993 helped make it possible to increase production, now at 40 MMcmd. Of that, about 34 MMcmd is exported to Argentina and Brazil. Testimony to the private investment, production has risen from 11.3 MMcmd in the 1970s and from 15.6 MMcmd in 2000.

However, in 2006, the government nationalized the gas sector, prompting investors to put exploration projects – as well as the construction and expansion of pipelines and distribution systems – on the backburner. They pulled back to focus on maintaining assets, worried about the viability of their businesses as the government took over fields, pipelines and refineries. The government's action was supported by the majority indigenous population that has long protested against the private gas sector and subservience to the country's white minority.

In the last few years, the government has negotiated regulations and commercial deals with foreign and private producers so they could draft business plans

under the nationalized regime. This year, a dozen or so companies vowed to invest a total of more than \$1 billion to increase gas output to 44.68 MMcmd by end-2009. "There are advances in the energy field," said Yussef Akly, the strategy and coordination manager of the Bolivian Hydrocarbons Chamber, an industry group for private companies. "But we think things could move forward at a more accelerated pace."

Too little too late?

Geologically, Bolivia is attractive. It has an estimated 53.3 Tcf (1.5 Tcm) of proven and potential gas reserves, the second largest in South America after Venezuela's likely 171 Tcf. Bolivia's reserves are expected to rise with further exploration, and most of it is exportable, owing to a limited domestic market. However, without investment, most of the gas will remain in the ground and Bolivia may lose out to the global LNG business in the race to supply its own backyard.

Bolivia's sluggish development of reserves since 2006 has led big gas consumers like Argentina, Brazil and Chile to look elsewhere for supplies. They are diversifying energy grids to reduce their reliance on gas. Brazil is developing its own gas, and Argentina hopes eventually to end a five-year decline and expand its gas output. All three are now buying LNG.

"The region cannot wait for Bolivia to stabilize," said Gianna Bern, president of Brookshire Advisory and Research in Flossmoor, Illinois. "Where there is a need, the market will come up with a solution, and LNG is bubbling up as the energy of choice for insulating them from future risks."

In 2006, Argentina negotiated a deal with Bolivia for the supply of between 4.6 and 7.7 MMcmd, an amount that was to increase gradually to 27.7 MMcmd by 2010. Argentina drew up blueprints for an extensive pipeline system to bring in the new supplies. But Bolivia's nationalization kept investors away from the project, owing to concern that the gas to fill the line wouldn't materialize.

This forced Argentina to turn to LNG for the first time in 2008, accepting a huge mark-up in price so that it could plug a mushrooming gas deficit at home that reached 40 MMcmd in 2007, or a third of average demand. It purchased LNG on the spot market at \$16-18/MMBtu, higher than the \$10-12/MMBtu gas price prevailing at the time in the US, and much higher than either domestic wellhead prices of \$1.50/MMBtu or the \$7.80-9.03/MMBtu it was paying for Bolivian supplies.

"Bolivia's neighbors want energy security and reliability, and La Paz is falling short in offering this," said RoseAnne Franco, the lead Latin American analyst for PFC Energy in Washington. "It is an issue of energy security. The proximity to gas supplies is not enough."

LNG competition

LNG's rise in South America is posing a problem for Evo Morales, the coca-growing street activist who became Bolivia's president in 2006 and championed the nationalization of the gas sector, a process that's still in the making. The country, the second poorest in the region, relies on gas for thousands of jobs and 30% of state revenue. Gas accounts for half of its exports.

Morales, who won the presidency with an unprecedented 54% of the votes, consolidated his popularity with the nationalization, and ended years of often bloody protests against the private gas sector. Control brought new wealth from gas exports. And the left-wing president has managed to maintain his position, despite setbacks like a recent bribery and murder scandal that led to the ouster and arrest of YPF's boss, Santos Ramirez. Morales is thought highly likely to win a second term at the December 6, 2009 election.

However, his popularity is by no means unshakeable and derives principally from the indigenous population. Opposition is fierce in some areas. Much rests on a new constitution inspired by his political party and approved this year in a public referendum. It calmed the explosive social tension of 2002-06, a period known as the 'gas war' that was marked by protests and riots by tens of thousands, leading to the deaths of more than 60 people and the end of two presidencies.

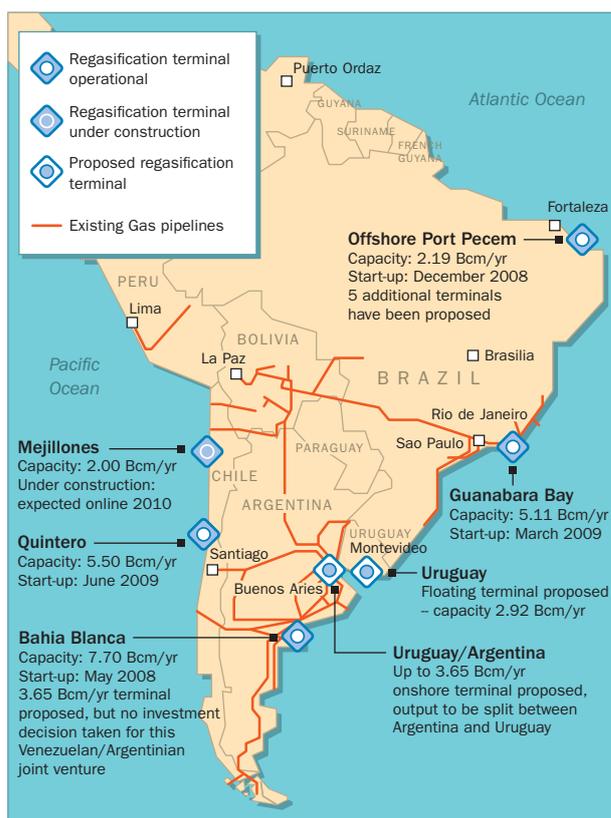
Within its 650 pages, the new constitution is full of contradictions, even in single paragraphs. It was drafted that way to satisfy everybody from the indigenous poor majority in the western highlands to the wealthier minority in the fertile, gas-rich lowlands to the east. "The constitution reads like a comedy club script," according to Peter Zeihan, vice president of strategic intelligence at Stratfor, a global intelligence company in Austin, Texas. "Everybody got everything they wanted into it."

Four challenges

As it now stands, Morales' model for the gas industry faces four big challenges, if it is to boost output and encourage investment. The first is to restore credibility and stability. "Bolivia's current track record will cause some investors to think twice. Nationalization makes it so that investors don't know how secure their assets will be," said Brookshire's Bern. "If your investment horizon is very long term then Bolivia is attractive because of its large reserves," she said. Otherwise, "it is a risky bet."

The second challenge is to transform YPFB into a skilled company capable of delivering new projects, for example by introducing a proficient training program and meeting supply commitments. When YPFB took over the industry,

South America turns to LNG



Source: Platts LNG Daily, Petrobras

it vowed to step up production and exports. But it has failed to meet its self-imposed targets. "If you have an experienced, well-run and capably managed company and you are having a tough time developing reserves anywhere in the world, how much harder it is for YPFB to do it without a structure or expertise," said Jose Luis Vittor, an energy expert at McDermott Will & Emery, an international law firm in Houston, Texas.

For this reason, YPFB will need to work with foreign companies, said Erasto Almeida, an analyst with Eurasia Group, a risk consultancy in New York. The government "would like to develop the gas reserves on its own with YPFB, but it lacks the capability so Morales needs foreign companies," he said. "This is the big constraint on his policy because companies will remain reluctant to invest while there are threats to take over gas assets."

Morales is beginning to understand that he has to develop better relationships with foreign companies in the quest to transform gas reserves into a business that will develop the economy and improve the livelihood of its people, he added. That has led to an improvement in regulations and dealings with the private sector, paving the way for a renewal of investment commitments this year, Almeida said.

The third challenge is to build and boost pipeline capacity and infrastructure to get more gas out of the ground and to consumers, according to Akly, of the

Bolivian Hydrocarbons Chamber. The local market offers growth in outlets for homes, factories, power plants and mines like El Mutun. Plans exist for facilities to make gas-derived liquids like propane as well as petrochemicals, including fertilizers for the country's soybean farms. This will build on current demand of 6 to 7 MMcmd.

But exports provide the largest opportunities. Energy-hungry Argentina, struggling to expand its own gas reserves, needs more gas, but must construct a new pipeline for a large increase in its purchases. There are possible new markets in Paraguay and Uruguay. But to get the gas there, new pipelines are again needed.

Argentina wants 27.7 MMcmd of gas, but has only received on average 4 MMcmd this year, Akly said. If a pipeline were built as planned, that would provide the incentive for producers to "multiply national production by two," he said. However, cash-strapped Argentina can't bankroll the \$1.8 billion cost of building the line. Nor do investors want to dive in, given the lack of available gas supplies in Bolivia and Argentina's history of renegeing on debt; it defaulted on nearly \$100 billion in 2001, the biggest in world history. "Argentines don't have two dimes to rub together to help out," said Zeihan.

The final challenge is wrapped up in the future of Brazil. Petrobras, that country's state oil giant, is the biggest investor in Bolivia's gas sector, with \$175 million earmarked for expanding production this year. Brazil needs gas to feed its economy, the tenth largest in the

world and fifth by population. This will help increase Bolivian output as Petrobras pumps more money into expanding its operations, said PFC Energy's Franco. But when Brazil's contract with Bolivia runs out in 2019, it may stop importing as part of an energy independence drive that involves developing its own offshore gas, which is thought to have enormous potential.

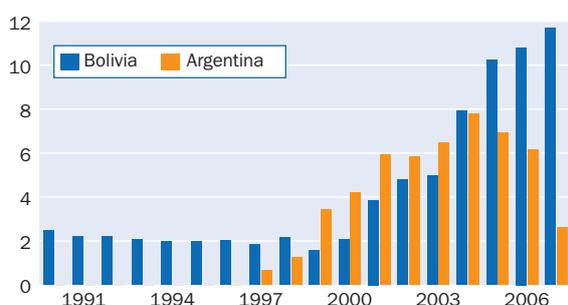
Securing a market

If there is a cutback in Brazilian demand, Bolivia will have to look elsewhere for sales opportunities, possibly beyond the region. A logical option is to export supplies in the form of LNG as Peru is preparing to do. The government is holding conversations on its LNG options, but it may prove "very difficult," according to Kinn.

The main hold up is that landlocked Bolivia has no access to a sea port. The easiest way to get gas to a liquefaction terminal would be via Chile. But Bolivia is refusing to deal with its neighbor until discussions begin on regaining access to the Pacific Ocean, which it lost after a four-year war with Chile in the 1870s. Bolivia has said it will export gas to Chile, if it is given back its access to the ocean. "The only way Bolivia can access international markets is if it buries its hatchet with Chile," Zeihan said. "Otherwise it has to toss that option out the window."

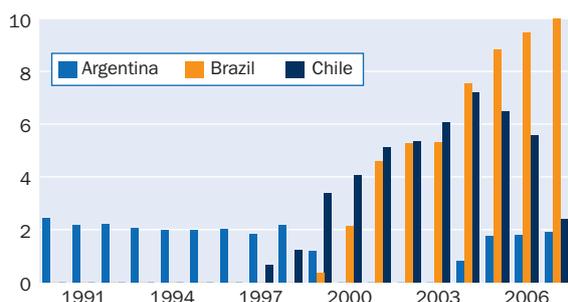
An alternative would be to arrange a deal with Argentina, which has a vast network of pipelines running across the Andes to Chile. If Argentina imports Bolivian gas for its market and exports its own supplies to Chile for shipping abroad as LNG, that could be a way of accessing international markets, said Eurasia's Almeida.

Natural gas exports (Bcm)



Source: EIA

Natural gas imports (Bcm)



Source: EIA

To its advantage, Bolivia can compete with global LNG suppliers on price. Regional pipeline supplies are cheaper than LNG, according to Julio Campos, an energy consultant in Mexico City for Frost & Sullivan, a business research and consulting firm. "Bolivia will always be cheaper" for gas supplies, agreed Gerardo Rabinovich, an energy expert at the University of Belgrano in Buenos Aires.

The risk is that it may be too late. Bolivia may increase production but "its potential customers may not want it," said Vittor, of McDermott Will & Emery. "Price is not the only factor. The certainty of supply is also important. Bolivia's gas could be more attractive than LNG or diesel or coal. But the country must become a reliable supplier, and to do that is no small task."

The expectation is that Bolivia's "legal and institutional order will remain weak and highly uncertain," said Michael Shifter, a Latin American analyst at the Inter-American Dialogue think-tank in Washington. "Investors in the energy sector will have to weigh the risks involved. Some will be lured by the potential rewards, while other investors will be discouraged. . . . "The most likely course for Bolivia," he said, "appears to be muddling through, averting a collapse of the natural gas industry, but failing to create the necessary conditions for sustained economic progress."

Sub-Saharan Africa: three in four lack power

The failure to provide electricity in sub-Saharan Africa reflects not just a lack of generating capacity, but a lack of transmission and distribution infrastructure. However, some countries with the right combination of political will, socio-economic goals and donor support are recording successes, while distributed power systems may provide a means around the inability to invest in delivery infrastructure. **Neil Ford**

Ensuring that even the remotest rural farmer and poorest urban dweller have reliable access to electricity was once the privilege of first world economies, but emerging markets in the Middle East, Latin America and North Africa can now boast electrification rates approaching 100%. The great exception remains sub-Saharan Africa, where just one person in four has access to electricity, a figure that falls to less than one in ten in rural areas.

It is easy to overlook the benefits of electricity. Electric cookers and refrigerators may be beyond the budget of most Africans, but electric light consumes little power and makes a huge difference to living standards. It provides security and enables school pupils to complete their homework after darkness. Mobile phones are often cited as an important tool in promoting trade in developing countries, but the lack of electricity makes recharging such phones yet another hurdle.

Insufficient generation

There are wide variations in the proportion of people with access to electricity in Africa. Tunisia tops the list with 99%, with only Mauritius breaking the North African monopoly at the top of the table. The six leading countries are among the most prosperous on the continent, so there is an obvious link between economic activity and access to electricity. However, three sub-Saharan countries have similar GDP to the best performers, at about \$4,000 per capita, but none are approaching universal coverage.

While the precise figures vary, most sources agree that no more than a quarter of the African population has access to electricity. Some countries like Chad and Burundi lack reliable statistics, but are among the continent's poorest and so would probably come at the bottom end of the table. Some of the figures should also be taken with a hint of caution. The Nigerian government claims that 49% of Nigerians have access to electricity, but this seems unlikely in a country with a population in excess of 140 million and an effective generating capacity of just 3 GW.

There is a general lack of generating capacity across Africa. Kenya, Uganda and Tanzania collectively have about 1 GW of generating capacity to serve every 30 million people, even when hydro schemes are operating at full power. By contrast, the same generating capacity supplies just 300,000 US citizens. It should also be noted that even those homes and businesses connected to their national grid often do not have constant access to electricity. Power rationing is common in many countries, particularly during the dry season when water

levels at hydro schemes are low. As a result, many commercial enterprises from grocery stores to huge mines rely on their own generators.

Downstream failings

Not only is there insufficient generating capacity in most African countries, but there is a lack of transmission and distribution. As with water, sewerage and fixed telephony infrastructure, most power grids were developed during the colonial era and in the heart of Africa's main cities. Such cities have grown massively, but their power grids have failed to keep up. The lack of access to electricity is often portrayed as a failure to connect rural areas, but in practice most African power utilities have also failed to keep pace with the growth of their major cities.

Over the past 50 years, multilaterals, donors and national governments have set a variety of electrification targets, but the success stories have been few and far between. Rural electrification is cited as a major benefit of any new hydro or thermal power project yet they rarely achieve this objective. Power production from some schemes is often tied to new mining or other industrial projects, while some plants improve the reliability of supplies to existing customers rather than allowing new customers to be connected.

The simple explanation is a lack of money. African utilities lack the financial muscle to develop sufficient new generating capacity, while most Africans would be unable to pay anything like a commercial rate for electricity in any case. The Indian policy of vastly subsidizing power tariffs for the rural poor has not been popular in sub-Saharan Africa, even in countries that have sought to emulate India's agrarian socialism of the 1970s, such as Tanzania. Most utilities argue that there is simply not a large enough urban middle class to support such a policy.

Average GDP per capita in Africa is just over \$900, but most Africans generate far less, as the figures are skewed by South Africa, North Africa and the oil producers of the Gulf of Guinea. Average annual growth rates exceeded 5% from 2004-2008, but in its *African Economic Outlook 2009* the African Development Bank forecast this figure will fall to 2.8% this year. With population growth just over 2%, this is insufficient to affect per capita buying power. Moreover, much of the strong growth recorded in recent years was the result of high commodity revenues that often have little effect on the wealth of the general public.

Continental growth is expected to rebound to 4.5% in 2010. However, higher levels of growth must be sustained over a long period if they are both to persuade power

utilities significantly to extend their distribution networks and provide more potential customers with the means to pay for electricity. Far too many rural Africans are currently detached from the monetary economy. Enabling them to pay for electricity will require a socio-economic revolution that seems unlikely within the next generation.

Potential solutions

The poverty of much of sub-Saharan Africa reduces its ability to attract private sector investment in power projects. Since it took control of the national Gabonese power company Societe d'Electricite et d'Eaux in 1997, French firm Veolia, formerly known as Vivendi, has had some success in increasing urban electrification rates, but Gabon is relatively wealthy and few African markets could sustain a commercial approach.

Elsewhere, Chinese companies are building hydroelectric dams in a dozen countries, including Ethiopia and Ghana, but these are generally motivated by diplomatic offensives rather than investment ambition. By the same token, the Nigerian government has persuaded oil companies to develop gas-fired plants, but it has substantial leverage over such investors in the form of upstream oil concessions. Most countries do not have such a luxury, but again transmission and distribution infrastructure is still largely ignored as it does not provide the photo opportunities that donors, investors and politicians crave.

However, one of the biggest power companies in the world is promoting African electrification. South Africa's Eskom has the capacities of a developed country utility and has been tasked by Pretoria with extending access to power to the entire South African population. At the dawn of democracy in the country in 1994, just 36% of South Africans had access to electricity, including just 12% in rural areas. The overall figure passed 70% in 2005, with 52% for rural citizens. An average 300,000 households were connected each year from 1994-1999, and the rate remains high at about 250,000 a year. Pretoria has set a target of universal electrification by 2012.

One of the main tools employed in Eskom's rural electrification campaign was the pre-paid meter. Billing is a problem in many parts of Africa, where there is often neither a residential postal system nor formal addresses.

Electrification rates in Africa (%)

Tunisia	99	Nigeria	46	Madagascar	15
Algeria	98	Botswana	39	Angola	15
Egypt	98	Zimbabwe	34	Ethiopia	15
Libya	97	Namibia	34	Kenya	14
Mauritius	94	Senegal	33	Tanzania	11
Morocco	85	Sudan	30	Lesotho	11
South Africa	70	Benin	22	Uganda	9
Cote d'Ivoire	50	Eritrea	20	Malawi	7
Ghana	49	Congo	20	Burkina Faso	7
Gabon	48	Zambia	19	DR of Congo	6
Cameroon	47	Togo	17	Mozambique	6

Source: UNDP Human Development Report 2008 based on surveys from 2003-08. Includes only countries for which there is comprehensive data.

This problem gave rise to the 'pay as you go' model of mobile phone services and is now being replicated in the water and power sectors. Revenue collection rates have increased since meters were introduced, while new innovations reduced the cost of each connection from R4,500 in 1991 (\$561) to R2,800 by 2000.

Eskom invests \$400 million a year, or about 30% of its annual profits, in electrification. Most connections have been completed by Eskom itself, but the private sector has also been involved. One contractor, black empowerment firm Edison Power, plans to seek a listing on the Johannesburg Stock Exchange, partly in order to fund its expansion into the rest of Africa.

In a recent report on the process, Eskom said: "Some of the technical innovations were the development of a series of structures and conductor cable types that were readily available and allowed for easy construction at lower cost. This led to the development of a range of 'building blocks', which could be used to design and construct electrification projects as in a production line. It was also necessary to define the parameters by which networks were designed and match that to the load demanded by the inhabitants. It was estimated that these measures reduced the cost per connection by approximately 20%."

Eskom's strategy is now being replicated in other parts of Southern Africa. Mozambique's state power company Electricidade de Mocambique is undertaking an electrification program in the underdeveloped northern and central provinces. The country's 6% electrification rate is based on 2005 data, but EdM estimates that the figure had risen to 14% by June. A total of 340,000 homes have been connected during that period, with 90,000 new connections planned this year. Mozambique remains one of the poorest countries in the world, but average economic growth of 10% over the past decade, coupled with substantial donor support, is providing the government with the resources to invest in infrastructural projects.

However, energy minister Salvador Namburete concedes that the new customers will not generate profits. Speaking at the Electrification Initiative in Maputo in June, he said: "Because EdM is a state-owned company, and in order to guarantee electrification of the country, it gets its income from profitable areas, such as the south of the country, or from major industrial users of energy, and applies this money to finance electrification of unprofitable areas." He added: "Electrification must be undertaken because it induces development. It's also a way of reducing regional asymmetries so that, at some time in the future, people will be able to pay for the electricity they consume." This shows that government revenues from big business can benefit the bulk of the population, but only if there is the political will to do so.

Not only is this political will often lacking, but those funds that are directed towards the power sector are sometimes consumed by corruption. In May, two members of the Nigerian parliament were accused of

corruption regarding rural electrification contracts by the country's Economic and Financial Crimes Commission. What made the case particularly shocking was that the two men were responsible for investigating corruption in the Nigerian power sector.

Donor support

When politicians are serious about electrification, donor support can be crucial in funding projects. The EU seems increasingly prepared to finance electrification, including through its EU-Africa Energy Partnership. Speaking at an African power sector conference in Paris in June, Jean Lamy, the head of energy and climate at the French Ministry of Foreign and European Affairs, said: "Without energy, there is no development or effective fight against poverty. Whether the problem concerns rural electrification, infrastructure, or lack of energy in the towns, it prevents social and economic development."

However, more EU funding is given to the five North African states where most people already have access to electricity than to the countries that really need it. The scale of the problem is so great that massive donor funding would be required. The World Bank estimates that annual investment of \$31 billion over a period of ten years would be needed to provide universal electrification in Africa.

Other solutions mooted at the Paris conference focused heavily on renewables. Geothermal energy, which already provides 15% of Kenya's electricity, could be exploited along the Great Rift Valley from Ethiopia to Mozambique. It is highly reliable and does not require imported feedstock, but again the lack of transmission and distribution grids would remain a barrier.

Distributed generation

There is one potential solution to the absence of transmission and distribution infrastructure. African power sectors could leapfrog technologies. Attempts to extend fixed line telephone networks have been virtually abandoned in much of the continent because of the stunning success of mobile phones. In countries such as Tanzania and Zambia, ten times more people have mobiles than landline connections. Similarly, off-grid renewable energy projects could provide electricity using local resources, particularly in rural areas, without the need to fund transmission and distribution projects.

The cost of solar photovoltaic technology is falling and governments from East Asia to Southern Europe are encouraging investment in this area. While most of the African continent lacks substantial wind power resources, it does possess huge solar potential. Further technological advances and lower costs would be required to make solar power viable, but in the long term this could be the best option for rural electrification, although there can be no guarantees on future affordability.

A recent UN-sponsored study of the African power sector concluded that industry reforms over the past decade had failed because they focused on coping

Lessons from South Africa

Lessons from the experience of South African power utility Eskom in developing electrification programs:

- Electrification programs require strong government intervention at an early stage of development, especially when the overall energy economy is far from saturated.
- Electrification should not be evaluated only in terms of financial cost effectiveness, but also by considering access to electricity, socio-economic development and progress towards improved quality of life.
- Attempts should be made to use optimal technological and operational options in any electrification program to help reduce costs.
- Cost recovery of electrification programs should be strongly linked with affordability to the users.
- Realizing the full benefits of electrification may be slow and there is a need to look for ways to maximize benefits over both the shorter and longer terms.
- Modeling is a useful tool to develop options to manage load distribution and ensure optimal conditions for electrification.
- Demand side management can assist with the realization of benefits. It should, however, be linked to affordability, as the cost of implementation can be a barrier, as can physical access to the suggested measure. For such benefits to be realized and maximized, these programs should be closely monitored and verified.
- A centralized approach is required for planning.
- Customer knowledge is essential and both tariffs and technology must be matched to customer requirements.
- Standards must be based on proven pilots. Innovation is restricted to the pilot phase.
- Revenue collection is critical and must tie in to technology and culture.
- Non-grid options need to be integrated in a controlled manner.

with short-term generation problems and providing financial support to state-owned utilities. It concluded that they failed to create sustainable power sectors. As a result, rural electrification programs have not increased the proportion of people with access to electricity. The UN predicts that the number of Africans without access to electricity will increase from 550 million today to 650 million by 2030.

The experiences of Mozambique and South Africa show that power can be provided to rural inhabitants even in very poor areas, providing governments are prepared to adopt a long-term socio-economic outlook. A combination of good governance, donor support and prioritizing rural electrification demonstrates that improvements are possible. Yet while the profitable side of Eskom's business may be large enough to fund universal electrification, this is unlikely to be the case in Mozambique and most of the rest of the continent without power sector aid on the scale outlined by the UN.

Forthcoming conferences

Biogas Markets

July 1-2
London, UK
www.greenpowerconferences.com

GasAfrica-Nigeria 2009

July 7-9
Abuja, Nigeria
www.gasafrika-nigeria.com

Renewables 2009

July 8-9
London, United Kingdom
www.marketforce.eu.com/renewables

EIC Energy Congress

July 8-10
Medellin, Colombia
www.eiccongress.com

GreenPower's 5th BioPower Generation

July 8-9
Chicago, USA
www.greenpower.msgfocus.com

3rd Annual Western Transmission Conference

July 13-14
San Francisco, USA
www.euci.com/conferences

20th World Oil Forum

July 13-15
London, UK
www.petro21.com

Sub-Saharan Africa Oil and Gas Conference

July 28-29
Houston, USA
www.energycorporateafrica.com

Commercializing FLNG Asia 2009

July 28-30
Singapore
www.iqpc.com.sg

Oil and Gas Outlook Africa 2009

July 28-31
Cape Town, South Africa
www.terrapinn.com

Energy and Sustainability 2009

August 9-12
Newark, USA
www.conference.solarigert.org

4th Annual LNG

August 10-11
Perth, Australia
www.marcusevans.com

3rd Renewable Energy India 2009 Expo

August 10-12
New Delhi, India
www.renewableenergyindiaexpo.com

Smart Grid Implementation Summit

August 17-19
Washington, US
www.iqpc.com

Sustainable Energy Technology 2009

August 31-September 3
Aachen, Germany
www.set2009.org

Bioenergy 2009

August 31-September 4
Jyväskylä, Finland
www.bioenergy2009.finbioenergy.fi

CISBAT 2009

September 2-3
Lausanne, Switzerland
www.cisbat.epfl.ch

2nd Nordic Wood Biorefinery Conference

September 2-4
Helsinki, Finland
www.kcl.fi/nwbc-2009

Latin American Wind Power

September 2-4
Panama City, Panama
www.windexpo.org

IAEE Energy, Policies & Technologies for Sustainable Economies

September 7-10
Vienna, Austria
www.iaee.org

Power and Energy Systems

September 7-9
Palma de Mallorca, Spain
www.iasted.org

South East Asia Australia Offshore

September 9
Darwin, Australia
www.seaaoc.com

Platts 3rd Annual European Refining Markets

September 14-15
Brussels, Belgium
www.platts.com

2nd Annual Carbon Capture and Sequestration

September 14-15
Washington DC, USA
www.platts.com

2009 Transmission Planning and Development Forum

September 14-15
Arlington, USA
www.platts.com

Gas Infrastructure World, Caspian 2009

September 14-16
Baku, Azerbaijan
www.terrapinn.com

Offshore Wind 2009

September 14-16
Stockholm, Sweden
www.ewea.org

World Bioenergy**– Clean Vehicles & Fuels 2009**

September 16-18
Stockholm, Sweden
www.elmia.se/en/wbcvf/
European Smart Grid Strategies
September 17-18
Berlin, Germany
www.platts.com

24th European Photovoltaic Solar Energy Conference

September 21-25
Hamburg, Germany
www.phtovoltaic-conference.com

Energofutura 2009

September 23-24
Bratislava, Slovak Republic
www.energofutura.com

Russian Coal Markets Conference 2009

September 23-24
St Petersburg, Russia
www.mccloskeycoal.com

4th Annual Pipeline Development and Expansion

September 24-25
Houston, USA
www.platts.com

Energy from Waste

September 28-29
London, UK
www.smi-online.co.uk

10th Annual FPSO Congress 2009

September 29-30
Singapore
www.iqpc.com.sg

Unconventional Gas International Conference and Exhibition

September 29-October 1
Fort Worth, USA
www.unconventionalgas.net

32nd Annual Coal Marketing Days

October 1-2
Pittsburgh, USA
www.platts.com

2009 Gasification Technologies Conference

October 4-7
Colorado Springs, USA
www.gasification.org

24th World Gas Conference

October 5-9
Buenos Aires, Argentina
www.wgc2009.com

CCS Summit 2009 – Getting it right for Copenhagen

October 6
Brussels, Belgium
www.ccsconference.eu

LETTER FROM ERBIL: JUNE 2009

Where there's a Kurd there's a way

As the Austrian Airlines flight from Vienna comes to a halt on the runway at Erbil airport, it is hard to believe this is Iraq. Why are there so many people of European ancestry on this three-quarter full flight? When do we get issued with body armor? Where is the security?

After disembarking it is quickly apparent that Erbil, capital of Iraqi Kurdistan, is nothing like the Iraq portrayed in the media. Indeed, security is almost non-existent and completely unobtrusive. Instead of bombproof cars and checkpoint after checkpoint, at Erbil, you clear customs and grab a taxi to your hotel without fuss. Even the hotel, a potential target for hostile elements looking to discourage a foreign presence, is relatively blasé about security with a couple of concrete blocks on the edge of the road's curb and a metal detector that looks like it would fall apart if a gust of wind hit it. With the exception of the odd soldier on a street corner or outside a government building, this is clearly a city comfortable in the skin of its newfound stability.

And not just comfortable, but proud. "Since March 2003 (the start of the US-led invasion of the country) not a single coalition soldier has died nor a single foreigner been kidnapped in the areas administered by the KRG," the Kurdistan Regional Government asserts on its website. It is with this same pride that on June 1 the KRG played host to guests from some 40 countries at a ceremony to celebrate the start up of exports from its Tawke and Taq Taq oil fields. Among those in attendance were Iraqi President Jalal Talabani, a Kurd, Kurdistan President Masoud Barzani, KRG Prime Minister Nechirvan Barzani and KRG minister for natural resources Ashti Hawrami. Also present were DNO chief executive Helge Eide, Genel Enerji boss Mehmet Sepil and Addax CEO Jean Claude Gandur, the oil companies responsible for the fields' development.

Exports were initially set to flow at a rate of 100,000 b/d, rising to 250,000 b/d within a year. "Today is a special day for the whole of Kurdistan and indeed all of Iraq, for the first time in Iraq's history, the people of Kurdistan are making decisions on the natural resources of the region," Hawrami said in an address to the audience. "Now oil can be a blessing for our people and a source of prosperity and stability," he added. "Today we are a successful example for the rest of Iraq, today we showed that market-driven policies and conviction can lay the foundations for a better Iraq," he said at the celebrations, which ended with a folk dance depicting the various stages of bread making.

The significance of the occasion was not lost on those present; this was, after all, the first instance of a foreign company exporting Iraqi oil since the country nationalized the industry in the 1970s. While the Kurdish government acknowledges the role the federal government played in the exports going ahead – oil is being transferred from the two fields to the Turkish Mediterranean port of Ceyhan through Iraq's northern pipeline, requiring the federal government's approval – it also took the opportunity to throw some jabs at Baghdad policy and delays in passing a national hydrocarbon law. "If federal oil policies are not changed to increase exports to boost revenue and if a fair and transparent revenue sharing law is not enacted soon the consequences will be very serious," Hawrami said. "Indeed, the security, unity, the future of our country depends on this."

However, the KRG is not without problems of its own. The federal government still considers agreements signed by the KRG with International Oil Companies to be illegal and while it has allowed the Tawke and Taq Taq fields to tie into the northern pipeline, these two contracts were signed before the country approved its constitution and have thus been granted special status. It remains to be seen what happens when other fields – there are already 30 companies operating in the region – come on-stream.

Another factor is how the companies involved in the new exports are going to be paid. At the time of start-up no agreement had been reached on remuneration, although both the KRG and the companies involved have expressed confidence a resolution was imminent. "The issue of the payment of the companies will be dealt with through a mechanism after the exports start... The moment it starts a mechanism will be put in place and we are confident because of our positive contribution that it will be sorted out quite soon," said KRG senior adviser to the prime minister Khaled Salih.

"No company will work for free," said DNO's Eide. "I think you should also remember there are also quite a lot of oil companies now starting to invest in the region . . . and potentially investing in the rest of Iraq, so I think it will be important to find a solution . . . I think it is important to the region and important to the country to find a solution to this as quickly as possible," he said.

The KRG has not released the payment agreements issued in their production sharing contracts, but has hinted it may be around 10-12% of revenues. Under the country's revenue sharing laws, Kurdistan is entitled to 17% of oil revenues. Having set itself a target of producing 4 million b/d of oil within two years and between 6 and 8 million b/d by 2013, the central government could do worse than try to reach some sort of agreement with the KRG on oil output, especially given the failure of Baghdad to finalize an oil law and with production levels still below those at the end of the Hussein-regime. "In recent years, the Kurdistan Region has been rebuilding and developing, economically and politically, through practical compromises," said KRG prime minister Barzani. "We hope to see the same spirit of negotiation throughout Iraq."

Geoff King

LETTER FROM WASHINGTON: JUNE 2009

Costing the cap-and-trade scheme

Who pays the price of reducing greenhouse gas emissions is a difficult question since the benefits in terms of hard-to-quantify environmental consequences are global. But before these probably immeasurable goodies (in both senses) can be captured, there is a real financial cost to be borne at home. Various stakeholders are concerned that they will bear more than their fair share of the upfront costs, and the only model available for comparison is the EU Emissions Trading Scheme, where there have been unintended winners and losers.

In the US, various studies are being done to highlight where the costs of the proposed cap-and-trade scheme might fall. According to one by the not-for-profit Investor Responsibility Research Center Institute and environmental data and analysis firm Trucost, electric utilities would be the most financially exposed. "If the 34 utilities analyzed in the study were to pay for each metric ton of emissions, carbon costs could reduce their combined earnings by 45%," the study says. "If a market price of \$28.241 were applied to each ton of CO₂ [equivalent] emitted by companies in the S&P 500 and their first-tier suppliers, carbon costs would total over \$92.8 billion." According to the study, the chemical, oil and gas sector would be the fourth most-affected group.

However, financial risk would vary widely. "Earnings could fall between less than 1% and 117% by company, if carbon costs were incurred. Carbon costs would amount to less than 1% of earnings for 203 companies analyzed, while 71 companies could see earnings fall by 10% or more," the study said. According to Jon Lukomnik, program director of the IRRIC Institute, "the analysis makes clear that a cap-and-trade system is a real game changer. A number of companies will have to reform how they think about carbon emissions and the associated costs, or their bottom line will suffer greatly."

From the government's point of view, it needs to persuade conservative legislators that the scheme raises as much as it costs. An analysis by the US Congressional Budget Office estimates that the cap-and-trade program in the climate and energy bill approved by the House of Representatives Energy and Commerce Committee would raise about \$858 billion between 2010 and 2019 for the federal government.

The CBO and the Joint Committee on Taxation estimates that the bill would raise that amount through the auction of tradable allowances for GHGs and hydrofluorocarbons and the free distribution of a certain percentage of the GHG allowances. The CBO estimates that the price of GHG emission allowances under the program would start at \$15 per metric ton of emissions in 2011 and increase to about \$26/mt CO₂e in 2019. However, the overall bill would also require an increase in direct spending by the federal government of \$821 billion in the same period, providing a net benefit to the government of about \$37 billion.

However, critics of the bill have questioned the CBO's forecast, saying the agency used too low an estimate for the cost of carbon allowances per ton. In addition, they said the bill's provisions for carbon offsets may result in too few of these projects emerging to mitigate the costs for industries that must reduce their emissions. "The CBO's cost assessment may be fundamentally flawed," said Scott Segal, a partner at the Bracewell & Giuliani law firm. Despite the fact that carbon allowance auctions will raise money for the federal government, CBO "is still clear that the bill has tremendous costs associated with it," said Segal. "This should give fiscal conservatives real pause."

The CBO's forecasts of both expenditure and revenue inevitably contain huge uncertainties as does the analysis of the impact of the scheme on company revenue. A critical factor is the market price of CO₂ emissions allowances. This could prove volatile, if the European experience is anything to go by. In the first phase of the EU ETS, the price of carbon allowances sank to zero, when it became clear that the European Commission had over allocated. In the second phase, they again dropped sharply as recession bit, although they have since staged something of a recovery.

And there have been unintended winners and losers – notably utility revenues do not appear to have suffered much as yet, while the oil and gas industry appears likely to emerge with windfall profits, a development which perhaps the US oil and gas industry should note.

According to Sam Gomersall of carbon capture and storage project developer CO₂DeepStore, the UK government allocated carbon credits to oil and gas producers for the period 2008-2012 based on emissions produced by the industry from 2000-2004. In 2003, offshore oil and gas emissions totaled 21.9 million tons. That figure is expected to drop to less than 10 million tons by 2012 as oil and gas production falls. Based on a conservative estimate of €15/mt (\$20.83/mt) of CO₂ emitted, oil and gas producers will benefit from windfall revenue of £430 million (\$692 million) in phase two of the EU ETS.

The EU experience suggests that the real costs of the ETS have not really yet been faced and the US variant will also take time, owing to the large-scale give-away of allowances in its initial phases. When the crunch does take place, the financial burden is likely to depend on companies' ability to pass those costs on to consumers, which will depend heavily on the type of market in which they operate. In the meantime, free carbon allowances provide a potentially profitable trading opportunity with little downside.

Washington Staff

LETTER FROM MOSCOW: JUNE 2009

Re-routing Russia's crude

While recent disputes between Ukraine and Russia have focused on gas, Russia is also reliant on both Ukraine and Belarus for the transit of crude. This is a reliance which it intends to end, in part by sending more tankers through the Baltic Sea. Russia's national oil pipeline operator Transneft in June officially launched construction of the new Baltic Pipeline System-2, which will take Russian crude to the Baltic Sea coast without crossing Ukraine or Belarus. According to Russian Deputy Prime Minister Igor Sechin, "the project is within Russia's policy to diversify Russian export routes and strengthen our energy security."

Transneft President Nikolai Tokarev estimated that the two-phase project will cost Rb130 billion (\$4.18 billion). The first phase involves construction of a 998 kilometer pipeline that will transport 30 million mt/year (600,000 b/d) of crude from the Druzhba pipeline at Unecha to a loading terminal in Ust-Luga on the Baltic Coast. It will also include the construction of two pumping stations and modernization of the existing two, as well as a new oil export terminal in Ust-Luga. It is expected to be completed in third-quarter 2012.

A second phase would expand the pipeline's capacity to 50 million mt/year, (1,000,000 b/d), add four more pumping stations and construct a 172 km offshoot to the Kirishi refinery. "We will be able to expand the capacity quickly, as soon as we see the need to do so," Sechin said when asked about the timing of stage two. Transneft and Russia's fourth-largest oil producer Surgutneftegaz, which owns the Kirishi refinery, plan jointly to build the 12 million mt/year offshoot.

Surgutneftegaz is also considering the construction of a new refining facility near its 22 million mt/yr (440,000 b/d) plant at Kirishi. Surgutneftegaz previously said it would make the decision to proceed with the Kirishi-2 project after the decision on the offshoot is made by the government. Sechin said the project would help meet demand for oil products in the entire north-western region of Russia.

Russia is also thought to be near completion of the first section of the East Siberia-Pacific Ocean oil pipeline, which is designed to take crude oil from East Siberian fields to the Pacific Ocean, but also includes a 300,000 b/d off-shoot into China. The first stage of ESPO will have capacity of 600,000 b/d, while a second stage will see capacity rise to 1.6 million b/d. For the moment, crude will be taken on the final leg of the journey by railroad to the Pacific Ocean port of Kozmino for export. A 400,000 b/d refinery is also planned near Kozmino, coming on-stream in two stages, the first in 2013 and the second in 2017.

And, if that was not enough, there are also plans to start construction of the Burgas-Alexandroupolis pipeline in 2010. This project, which has been under discussion for some 15 years, would ship oil from the Russian port of Novorossiisk across the Black Sea to Burgas in Bulgaria and then pipe it to Alexandroupolis, on the Aegean Sea. The pipeline would have initial capacity of 700,000 b/d and might be expanded to 1 million b/d after 2016. It is designed to reduce the cost and time of transporting Russian oil from the Black Sea via the crowded Bosphorus Straits, but would also replace Black Sea exports of Russian crude from Ukraine.

But where will the crude come from to fill these new pipelines? Under the economic development ministry's basic scenario, Russian crude output will rise to 10 million b/d in 2010, an increase of just 200,000 b/d from 2008, stabilize at this level until 2020 and then decrease to 9.8 million b/d by 2030. Crude exports would amount to 5.12 million b/d in 2010, falling to 4.9 million b/d by 2030. It appears that the new pipelines are all about re-routing Russian crude, reducing dependence on transit countries and increasing access to markets.

Odessa-Brody threatens Druzhba

Sechin did not rule out the possibility that Ukraine's plan to redirect supplies via the Odessa-Brody pipeline, which currently operates in reverse mode towards the Black Sea port of Odessa, might block Russian crude flows via the Druzhba pipeline. Druzhba is the key inland route for Russian crude exports to Europe.

"Implementation of Ukraine's plans regarding Odessa-Brody . . . may lead to a shut-in of the southern branch of Druzhba," Sechin said, referring to the pipeline branch running to Hungary and Slovakia via Ukraine. "If the flow starts from Odessa to Brody to [the Polish city of] Plock – and they also want to [extend it to] Gdansk – this might shut in our northern branch as well," he said referring to the Druzhba line running via Belarus to Poland.

Ukraine has recently intensified work to start moving Caspian Sea oil via Odessa-Brody to Europe, replacing supplies of Russian oil. The EU has supported this to relieve concerns that some of its members, such as Poland, Slovakia and Lithuania, depend too much on Russian oil. Russia currently exports 80,000 b/d via Ukraine's port of Odessa and 200,000 b/d via the port of Yuzhny near Odessa.

A further 100,000 b/d of Russian oil is exported via Gdansk in Poland. These volumes could be redirected to BPS-2, Tokarev said. In addition, Russia's existing BPS-1 system currently operates at rates exceeding its throughput capacity, which will also allow the redirection of some of the crude to BPS-2. Sechin also said that Kazakhstan might send some of its Russia-bound crude via BPS-2. Kazakhstan and Russia are in talks to raise Kazakhstan's crude transit via Russia by 200,000 b/d from the current level of 420,000 b/d.

Nadia Rodova

LETTER FROM BRUSSELS: JUNE 2009

EU agrees monthly oil stocks, nuclear safety

EU energy ministers reached an informal political agreement on the European Commission's proposals to strengthen EU oil stock rules at an EU Energy Council meeting in Luxembourg on June 12. The Commission last proposed changes to the oil stocks regime in September 2002, but had to withdraw its proposals in October 2004 when national governments rejected them. Oil almost hitting \$150 obviously makes a difference, but apparently not that much of one. The Commission failed to persuade EU members to publish weekly aggregated commercial oil stock levels. Instead, the ministers agreed to publish such data monthly.

The Commission proposed the new EU oil stocks directive last November as part of a wider energy security package to strengthen the EU's ability to handle energy supply problems. An EU council source, who followed the ministers' debate, said that all national governments had opposed weekly reporting, arguing that it would be too difficult to process the data accurately in such a short time. US statisticians are clearly superior to their European counterparts as they manage the task on a weekly basis – or perhaps the data isn't accurate.

The Commission already publishes the level of strategic stocks held by each EU country, but not additional commercial oil stocks. It had hoped to publish this commercial data on a weekly basis to improve transparency and limit the effects of "uninformed speculation," although the informed type is probably just as dangerous.

EU energy commissioner Andris Piebalgs told reporters after the meeting that he was disappointed the weekly data publication was not agreed. "I deeply regret that we have not adopted it," he said. "In my opinion it was necessary and good for the market." However, ministers did agree to include a clause which gives the Commission the option to propose weekly reporting again without having to propose an entirely new directive. The proposal would have to be approved by a committee of national experts, a process known as comitology.

Piebalgs said the new rules were still an improvement. They require EU countries to maintain total oil stocks of at least 90 days of average net imports or 61 days of average daily consumption, whichever is the greater. A third of this must be refined products.

The ministers said in their meeting conclusions that: "Oil stocks can be held at any location across the EU as long as they are physically accessible and fully available. They can also be held in another [EU country's] territory, if agreed by the [EU country] on whose behalf the stocks are being kept." EU countries "must have contingency plans and efficient procedures to release stocks rapidly and transparently in a crisis situation," they said. "In addition, monitoring will be strengthened. [They] must keep a detailed register of their emergency stocks and allow them to be verified at any time."

Piebalgs said the new rules would mean that the EU would be better prepared for a crisis. "We don't think we are in big danger, but it is better to be well prepared," he said. "We now have an efficient mechanism in place for sufficient stocks. The Commission will monitor the availability of stocks and the mobilizing of [them]." The ministers' agreement is to be rubber-stamped at a later EU Council meeting after being checked by legal linguists, the EU Council press service said. EU countries have until December 31, 2012 to transpose the decision into national law, unless they are not currently IEA members, in which case they have two extra years.

EU's first nuclear safety law agreed

Another Commission proposal which has finally gained enough national government support to be adopted is the EU nuclear safety directive. EU ministers are set to rubber-stamp the new directive in the next few months after EU diplomats agreed a draft text at a meeting on June 10-11, according to an EU Council source.

The directive is the EU's first legally binding legislation on nuclear installation safety, an area that national governments have resisted letting the EU regulate. "The draft text was agreed without debate [by the diplomats]," said the source. "It will be adopted by a future EU council, but we don't know exactly when yet – it has to be translated and checked by legal linguists first, which can take some months."

The safety directive has been under discussion since 2003, but an initial version prepared by the Commission was rejected by EU ministers, acting in the EU Council, in 2004. After much consultation, the Commission proposed a revised version last fall. The Czechs, who hold the rotating EU presidency until the end of June, had pushed to get an agreement during their presidency.

As now drafted, the directive is milder than some would have liked, but that ensured its acceptance by all 27 EU states, industry sources said. Dana Drabova, head of the Czech State Office of Nuclear Safety, had told the European Commission's fourth European Nuclear Energy Forum in Prague May 29 that approval was imminent.

Drabova, who also holds the revolving chair of the Western European Nuclear Regulators' Association, said "a growing social demand for stable, reliable [international] safety requirements" was the impetus for the EU safety directive. She said that demand convinced the once-skeptical Czechs to support EU-level oversight over the safety of national nuclear programs, the policy turnaround perhaps a result of the revolving chair.

Siobhan Hall

2010 oil demand: expansion or contraction?

At its last meeting, OPEC reaffirmed its commitment to existing output targets. However, instead of falling, OPEC-11 production jumped by 250,000 b/d in May, following a rise of 130,000 b/d in April, the first rise in output since August last year. Iraq, which is not governed by the output targets, added 50,000 b/d in May. This means that OPEC-11 pumped an estimated 25.990 million b/d, 1.145 million b/d above its declared target.

The rise in output was broadly spread; Angola (+40,000 b/d), Iran (+50,000 b/d), Nigeria (+90,000 b/d), Qatar (+10,000 b/d), Saudi Arabia (+60,000 b/d) and the UAE (+20,000 b/d). Only Venezuela reduced production (-20,000 b/d), most likely reflecting operational limitations. Having spent months reigning in supply, almost all OPEC countries have surplus capacity that can be brought quickly on-stream. Owing to the drop in revenues, it is also financially expedient.

OPEC output remains in line with the expected call on OPEC through 2009. The International Energy Agency, in its June oil report, puts the 2009 call at 27.7 million b/d, the US Energy Information Administration estimates it at 28.5 million b/d and OPEC itself at 28.6 million b/d. This would suggest that crude stocks should remain fairly steady at current high levels.

The declining trend in forecasts for demand this year also appears to have bottomed out. The message is that the demand situation has stopped getting worse, and, while still bad, might now start to improve. Neither OPEC nor the IEA have yet said how they see demand evolving in 2010. The EIA makes what looks like a bullish estimate of demand growth of 700,000 b/d, but not all forecasters are convinced. KBC Market Services sees demand being flat, although in May it predicted a 300,000 b/d drop. The IEA and OPEC should make their predictions for 2010 in their July oil reports.

A signal that the market remains weak, despite the rise in oil prices is the reaction of refiners. US refiner Valero said in June that it would shut its 235,000 b/d Aruba refinery for two to three months, owing to poor margins. It is also taking the opportunity for maintenance at its 20,000 b/d coker in Corpus Christi. Japan's oil products exports in the first four months of 2009 were down nearly 2% on the year. Double-digit falls are expected in the second quarter amid deteriorating profit margins, suggesting that Japanese oil products exports might see a year-on-year decrease in volume this year for the first time since 2003. Refinery run rates are currently averaging around 72-73% and are expected to remain at such levels until early July at least.

In the US, at the start of June, crude oil stocks had fallen slightly, but at 362 million barrels were still 59 million barrels higher than at the same point last year. But the overhang is much more evident in oil products, where at 739 million barrels, inventories were 73 million barrels higher than in June 2008. US stocks of gasoline are relatively low, running just below last year's level, but the amount of intermediate stocks in the 'other oils' category of the EIA's inventory data may hide a significant number of barrels that could find their way into the gasoline supply pool.

As a result, low refinery margins and high inventory levels for all refined products except gasoline suggest that the weakness of demand is better illustrated in the products market than in crude. In the latter, prices reflect future expectations rather than current physical market conditions. A key factor will be how the forecasters see demand in 2010; will they go with the bullish EIA position of a speedy recovery, or plump for the more pessimistic scenario in which demand continues to contract?

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

Country	May	April	March	February	January	December	New target January 1, 2009*
Algeria	1.250	1.250	1.260	1.260	1.320	1.340	1.200
Angola	1.740	1.700	1.690	1.700	1.820	1.880	1.506
Ecuador	0.470	0.470	0.480	0.480	0.490	0.500	0.429
Iran	3.750	3.700	3.650	3.650	3.700	3.840	3.334
Kuwait	2.250	2.250	2.200	2.230	2.330	2.460	2.221
Libya	1.540	1.540	1.550	1.550	1.640	1.670	1.472
Nigeria	1.800	1.710	1.690	1.720	1.880	1.940	1.704
Qatar	0.760	0.750	0.750	0.750	0.780	0.810	0.730
Saudi Arabia	8.010	7.950	7.900	7.930	8.030	8.370	8.014
UAE	2.240	2.220	2.240	2.250	2.300	2.380	2.226
Venezuela	2.180	2.200	2.200	2.200	2.250	2.320	2.010
OPEC-11	25.990	25.740	25.610	25.720	26.540	27.510	24.846
Iraq	2.400	2.350	2.370	2.350	2.430	2.390	NA
Total	28.390	28.090	27.980	28.070	28.970	29.900	24.846

*OPEC did not publish individual allocations under the 24.845 million b/d target total. These figures are calculated by Platts.

Source: Platts

Venezuelan nationalizations motivated by debt

Venezuelan state oil company PDVSA is moving to nationalize at least some drilling rigs owned by foreign, mostly US-based, companies, despite protestations to the contrary, according to Venezuelan oil industry and PDVSA sources. PDVSA President and Energy and Oil Minister Rafael Ramirez told reporters in June that drilling rig companies need not be nationalized. Ramirez said about 50 companies are providing some of the 151 rigs currently active in the country. If PDVSA couldn't get a deal with one, the oil company would be happy to seek another contractor instead, he said.

However, on June 8, Dallas-based rig contractor ENSCO said that its ENSCO 69 drilling rig, its only rig in Venezuela, had been seized by PDVSA, that PDVSA workers were operating it and that the company was abandoning both rig and country. Besides ENSCO, two other US rig contractors are also thought to have had some or all of their rigs effectively nationalized.

One foreign oil executive working in a joint-venture with PDVSA, said nationalizations, overt and covert, will continue as long as that policy favors the national oil company financially. "My fear is that they will nationalize anything that helps them avoid debts, which means individual rigs will be included. They can't nationalize ENSCO, but they can take over the local rig so that ENSCO can't stop working because of unpaid invoices."

"PDVSA has not paid anything since August 2008 to service companies and since the end of 2007 to foreign investors" in the *empresas mixtas* (joint ventures with PDVSA), the executive said. "I don't think anyone expects to collect these funds anytime soon. PDVSA originally said they were trying to negotiate with the service companies to cut costs by 40%, but I think that is a smoke screen. They have no excuse for not paying the *empresa mixta* dividends except incompetence and lack of cash. And the companies being nationalized have

been promised book value in bonds or cash as compensation...I expect that will all go to arbitration."

PDVSA seems to be trading overt nationalization for a more covert kind, in the view of the foreign oil executive, and national pride has taken a back seat to financial considerations. "Yes, this is certainly creeping nationalization, but I think it is financially driven this time rather than politically driven. They are nationalizing companies in order to avoid paying their debts, so that they can maintain social spending," he said.

Nationalizations in disguise or not, the climate for foreign oil companies in Venezuela is not pleasant, the executive said. "I think most companies are very uncomfortable working in Venezuela in this environment. The large companies like Chevron will stay and continue to show interest, but there is no way they will invest substantial money here given what is happening."

That does not bode well for PDVSA's attempts to land new partners in billion-dollar oil projects in the Orinoco heavy oil belt through the offering of new E&P licenses, a process which began last year. "This means the Carabobo auction is dead and will have to be a direct award to a national company in China," is how the executive described it. "Everyone else is just waiting for the long-term situation to change and for contract law to be respected again."

One PDVSA official that spoke in condition of anonymity says that the truth lies somewhere between Ramirez's statements and the oil executive's assessment. "Something is being paid, but it's very little in comparison to what is owed. Besides, only those with pull (undue influence) are collecting." However, the official agreed with the assessment that PDVSA may still be experiencing a cash shortage, despite the recent rise in oil prices, and that shortage may mean some drilling rigs are effectively nationalized.

Militants step up Niger Delta attacks

Oil exporter Nigeria has been unable to take advantage of higher crude prices as attacks by militants in the Niger Delta have cut the country's oil output to less than two-thirds of its nominal 3 million b/d capacity. Nigeria's main militant group, the Movement for the Emancipation of the Niger Delta, said June 21 that it had attacked Shell pipelines at Adamakiri and Kula, both in Rivers state in the eastern Niger Delta. It also said it had attacked the Afremo offshore oilfields, which it believed were operated by Shell, and which it said were 14 miles from the Forcados export terminal.

Shell said earlier that some oil production had been halted following an attack on the Trans Ramos pipeline at Aghoro-2 in Bayelsa. The damaged pipeline supplies crude to the Forcados terminal. The company had already declared force majeure on Forcados oil loadings for June and July, owing to previous damage to another major trunk line in the Chanomi Creek area of Delta state. Italy's Eni reported earlier that a pipeline attack in

Bayelsa had halted 33,000 b/d of oil output and 2 million cubic meters/day of gas. Chevron was forced to halt 100,000 b/d of production after a militant attack on a pipeline it operates in the Abiteye area of Delta State.

According to a senior union official, the attacks have brought the total volume of lost production up to 1.3 million b/d. "A total of 1.3 million b/d has been lost. This is a lot of oil and will have a serious impact on our revenues," said Bayo Olowoshile, general secretary of the Pengassan union. While oil companies operating in the Niger Delta refused to comment on security issues, Olowoshile said that critical staff are being kept on installations to avoid more supply disruptions.

Militants have led a campaign of sabotage in the Niger Delta since early 2006 to push demands for greater control of oil revenues. MEND warned oil companies in May to evacuate their staff or face attacks, and called on its fighters to unleash what it called a horrible toll on the oil industry.

Peruvian protests target oil and gas infrastructure

At least 31 people were killed in a 24-hour period in northern Peru in early June, when police clashed with Amazon Indians over land rights in the rainforest, government officials reported. According to Prime Minister Yehude Simon, 22 police officers and nine civilians were killed after police forcibly re-opened a regional highway that thousands of Amazon Indian protesters had been blocking for days.

The clashes mark the bloodiest unrest in Peru since the Shining Path, a violent Maoist rebel group, terrorized the country in the 1980s and 1990s in its battle against the government. Simon warned that the civilian death toll was likely to rise, and local press reports said there could be up to 25 civilians dead. 108 civilians were thought to have been wounded.

The protests, which started in April, targeted oil and gas infrastructure and succeeding in shutting down crude oil pipelines, leading to warnings of fuel shortages. Officials with state-owned refiner Petroperu started to warn of possible fuel shortages in early June, although neither oil nor gas production appeared to have been affected in May.

The Argentina-based oil company Pluspetrol was forced to suspend operations at its oil block 1AB in the northern Peruvian Amazon in mid-May. Protesters took over pumping stations on a pipeline owned by Petroperu that typically carried up to 30,000 b/d from two fields in the area, including block 1AB.

Nearly 200 members of the Machiguenga people targeted the 328,120 Mcfd Camisea natural gas pipeline. Owned by TGP, the Camisea line carries gas from the Camisea fields to Lima. However, the pipeline was not reported to have been shutdown. The Camisea

area and its pipelines are responsible for delivering 25% of the total energy consumed in Peru. Peruvian police, backed up by the army, later managed to retake control.

The Peruvian Navy was forced for a second time in May to clear barricades built by native groups to prevent access to a crude oil development area operated by French company Perenco. The Native groups had set up river barricades, but offered no resistance to the military move to end the blockade. The Napo-Curaray River is the only non-air access to Perenco's Block 67, in the northeastern tip of Peru. The block is estimated to contain fields that together hold over 300 million barrels of crude oil. Production could rise to as much as 100,000 b/d of heavy, sour crude within a few years.

The protesters wanted to overturn decrees signed by President Alan Garcia easing restrictions on mining, oil drilling, wood harvesting and farming in the Amazon rainforest. They appear to have had some success as Peruvian lawmakers on June 10 suspended one of the controversial laws that eased restrictions on lumber harvesting, just days after the clashes between police and indigenous protesters.

The legislature agreed by a 59 to 49 vote to suspend Decree 1090 – dubbed the “Law of the Jungle” – that covers forestry and fauna in Peru's northeastern Amazon rain forest, said Javier Velasquez, the head of Peru's single-chamber Congress. A decree related to governing private investment was also suspended. Both measures are among decrees issued in 2007 and 2008 by Garcia, when Congress granted him special powers to implement a free-trade agreement with the US. The vote suspending the decree may allow the government to resume talks with the protesters.

PEMEX promises return to 3 million b/d output

Mexican state oil company PEMEX aims to return crude production to 3 million b/d of crude in the medium term, according to Director-General Jesus Reyes Heróles. PEMEX last produced 3 million b/d in September 2007. Since then, output has dwindled to 2.66 million b/d. Reyes Heróles was addressing the Mexican International Petroleum Congress in the Gulf port of Veracruz in June. He offered no timeline for achieving the 3 million b/d, nor where the increased output would come from.

PEMEX is already spending billions of dollars on drilling in the Chicotepec basin in the states of Veracruz and Puebla, although so far results have been meager. It is also spending heavily on prolonging the life of the once giant Cantarell field and further developing Ku Maloob Zaap (KMZ). Both complexes are located in the Sound of Campeche. Output from Cantarell is now down to less than 770,000 b/d from a peak five years ago of 2.2 million b/d. KMZ currently leads Mexican production with some 810,000 b/d.

Reyes Heróles added that PEMEX aims to reduce imports of petroleum products from 40% of the country's consumption at present to 22% by 2017, as a new

refinery is built and others updated. Reyes Heróles also unveiled plans for a new look PEMEX under a restructuring still to be approved by the company board.

He said that it would build on the energy reform passed by Congress last year. However, the scope of the reform is narrow, and Reyes Heróles repeated many of his buzzwords and those of his predecessors; PEMEX would increase transparency and accountability, he said, and opt for results-oriented management.

Much more emphasis would be placed, he said, on the front-end loading of project management to ensure clarity on costs, deadlines and evaluations of progress. PEMEX has a long history of shaky project management that has locked it into several multi-million lawsuits and left it with major investments that have failed to achieve their potential.

Where the reform would bring advantages would be in granting PEMEX autonomy for the purposes of its budget and financial management, both previously subject to approval by Congress. “That will give us the ability to draw up a business plan that sets realistic targets based on performance,” he said.

Estonia looks to oil shale technology exports

Just as Ireland is among the few countries to burn peat for power, the small Baltic state of Estonia is the centre of the world's oil shale industry. Developed out of necessity, oil shale is the country's only significant energy resource and thus central to its energy security.

However, while Ireland's peat has only limited application elsewhere, Estonia finds itself with unique long-term experience in a potentially major unconventional oil resource. But it is one which goes against the grain of current environmental thinking. Producing either oil or power from oil shale is a highly carbon intensive process.

The cost of emissions is proving a major factor in whether Estonia goes ahead with plans to develop further its oil shale industry. The country's state power company Eesti Energia says it may build two new oil shale-fired power units with a combined capacity of up to 800 MW at its Narva power complex in the east of the country as part of a major investment in a new oil shale energy complex. The total investment is expected to cost about Kroon 3 billion (\$268 million).

The new units could replace up to 1,600 MW of the current 2,000 MW of capacity at the company's two Narva power plants – Eesti and Balti – which if not upgraded would need to be decommissioned in 2016. The two plants currently produce around 90% of Estonia's total power output.

The company's supervisory board has approved a decision to tender for up to two new oil shale-fired power units with circulating fluidized bed boilers. A final investment decision will be made after the procurement process, which is expected to be complete by end-2010.

"There is a possibility that it will not happen. Emissions are something we are concerned about, but after considering all issues, it seems that [construction of oil shale-fired capacity] is the most realistic and competitive solution, but we are quite cautious on taking the final steps," said Jaanus Arukaevu, director of strategy at Eesti Energia. According to company CEO Sandor Liive, an alternative to the second unit could be nuclear and the company has the right to refuse the second unit for a year after signing the agreement.

But while emissions may be a concern for an EU member state, they weigh less heavily on the prospects for exporting oil shale technology. Eesti Energia plans investments of up to \$6 billion in oil shale development projects in Jordan, another country where oil shale represents the only major domestic energy resource.

Liive said Eesti Energia hopes to conclude an agreement with Jordan by year's end. "We have a strong MOU in place, and we are now finalizing the agreement," he said. Eesti Energia hopes to be able to develop an area with oil shale reserves of 2 billion mt in Jordan. However, the company cannot undertake such a big investment alone and is looking for partners.

Jordan has already signed oil shale MOUs with Brazil's Petrobras, France's Total, Russia's Inter RAO and is currently in talks with Anglo-Dutch major Shell. Liive said Eesti Energia had had requests from other

countries. "We have received many requests," he said, including one from a US company. "We have also had contact with Morocco and Russia, which has oil shale layers similar to ours," he said. Serbia is another country looking to exploit its oil shale reserves.

Oil shale's potential is not confined to power. Eesti Energia plans to produce considerably more shale oil for refining into transport fuels. "We will produce shale oil up to twice the value of current shale oil which will be suitable as feedstock for refineries to produce motor fuels," Liive said. In May, Eesti Energia announced plans to build a new oil shale processing plant in the east of the country at a cost of Kroon 3 billion (\$265 million).

Construction is to begin this year and the plant is to start initial operations in 2011, ramping up to full capacity in 2012. The new plant will use 2.26 million mt of oil shale each year, producing 290,000 mt of oil (5,800 b/d) and 75 million cubic meters of gas to be used in electricity generation. "Construction of the new oil plant is another step taken by Eesti Energia to establish a high-quality oil shale fuels industry in Estonia. It is also a precondition for offering our technology elsewhere in the world," Liive said.

Further plants are planned. "We plan to produce 30,000 b/d for the fuel industry by 2016," he said. Estonia's economy minister Juhan Parts said "Our aim is to introduce technology to use shale oil in the transport sector. If at present 70% of shale is used for electricity generation and 30% in transport, in 10 years the shares will have shifted upside down."

Broader application

Oil shale represents a significant unconventional oil resource, but one which is expensive to exploit. A recent study by the US Geological Survey estimated that the Eocene Green River Formation in the Piceance basin in western Colorado in the United States held a total of just over 1.5 trillion barrels of oil, although this was not an estimate of what is technically recoverable. The US is thought to have the largest oil shale deposits, accounting for about three-fifths of the world total.

Similar processes to those used for oil sands are being investigated for the retrieval of oil from oil shale. Oil shale can be mined conventionally before being heated to separate out the hydrocarbon content, which comes in the form of kerogen. This has to be upgraded to a synthetic crude. An alternative is in-situ processes which involve heating and producing the kerogen underground through the injection of steam. Neither process has been proved commercially viable in the US, while the technical viability of in-situ production processes also remains open.

However, a key barrier to developing oil from oil shale technologies is not just the processing costs and technology, but the environmental impacts. CO₂ emissions are not the only challenge as conventional surface mining would have a large impact in terms of land use, and there are serious issues surrounding ground water contamination with in-situ processes.

Gazprom targets Asia and oil

Hit by the fall in European and domestic demand for natural gas, Russia's state-owned gas company Gazprom will reduce its overall capital expenditure in 2009 to Rb500 billion (\$16.06 billion) from Rb637 billion. Within this, the company is seeking to expand its access to new markets and diversify its products base.

An additional Rb30 billion will be spent on the construction of the Far Eastern gas pipeline from Sakhalin to Khabarovsk and Vladivostok this year. By contrast, start-up of the giant Bovanenkovo gas field will be put back by one year to third-quarter 2012, as Gazprom does not foresee a need for the field's gas until then. Gas from Bovanenkovo would be taken by a new pipeline to Ukhta, where it would feed into pipelines connected to European markets. The move will also help Gazprom redirect investments towards the Far East, in order to complete the pipeline from Sakhalin to Vladivostok in 2011, as planned, Gazprom deputy CEO Alexander Ananikov said.

Price remains a stumbling block with regard to the Chinese market. Russia and China signed a number of memorandums of understanding to expand cooperation, including in the natural gas sector, during a visit by Chinese President Hu Jintao to Moscow in June. However, deputy prime minister Igor Sechin said progress on gas supply talks was expected only in October. Sechin said in late May that Russia expected to announce its proposals on future gas supplies to China during Hu's visit. Ananikov said there was no price agreement yet, and no way for pipeline supplies to start in 2011 as previously planned. Gazprom has been in talks with China about a gas deal since March 2006, but there have been no firm arrangements to date.

Gazprom has also announced that it plans to work out proposals in first-quarter 2011 to develop gas-to-

liquids production. The research into GTL technology would be complete by end-2010, the company said. Gazprom's executive board considers synthetic fuel production from natural gas as a priority for innovative development. Gazprom has jointly studied GTL opportunities with ConocoPhillips, Syntroleum and Shell, but says it will develop own technology.

Energy minister Sergei Shmatko last year said that the country had revived plans to develop GTL, a technology largely neglected in Russia, owing to its high costs. Gazprom plans to use gas from smaller or declining fields, as well as associated gas, for GTL projects. Shmatko said the latest research proved there were "interesting ways to cut capital expenditures," reducing the main drawback of GTL projects.

Gazprom's interest in oil is not confined to GTL. Its oil subsidiary, Gazprom Neft, appears to be faring better in the investment stakes than gas projects targeted at the European market. Gazprom Neft plans to start crude output at its new Novoportovskoye field on the remote Yamal Peninsula by year's end, according to Gazprom Neft CEO Alexander Dyukov. He added that the company had also started developing the Mesoyakhinskoye field in the north of West Siberia, which the company is developing with Anglo-Russian venture TNK-BP.

Gazprom Neft may increase investment by \$200-\$300 million in 2009 because of improving market conditions, said CFO Vadim Yakovlev. "Gazprom Neft now expects its operating cash flow to be higher than initially envisaged by the business plan," he said. Gazprom Neft previously expected its capital expenditure in 2009 to be \$1.9 billion, compared with \$3.327 billion the previous year. In addition to higher than expected revenues, a reduction in contractors costs and a weaker ruble have improved Gazprom Neft's scope to increase investment.

Namibia sees progress on CNG option for Kudu

Permission for the multi billion-dollar development of the Kudu gas field could be granted in first-quarter 2010, if the scheme's partners can agree on an affordable gas price, according to Namibia's energy minister, Erkki Nghimtina. In the event of no agreement between majority shareholder, Tullow Oil, and local utility Nampower, the minister said the government should take the decision to extract the gas and export it.

"Currently the gas in the ground benefits no one, but if we export it, Namibia will earn considerable income through royalties and taxes," the minister was reported as saying. More importantly, he added, Namibia would become a gas-producing country, and create jobs and associated industries.

Nghimtina said the Compressed Natural Gas development option, which is expected to cost nearly \$1.8 billion and would be the first of its kind, as well as indicative gas prices, were to be presented by Nampower and Gigajoule, the main gas buyer in South Africa, by end-June. Hopefully, the upstream partners –Tullow

(70%), Itochu (20%), and Nampower (10%)—would follow in July by signing an agreement and submitting a revised development plan, he said.

The revised plan will replace a proposal to pipe gas to South Africa and instead use CNG technology to transport gas from the offshore field to the industrial gas market in South Africa's Western Cape, and to a gas-fired power station in Walvis Bay, Namibia. Once an agreement has been signed and an MOU reached with Gigagoul, the parties will then have to apply to the country's minister of mines and energy for a 25-year production license. After this, Tullow will undertake a six-month front end engineering and design study.

Only then can the partners start to negotiate commercial agreements, the minister said, adding that a final investment decision was likely in first-quarter 2010. The physical development of the project will take about three years, and provided all goes smoothly, production is scheduled for March 2013. Kudu is currently thought to contain recoverable gas reserves of about 3 Tcf.

Chinese LNG imports jump

China's LNG imports shot up to their highest-ever monthly level in May, up 6.75% year on year to 511,017 mt, and more than double April's 200,105 mt, according to the latest customs figures. The country also continued to broaden its supply sources.

The jump reflects the start of imports through CNOOC's new Fujian LNG terminal, which received the country's first-ever Indonesian cargo, at a price of \$182.54/mt (\$3.51/MMBtu). CNOOC has a contract with Indonesia's Tangguh project, which was due to start up earlier in the year. However, owing to delays at the project, Indonesia has been using cargoes from its Bontang terminal to fulfill Tangguh obligations, and China seems to have received one of those cargoes.

The jump in Chinese imports also reflected an uptick in imports from Australia. China imported 318,282 mt of LNG from Australia in May, up 34% from May 2008. That volume was also up 142.73% from April. The price paid for the Australian LNG was just \$161.13/mt (\$3.10/MMBtu). It was the lowest price paid by China for LNG that month. China's Guangdong LNG terminal has a long-term supply deal with NWS that began in 2006. The contract is among the lowest priced in Asia, with an oil cap of about \$25/barrel in the price formula.

The remaining imports seem to have been spot purchases. One cargo came from Equatorial Guinea, at a

price of \$4.99/MMBtu. The last time China imported a cargo from there was in August 2008. And China saw a further broadening of its supply base with its first-ever import from Russia, which started up its Sakhalin 2 LNG project in March. China imported a single cargo from the country at a price of \$4.76/MMBtu.

While prices for both those cargoes are above the price of the term cargoes, they are well below term contract prices seen elsewhere in Asia, which have been above \$6/MMBtu for much of the year.

China saw no imports from Malaysia in May, for the first time since December. China usually takes at least one small cargo from Malaysia each month, which is used at a small peak shaving LNG facility in Shanghai.

With the start-up of the Fujian LNG terminal, China's regasification capacity has risen to 6.3 million tons per annum (8.7 Bcm/yr). With new terminals coming on line in the next few years, Chinese regas capacity should rise to 18.5 mpta by end-2011.

While this remains small in global terms – Chinese regas capacity in 2011 is expected to make up 6.3% of Asian capacity and just 2.5% of world capacity – demand for gas in China could see much higher utilization rates than for example in the US. There, investment in regasification infrastructure has run far ahead of real demand as domestic gas prices have fallen.

Gas hydrates promise new unconventional resource

While the unconventional gas boom has brought to market huge new onshore resources, the US holds longer term gas potential in the form of gas hydrates. An expedition by the US Geological Survey reported in late May the results of a 21-day drilling program, which confirmed that gas hydrates can and do occur at high saturations within reservoir quality sands in the Gulf of Mexico. Formerly, most marine gas hydrates were thought to occur in sands with little or no permeability.

Highly saturated hydrate bearing sands were discovered in at least two of the three sites drilled. Gas hydrates were found in saturations ranging from 50% to more than 90% in high quality sands in close accordance with predictions. The drilling took place on Walker Ridge block 313 and Green canyon block 955 and in the Diana subsea basin in the Gulf of Mexico.

Gas hydrates are known to exist in large quantities around the world, with the potential resource exceeding that of known conventional gas resources. Gas hydrates occur at particular temperature and pressure conditions and are found predominantly in Arctic continental areas and marine continental shelves.

Last year, the UGS completed its first assessment of the undiscovered technically recoverable gas hydrate resources on the North Slope of Alaska, where it estimated the mean resource at 85 Tcf. It said there was a 95% probability of 25 Tcf, 50% probability of 81 Tcf and 5% probability of 156 Tcf. This represents gas

that can be discovered, developed and produced using current technology. This was the first time, according to the USGS, that gas hydrates had been assessed as a producible resource occurring in discrete hydrocarbon traps and structures.

In its report, the USGS wrote, "Although verified by only limited field testing, numerical production models of gas hydrate-bearing reservoirs overlying the Milne Point and Prudhoe Bay oil fields suggest that gas can be produced from gas hydrate with existing conventional technology."

In 2002, the Mallik Gas Hydrate Production Research Well Program, which took place on the Mallik gas hydrate field in the Mackenzie Delta in Canada proved for the first time that production from gas hydrates was technically feasible. The program involved the drilling of three wells as part of an international research program, led by Natural Resources Canada.

A 1995 study that looked at the total gas hydrate resource in place put the potential US Alaskan resource at 590 Tcf. This assessment also included Federal offshore water not included in the 2008 program. Research at that time put the total US methane hydrate resource at 112,765 Tcf (95% probability), with a mean estimate of 320,222 Tcf. Other research has suggested that the US holds maybe one quarter of the world resource, although estimates vary. By contrast, proved US natural gas reserves currently stand at 237 Tcf.

Chile to see first LNG delivery in June

The first vessel bearing LNG for Chile left port in Trinidad and Tobago on June 8 and was due to reach the South American country on June 28, according to GNL Quintero, operator of Chile's first LNG terminal. The BG-owned ship *Methane Jane Elizabeth*, with 145,000 cubic meters of capacity, will head along South America's Atlantic seaboard, through the Straits of Magellan and to the Quintero terminal, 160 km (100 miles) northeast of Santiago. GNL Quintero said the vessel will moor at its quay for 45-60 days for testing and start-up of the regasification plant. The terminal is then expected to receive LNG deliveries every two to three weeks.

BG owns 40% of GNL Quintero's parent company GNL Chile with a pool of consumers holding the balance. BG Group will supply the terminal from its global portfolio of LNG projects, while Chilean state oil company ENAP, gas distributor Metrogas and generator company Endesa Chile have agreed to buy a total of 6.5 million cu m/year over the next 21 years.

The Chilean government sees the fuel as providing a secure supply of gas to replace fluctuating imports from neighboring Argentina, which have threatened the country's electricity networks with rationing. "There is no doubt that the arrival of LNG to our country will put us in a new situation in energy matters," Chile's energy minister Marcelo Tokman said. Meanwhile, environment minister Ana Lya Uriarte highlighted that LNG would help clean up polluted air in Santiago and other cities by allowing industry to reduce consumption of dirtier fuels like coal and diesel. A second terminal being built by EDF Suez and Chile's state copper company Codelco to supply gas to copper-rich northern Chile is due to begin receiving shipments early next year.

The new terminal is South America's fourth. Argentina has regasification capacity of 7.7 Bcm/yr and Brazil 7.3 Bcm/yr. All have been commissioned in response to the unreliability of Argentine and Bolivian gas exports in the region in recent years.

Australian coal seam gas developers look for partners

Companies such as ConocoPhillips and Australia's Santos are among those looking to collaborate on coal seam gas-based LNG projects in Gladstone in eastern Australia. Although extremely difficult to pull off, collaboration makes a lot of sense, largely because it significantly improves the capital efficiency of the projects, Santos CEO David Knox said. "We have a project we can deliver without collaboration but I would welcome it if it's possible," he added. Santos has already teamed up with Malaysia's state-owned Petronas to pursue its Gladstone LNG project, which will initially produce 3.5 million tons per annum of LNG.

ConocoPhillips was responsible for the largest oil and gas sector acquisition of 2008 when it agreed to pay Australian integrated energy company Origin Energy nearly \$8 billion for a 50% share in its proposed coal seam gas-to-LNG project in Gladstone. The deal's size stood out from a rash of acquisitions centered on the Queensland coal seam sector, which has also attracted the interest of global gas majors BG Group and Shell.

ConocoPhillips and Origin have formed a joint venture, Asia Pacific LNG, to develop their reserves through an LNG project comprising up to four production trains of 3.5 mtpa each. The companies are planning to make a final investment decision on the project in 2010, with first LNG targeted for 2014.

UK-based BG Group is also developing a 7.4 mtpa LNG project in Gladstone based on coal seam gas it gained through recent takeovers of Queensland Gas Company and Pure Energy. Shell has launched studies for its own stand-alone plant in the port city, in addition to its joint venture with Arrow Energy, which has signed up to supply coal seam gas to a 1.5 mtpa LNG plant to be built by Liquefied Natural Gas Limited. Canada's LNG IMPEL is pitching for an open-access LNG plant in Gladstone with up to three trains of 0.7-1.3 mtpa each.

According to Ryan Lance, a ConocoPhillips senior vice president, "There are a lot of projects being talked about and with the current economic recession and global downturn, folks are wondering is there enough demand for the LNG that's out there. We believe there is...and [that] once we come out of this economic recession, especially with the conversation around climate change and CO2...that LNG will actually be a fuel for the future," he added. "We'll go through a bit of a lull for a while, but long term we think it's a good business."

At Santos, negotiations with potential customers are "going well" although the proof would be a heads of agreement, Knox said. He conceded that Japanese buyers were currently going through tough times. "To get them to sign [an HOA] is not that straightforward right now...It's a matter of us presenting a good enough case and sufficient surety of FID next year and first delivery in 2014 to persuade them to do so."

The Gladstone LNG projects are among a raft of developments being planned in Australasia. Chevron and ExxonMobil are leading LNG projects at Gorgon in western Australia and Papua New Guinea, respectively, and Woodside is planning the development of its Sunrise and Browse projects in northwestern Australia. Japan's Inpex is also pursuing plans to develop the Ichthys gas field to supply an LNG plant in Darwin.

However, despite the bullish mood, only three LNG projects are likely to reach a final investment decision in 2009, according to FACTS Global Energy Chairman Fereidun Fesharaki. He tipped Gorgon, ExxonMobil PNG and Pertamina's Donggi-Senoro LNG project in Indonesia's to win the go-ahead in 2009, with Inpex's Ichthys and one Gladstone coal seam gas-based plant possible for 2010. Among the Gladstone projects, which are very dependent on oil prices, Fesharaki forecast only two to proceed, but at a slow pace.

Downstream capital costs fall

The effects of the global economic slowdown and falling commodity prices have halted the rise in costs for designing and constructing downstream refining and petrochemical projects after years of steady escalation, according to the IHS CERA Downstream Capital Costs Index. Rising capital costs have caused a number of large-scale projects to be put on hold since oil prices starting falling last year. The DCCI index fell from 187 to 170, a decline of 9%. The values are indexed to the year 2000, meaning that a project that cost \$100 in 2000 would cost \$170 today. The drop reverses the 6% increase observed over the previous six months and returns costs back to levels last seen in late 2007.

"The downward pressures that began to materialize at the end of third-quarter 2008 have now taken hold on the cost of construction materials," said Daniel Yergin, Chairman of IHS Cambridge Energy Research Associates. "At the same time, slowing demand for both energy-related and general construction projects has slackened demand causing a further loosening of the construction market costs."

The fall in the index was driven by a sharp decline in steel costs (down over 25% over the past six months) and low oil prices – West Texas Intermediate averaged \$48/barrel for March 2009, compared with an average of \$120/b during the second and third quarters of 2008. While projects already under construction are

proceeding, the sharp decrease in demand and price for petrochemical and refinery products are challenging the economics of future downstream projects.

"We have seen a notable drop in new refinery project starts as companies react to low margins at a time of high costs and declining product demand," said Jackie Forrest, lead researcher for IHS CERA's Capital Costs Analysis Forum for Downstream.

"Due to the long time horizon associated with downstream projects, the slowdown in new project starts will lead to slower demand in the next few years for downstream construction markets." "Although equipment prices are starting to show signs of weakening, falling commodity prices have not yet flowed through the entire supply chain to allow for more significant price reductions," Forrest added.

All regions tracked by the DCCI showed declines over the past six months with Russia (-17%) and South America (-16%) among the sharpest. "In the past 6 months, the strengthening US dollar contributed to notable differences in regional costs", Forrest said. "Because downstream projects have a substantial percent of the total project costs procured locally, the strengthening US dollar worked to decrease project costs in many regions." In one case, the value of the Russian ruble (measured in US dollars) reduced the cost for labor in Russia by more than 25%, Forrest noted.

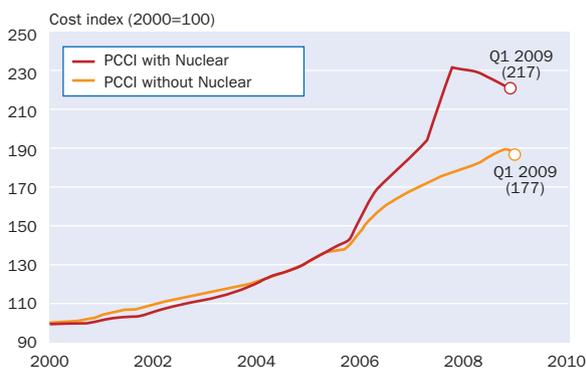
Power plant costs fall

The latest IHS CERA Power Capital Costs Index shows that the costs of constructing new power plants has fallen by a further 3% over the past six months, signaling a broader downward trend that has now spread beyond nuclear to all classes of power plants. The index tracks the costs of building coal, gas, wind and nuclear power plants and is indexed to the year 2000. It now registers 217 index points (down from 224 at end third-quarter 2008), indicating that a power plant that cost \$1 billion in 2000 would, on average, now cost \$2.17 billion.

The decline over the past six months was driven primarily by a decrease in costs of construction steel, wire, cables, rebar and asphalt stemming from sharply lower prices for steel, copper and petroleum. Though the overall PCCI has been trending downward since first-quarter 2008, the decline had previously been driven by one narrow factor – the fall in nuclear power plant construction costs – which masked continued cost escalation for other types of plant. This marks the first time in nearly a decade that the costs of non-nuclear plants have decreased.

Wind saw the sharpest decrease, of 11%, owing to a combined drop in wind turbine and tower costs and a short-term slowdown in orders. Lower costs for turbines, towers and construction could lead to a continued decrease in costs in the near term. Costs for combined-cycle and simple-cycle gas plants fell by 6% over the past six months as part of the larger trend in declining commodity and bulk materials prices. Coal power plant costs fell 6%, owing to declines in both labor and ancillary equipment costs. Costs for coal plants could decline further in the near term as continued uncertainty over environmental policy and higher financing costs cause the slackening of demand for new plants to persist, said CERA. The decline in nuclear plant costs slowed over the past six months, falling by 1%. Despite an active pipeline, falling steel prices are likely to push costs down further in the near term. The IHS CERA PCCI concludes that additional declines in costs are likely.

PCCI with and without nuclear



Source: IHS CERA

Dry freight rate rise may prove short-lived

Often taken as a proxy for an improvement in global trade, the jump in dry bulk freight rates may prove short-lived, according to a shipping source based in Singapore, who argues that the outlook for a freight recovery remains weak for this year and even for 2010. The Baltic Exchange Dry Index, or BDI, a weighted average of freight rates for key shipping routes, has more than doubled since April. The BDI stood at 4,291 points on June 3, compared with 1,574 points on April 1, having hit a low of 663 on December 5.

The Baltic Capesize Index, or BCI, also hit a high point on June 3 at 8,147 points, up 300% from 2,039 points on April 1. The BDI and the BCI have both tumbled since June 3, the BCI falling to 6,382 points on June 9, and the BDI dropping to 3,452 on June 10 before recovering towards the end of the month.

The shipping source, who requested anonymity, said that the spike in physical capesize rates in the first week of June was mainly due to a decision made in first-quarter 2009 by Chinese steelmakers to import iron ore, taking advantage of low spot prices and softer freight rates, as well as a weak US dollar. This trend didn't appear sustainable as China reduced iron ore purchases and more new vessels entered the market amid a period of tepid recovery for the global economy, he said.

"The main reason for the jump in capesize rates appeared to be the Chinese deciding to re-stock," the shipping source said. "The result of that sudden increase in demand in the first quarter was that [there were] a lot of ships fixed very quickly in the marketplace which pushed rates north," he said. He explained that when capesize vessels arrived in China after a voyage of 40 days to 60 days, their entry created a bottleneck in discharge ports in China with around 90 capesize vessels queuing up to deliver their iron ore cargoes.

"When you tie up about 90 ships for sometime between, say two and four weeks, or each ship is waiting two to four weeks to discharge, this really does take a lot of spot market tonnage out of the equation. And that will lead to higher freight levels and that was what we saw." A lot of capesize vessels were commissioned in first-quarter 2009, he said. "The impact was felt in the second quarter – by the time the ships got to China after a 40 to 60-day voyage," he added.

However, Capesize rates have gone down "quite considerably" since the first week of June "because it is felt that without the Chinese demand, the market just would not be able to sustain the increases over the last quarter," he said. Bullish sentiments have also been pulled back by talk in the shipping market that Beijing intends to lower the value added tax currently being levied on domestic iron ore supplies. This would effectively make it cheaper for steel mills to buy Chinese iron ore rather than imports.

Sentiment dented

"These little things being heard in the market are all denting sentiment a little. It's just felt that the market has gone too high, too quickly and there is nothing really

out there to sustain it in the longer term because the shipping market is not disconnected from the world economy," the shipping source said.

The jump in physical rates for relatively smaller vessels was not as spectacular as the spike in capesize rates. "The interesting thing this time is that the smaller units, the panamaxs, the supramaxes, and the handysize fleets, were not really affected that much," the source said. "It hasn't had the kind of impact on the other size categories because demand for coal and for grain and the smaller boat commodities have not risen in the same manner as it had for iron ore," he added.

Market weak out to 2010

Looking further forward, physical freight rates are bound to remain weak for the rest of the year, the shipping source said, adding that he would not be surprised if time chartered capesize rates go down to \$40,000/day. On June 8, the average capesize time chartered rate was \$70,630/day. "I think if it comes down 50% from where it is now, nobody will be that surprised. But this is because rates at the moment are still artificially high. Eventually, they will find their own level but at a much lower rate," the shipping source said.

He added that he expects physical rates for panamax, supramax and handysizes to also climb down. He said there is "still a huge amount of new building coming on stream" for smaller-sized vessels. "There's always talk of cancellation and deferment and people walking away from contracts and new buildings. But there's still a huge amount of ships going to be delivered. It's still going to have a negative impact on the market going forward," he said.

"I can't see this year being particularly firm. I think this year will remain weak and probably into 2010 as well. I think rates will still remain fairly weak for all sizes," he said. "If the world economy is still in the doldrums, then there is no way that the shipping market can buck the trend. The shipping market is still reliant upon the longer term health of the global economy," the shipping source concluded.

Baltic Exchange Dry Index



Source: © The Baltic Exchange

India key growth market for international coal

India's coal imports are moving upwards with a vengeance. This is particularly noticeable in imports of power-grade steam coal. Energy demand growth is consistently high as economic development continues apace and is leaping by 6% to 7.5% a year. Even so, there is sizable unmet power demand of 12% during peak hours and 7-8% at other times.

Power sector imports are surging. Figures available for the latest month, May, put the tonnage at 2.8 million mt against 2.4 million targeted. For April it was 2.6 million mt against the same target. A Coal India Ltd (CIL) source says at this rate India may not only achieve its projected power-grade coal import target of 28.7 million for the current year but may even exceed it.

For the last few years, the target for import was 20 million mt, but it was seldom fully utilized. NTPC Ltd, India's largest power utility, which accounts for a 27% share of total generation, more than doubled its imports from a year earlier, marking a monthly increase of over 110% during the last two months. The demand-led import surge could intensify in the coming monsoon months as domestic coal production suffers due to seasonal heavy rains. Existing port capacity may also be stretched during the monsoon, although quite a few all-weather ports have become operational.

India still has no definitive plan in place to cope with a projected domestic coal supply shortfall of 270 million mt when the government's Eleventh Plan ends in March 2012. The biggest miner, state-owned CIL, has been asked to produce 780 million mt, but production this

year is expected to total only 520 million mt. CIL accounts for nearly 90% of the country's total output. "We are flogging domestic production to make up the leeway in the remaining period, but we also know that we won't touch the tape in time," said a CIL source.

The new administration is expected to review the situation soon and update its coal demand and availability projections, as well as seeking "ways on how to make the best of a bad situation," the source said. "But let's face the fact – we see hardly any light at the end of the tunnel."

Energy demand, now rising at an average 7-8% a year, is expected to ramp up to even higher growth rates of 9% plus as urban consumption habits change. And once power supply shows signs of some improvement, the repressed demand will bounce back, off take will rise, and the crisis could deepen.

A step-up in imports is conceivably the only immediate way to cope with the shortfall. But there is more to it than just spending scarce foreign exchange on imported coal. World prices may rise as the size of Indian demand becomes clearer, just as China buoyed global commodity and freight markets to record levels until the financial crisis took hold.

World coal exports are only expected to grow by an extra 55 million mt to 70 million mt a year based on recent data, but use is restricted, owing to plant specifications. "That means the effective availability will be much less," says analyst Sujit Mitra. "To get the right type of coal at the right time is not going to be easy."

China's Shenhua plans seven CTL conversion centers

China's largest coal producer, the Shenhua Group, plans to invest Yuan 400 billion (\$58.5 billion) in developing seven coal conversion centers in the country to produce oil products, natural gas, methanol and olefins, according to the Chinese official news agency Xinhua.

The centers will be located in the Inner Mongolia autonomous region and Shanxi province in northern China, as well as Shaanxi province, Ningxia Hui and Xinjiang Uygur autonomous regions in northwestern China, the report said, quoting vice president of project planning with Shenhua Coal Liquefaction Corp., Zhang Diankui. The group plans to produce 30 million mt of oil products and chemicals annually through conversion of more than 100 million mt of coal by 2020, Zhang said.

Shenhua commenced operations at end-2008 at its first Coal-to-Liquids project in Inner Mongolia using self-developed direct coal liquefaction technology. The 1 million mt/year first phase of the Erdos CTL plant in Inner Mongolia is thought to be capable of converting 3.45 mt of coal into 1.08 mt of oil products. The plant's output consists mostly of gasoil, and to a smaller extent naphtha and LPG.

As the world's largest coal producer, China started encouraging the development of CTL projects a few years ago in a bid to reduce the country's reliance on

petroleum imports. However, CTL technologies release large amounts of carbon dioxide into the atmosphere and consume huge quantities of water, raising environmental concerns.

Work on most CTL projects in China was halted in September 2008 when Beijing asked local governments not to approve any new projects, saying that "coal liquefaction is a technology, talent and capital-intensive project, and most domestic enterprises lack advanced technologies, management experience and equipment."

The only exceptions then were two involving the Shenhua Group: the Erdos facility and the 80,000 b/d Ningdong coal liquefaction project jointly planned by the group's subsidiary Shenhua Ningxia Coal Group and South African oil and gas company Sasol, which has long experience in CTL technology.

Only in April, Chinese newspaper, the *China Daily*, reported that Shenhua had postponed a joint venture CTL project in the Ningxia Hui autonomous region with Shell. The report quoted Lim Haw Kuang, Shell's executive chairman in China. The project, which was estimated to cost \$5-6 billion, would have used Shell's own CTL technology and was expected to yield 3 million mt/yr of oil products. Shell signed an agreement with a subsidiary of the Shenhua Group in 2006.

APPA throws further doubt on US deregulated markets

The American Public Power Association, the US national association of publicly-owned and municipal utilities, has published a new report that throws further doubt on whether deregulated US electricity markets have provided any real benefit to consumers. The report says that rather than lowering retail electricity prices through competition, the wholesale electricity market operated by the PJM Interconnection has extracted large amounts of wealth from consumers to the enrichment of companies owning unregulated generation. The PJM Interconnection is a regional transmission organization that includes 13 northeastern US states and the District of Columbia.

According to the report, in 2007 and 2008, the generating segments of Exelon, Public Service Enterprise Group and PPL Energy realized annual returns on equity of 30%, three times the 10% returns for regulated companies. The return on equity for generators in PJM was \$4.9 billion higher than that of regulated companies in both 2007 and 2008, and \$20 billion higher over 2001 to 2008, the report said.

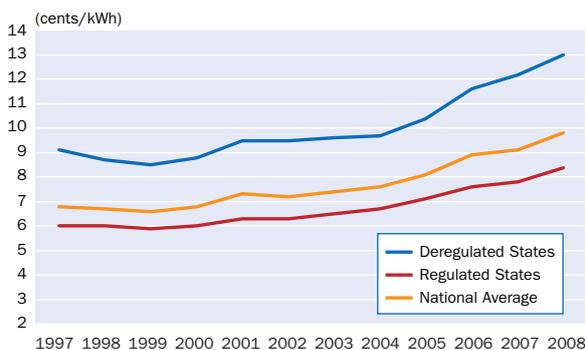
Average revenue per kWh (US cents per kWh)

	Deregulated states	Regulated states	National
1997	9.1	6.0	6.8
1998	8.7	6.0	6.7
1999	8.5	5.9	6.6
2000	8.8	6.0	6.8
2001	9.5	6.3	7.3
2002	9.5	6.3	7.2
2003	9.6	6.5	7.4
2004	9.7	6.7	7.6
2005	10.4	7.1	8.1
2006	11.6	7.6	8.9
2007	12.2	7.8	9.1
2008	13.0	8.4	9.8
Difference			
1997-2003	0.5	0.5	0.6
2003-2008	3.4	1.9	2.4
1997-2008	3.9	2.4	3.0

Deregulated states include: CA, CT, DC, DE, IL, MA, MD, ME, MI, MT, NH, NJ, NY, RI. Regulated states include all other states except for Texas

Source: APPA

Average Rates: Deregulated v Regulated States



Source: APPA

“Were these restructured markets truly competitive, as is claimed by their supporters, such high profits would bring additional entrants into the market and drive down prices . . . Anomalous financial outcomes, such as those experienced by these companies year after year, would be unlikely to occur in efficient competitive markets,” the report argues.

APPA has in the past compared rates in regulated areas to those of restructured markets, leading proponents of competition to defend reregulated markets by arguing that fuel costs are the main reason for high retail rates. “This analysis provides the other side of the story – that these price differentials cannot simply be a reflection of differences in costs if the profits of the deregulated companies significantly exceed those of regulated utilities,” the study said.

An APPA report, updated in March, said that increases in retail electric prices were significantly greater in states with deregulated electric markets than in regulated states, based on Energy Information Administration data. The deregulated category includes states located in markets under the jurisdiction of the Federal Energy Regulatory Commission and that allow end-use customers to choose their electricity provider (retail choice) but no longer have rate caps.

According to that report, “In 1997, the states in the deregulated category had average rates that were 3.1 cents per kWh above rates in the regulated states. Unfortunately, the retail choice experience – complete with the combined effect of divestiture of utility generating assets, and exposure of retail consumers to wholesale rates set in RTO markets – has resulted in an even larger gap in 2008, with deregulated states paying, on average, rates that are 4.6 cents per kWh above rates in regulated states.”

APPA has produced a string of reports criticizing the impact of deregulated markets in the US, noting in particular the difficulty new entrants face in entering these markets. Without new entrants, competition fails and incumbent power producers are left in control.

In a report published in August 2008 for APPA, economist Edward Chichanowicz noted the extended time period it takes to apply for permits for new coal-fired plants. The need for scale, which encourages the building of large units, is another barrier. Larger-scale investment favors developers with ready access to capital. In this regard, owing to subsidies of one form and another, and access to venture capital, renewables have been a more viable means of market entry.

Chichanowicz concluded by saying that two factors were particularly important in holding back new entrants – the rampant escalation in capital cost, and the prospects for CO2 emission limits. When he wrote in August 2008, he said neither showed any signs of abating. Interestingly, both now do; the various indices that measure capital costs are falling, while US cap-and-trade legislation is in the making. The latter is unlikely to favor coal, but it should provide policy certainty and thus remove a major risk factor facing would-be new entrants.

South Africa's Eskom gets rough treatment

South Africa must be one of the few countries in the world where a power price rise can draw anger, accusations, a threat of massed strikes, street protests and the kind of raucous, passionate debate usually reserved for elections. Yet this was the case when the national power generator Eskom put forward its proposal for a 34% hike in power tariffs to the National Energy Regulator of South Africa.

170 individuals and groups objected to the proposed increase. 25 were invited to give sworn evidence at public hearings in Pretoria on June 8-9. Outside the hearing hundreds of protesters waved banners, many mocking the national power generator with one word: "Eishkom!" In South Africa, the word "Eish" is a slang exclamation for a mistake or disaster.

Inside the massive auditorium sparks flew from the first word. Most of the critics complained Eskom had not been clear or detailed about its costs, nor about how it was going to spend the increased revenue. One of the fiercest critics of Eskom was the pony-tailed environmentalist, Christian Taylor, who spoke for the green organization, Earthlife, and went for the throat.

Taylor said: "If I had written a plan like this my board would have thrown me out, but who is kicking Eskom out? Ok, so Eskom needs money for capex, fine, but we need to know how that money is going to be spent wisely, after all it is our money, but we are not getting anything out of Eskom . . . For instance, if coal is on the way out in this country, why are we spending millions on three new coal-fired power plants? Earthlife believes Eskom's operations are not cost effective; the devil is in the detail, who is paying for what? This is not clear. We want Eskom to apply their minds a bit more."

Earthlife is also calling for Eskom to come up with a long-term funding plan as well as long-term controls. The group also wants Eskom to reveal the details of its long-term contracts with heavy users, such as the smelters of BHP Billiton, for cut price electricity. Many at the hearings complained that these long-term contracts for big users are being subsidized by everyone else.

Much of the stinging criticism came from green groups. John Joslin, environmental consultants of Smart Green Prosperity, claimed Eskom could save 12 GW a

year if it introduced more energy efficiency. Joslin said: "It is almost as if Eskom created the load shedding (power cuts) of last year to frighten everybody; then they went to their engineers and said: 'Dust off those old plans and let's go and get some bucks!'"

But big industry also weighed into Eskom. The South African steel employers' association, Seifsa, which represents 2,700 manufacturers employing 270,000 workers, warned that many firms could be forced to the wall, in these difficult times, if there was another major tariff increase.

The body said it could stand an increase of 15% this year and no more than 20% in any year. Guy Harris, of Siefsa, referring to the years of cheap energy in South Africa told the hearing: "Not enough has been done to smooth us out of the fools' paradise we were living in."

The Chamber of Mines also voiced its concerns, saying the power increase was not "well motivated" and that it was too concerned that there was a lack of detail in the application. On top of all of this, the South African Local Government Authority, which buys 40% per cent of Eskom's output to sell to consumers, challenged the legality of the tariff increase. Mthobeli Kolisa, on behalf of SALGA, said local authorities had not been given the time, required by law, to consult and make objections.

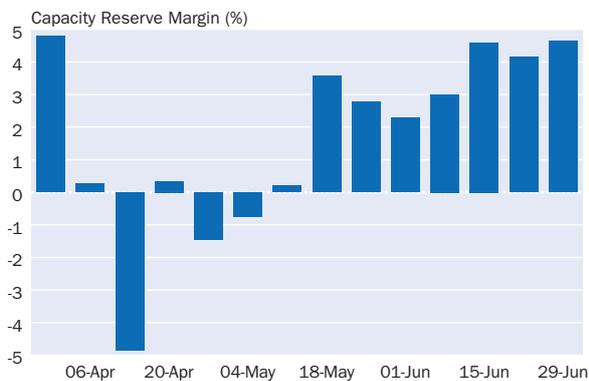
South Africa's coal companies also came under fire, accused of making high profits from supplying Eskom with the 125 million tons of coal it burns every year – while the rest of the country foots the rising bill. The Solidarity union called for an investigation into Eskom's costs, claiming coal companies are using a dominant market position to make handsome profits. Exxaro's after-tax profit last year was up 134% year-on-year and the net profit from its coal operations rose 200%. Anglo Coal and Xtrata's gross profits on their respective coal operations for 2008 were 89% and 251% up.

Sitting through the entire hearings was the urbane and highly paid CEO of Eskom, Jacob Moroga. Under Moroga's stewardship, Eskom has had to navigate stormy waters this winter with both the government and unforgiving customers on its back. Last year, an Eskom official went on TV to argue its case. As the interview began, there was a power cut leading the interviewer to open with the question: "How ironic is that?"

All of this flak must be endured by Moroga, who is an Eskom career man and an engineer by trade, as he tries to push through a Rand 385 billion (\$47.4 billion) capital expenditure program. The CEO told the hearings Eskom needs a "mountain of money" to keep up supply. Moroga told Platts: "It is a very difficult balancing act. We know that tariff increases are going to hurt business, but we have to make sure enough electricity is there for everyone in ten years time."

Eskom officials said the power generator was trying to double capacity from 40 GW to 80 GW by 2020. The regulator was expected to decide on the increase by end-June. Insiders say the regulator favours a more moderate 25%, but warns that if Eskom finds itself short of cash, it may ask for a 90% increase next year. "Eish!"

South Africa's thin reserve margin



Source: Eskom

Californian CSP scales up to GW size

Solar power plants are usually measured in MW, but not so in California, where two firms with different types of solar generating technology plan to build more than 3 GW of installed capacity. The power would be supplied to three local utilities within the next five years at a cost that could run to more than \$6 billion. Both developers hope to use federal stimulus money to finance what will be the largest solar projects in the world.

The gigantic projects will be built in a state where much of the solar development so far has been on the rooftops of homes and small businesses. A survey from the Solar Electric Power Association said solar capacity at leading utilities grew 171 MW last year to 882 MW, with the bulk coming from thousands of distributed generation projects mostly using photovoltaic technology.

The two companies intent on installing GWs of capacity will instead use Concentrated Solar Power technology. Stirling Energy Systems, based in Phoenix, Arizona, is owned by Irish firm NTR, while BrightSource Energy is a company with Israeli roots that is headquartered in Oakland, California.

Stirling proposes to build 1,750 MW of solar capacity and has set up a development company, Tessera Solar, based in Houston. Tessera's development team is focusing on two projects, both set to begin construction next year. The company has a 20-year power purchase agreement with Southern California Edison to supply up to 850 MW from the company's Solar One project. This would be built on 8,230 acres of federal land in California's Mojave Desert. Applications for Certification were filed with the California Energy Commission and the Bureau of Land Management in December.

Tessera's second project, Solar Two, is a 750 MW installation slated for 6,500 acres in the Imperial Valley, 100 miles east of San Diego. The project, which could be expanded to 900 MW, is supported by a 20-year PPA signed in 2005 with Sempra Energy's San Diego Gas & Electric. The company has said the "full build-out" of Solar Two will require completion of SDG&E's 150-mile Sunrise Powerlink transmission line.

Tessera's Sean Gallagher, vice president of marketing and regulatory affairs, estimates the capital cost of the first 500 MW of Solar One in the Mojave Desert at \$1 billion. To build 850 MW would take a workforce of 400 people three years and involve the installation of 34,000 of its trademark SunCatcher units, Gallagher said. Tessera says it intends to buy 90% of all components from US manufacturers. The company has begun talking with auto part manufacturers in Michigan and Ohio to determine their ability to retool factories to build an estimated 70,000 engines the company will need starting next summer. There is no word yet as to how Tessera intends to source the roughly 6 million mirrors it will need for the two projects.

BrightSource has a 25-year PPA with Pacific Gas & Electric covering seven projects totaling 1,310 MW of solar thermal power. The company will work first on three interconnected CSP projects to be sited on 3,400 acres of federal land near Ivanpah Dry Lake on the border

with Nevada in San Bernardino County. They will have a combined capacity of 400 MW. Construction is expected to be completed by fourth-quarter 2012.

Together, BrightSource refers to them as the Ivanpah Solar Electric Generating System, or ISEGS. The system will be interconnected to the Southern California Edison grid through upgrades to an SCE 115-kV line, which passes the site on a northeast-southwest right-of-way.

BrightSource's predecessor, Luz, built the Solar Electric Generating Systems in the Mojave Desert in the 1980s. The combined 44 MW SEGS I and II units are today owned by Solel Solar Systems and supply power to PG&E. The SEGS facilities have 936,384 parabolic mirrors covering 1,600 acres. The 310 MW SEGS III through IX system has been owned for 20 years by FPL Energy, now known as NextEra Energy. The seven units supply power to Southern California Edison and are considered the single largest operating solar power generating facility in the world.

Despite the 20-year hiatus, large-scale solar development has taken off in the US in the last few years. In June 2007, Spain's Acciona brought online a parabolic trough CSP system in Boulder City, Nevada, 40 miles south of Las Vegas, that is rated at 64 MW in full sun. The facility cost \$260 million.

In October 2008, Ausra flipped the switch on its Kimberlina CSP facility in Bakersfield, California. Ausra, based in Australia, employs its Compact Linear Fresnel Reflector solar collector and steam generation system originally designed in the early 1990s at Sydney University. The firm is developing a low-cost thermal energy storage system, which would allow power to be generated on demand, day and night.

CSP is typically priced from 10 US cents/kWh to 16 cents/kWh in 20-year contracts with utilities, according to Reese Tisdale, research director for Emerging Energy Research and author of a report *Global Concentrated Solar Power Markets and Strategies, 2007-2020*.

The price may seem high, but it is on par with gas-fired peaking plants, which is what CSP displaces. According to Michael Fritsch, president and chief operating officer of Confoe, a Texas consulting company, "You tend to get the peak power demand when it is hottest and sunniest because the power demand is for air conditioning. So your best power generation comes at times when you need the power most, which is a big benefit. When people argue wind versus solar, solar matches up better with the demand peaks." The DOE has set a goal of installing 1 GW of CSP in the southwestern states by 2010 in the hope that economies of scale will bring down the cost of the resource to 7 cents/kWh.

The CEC said in June that they have begun an environmental review of Stirling Energy Systems' Solar One Project. In a Federal Register notice, the BLM said it and the CEC intend to prepare a joint environmental impact statement and proposed land-use plant amendment for the project. Environmental groups are likely to question the impact of CSP on desert land.

Crude peaks

Front-month crude futures on the New York Mercantile Exchange dropped back below \$70/barrel in June, suggesting at least a temporary respite from the rise seen since a low was reached in February below \$40/b. Non-commercials, which are primarily comprised of hedge funds, had liquidated nearly 50% of their long position as of June 16, according to data from the US Commodity Futures Trading Commission, although they remained long to the tune of 26,430 crude contracts.

Two reactions were noticeable by their complete absence. Thousands of demonstrators on the streets of Tehran and other Iranian cities protesting the result of the disputed June 12 presidential election and an upsurge in violence in the Niger Delta would last year have sent already high oil prices through the roof. This time around the supply of surplus crude on land and offshore underlined that even these major events posed no real threat to physical supply. The lack of reaction supports the view that the recent rise in oil prices has been driven more by sentiment than fundamentals.

Higher prices have also brought more oil to the market. Output from members of OPEC governed by targets let slip their discipline in both April and May. This has been aided by a jump in Iraqi production as crude

from new fields in the Kurdistan region of the country has been allowed into Iraq's Mediterranean-bound export pipeline. Even if Venezuela, Nigeria and Ecuador cannot raise output, the rest of OPEC can, and they see no reason to be disciplinarians if the oil price appears firm.

On the demand side, the US gasoline season does appear to be taking place and consumption has stabilized, averaging 9.263 million b/d in the four weeks to June 12. This is just 28,000 b/d down on last year, but that was when pump prices were at record levels and demand was already depressed. US gasoline demand is still 2.6%, or 252,000 b/d, down on 2007.

In China, apparent petroleum demand in May rose 5.96% on the year to 33.23 million mt, according to Platts estimates, based on recent figures released by the Chinese government. The increase widened from a 4% annual increase in April, when the country's oil demand picked up for the first time since November.

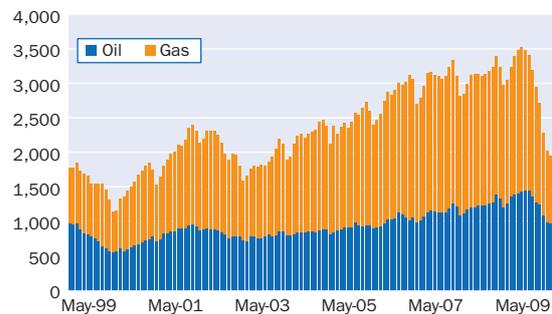
However, according to China Petroleum and Chemical Industry Association data, sales of key refined oil products reached 18.32 million mt in May, a 0.2% drop from May 2008. Chinese refiners produced a total 19.34 million mt of oil products, up 16.7% from a year earlier, marking an all-time high in crude throughput volume. Fuel inventories jumped 36.1% from a year earlier.

Oil forecasts (million b/d)

	Call on OPEC	Rise in non-OPEC supply	World oil demand	Rise in demand
June 2009 Forecasts for 2008 (million b/d)				
EIA	31.3	-0.3	85.4	-0.47
IAE	30.5	-0.2	85.8	-0.20
OPEC	30.8	-0.2	85.4	-0.50
June 2009 Forecasts for 2009 (million b/d)				
EIA	28.5	0.4	83.7	-1.70
IAE	27.7	-0.1	83.3	-2.50
OPEC	28.6	0.2	83.8	-1.60

Sources: EIA, IAE, OPEC

International rig count (monthly average)



Source: Baker Hughes

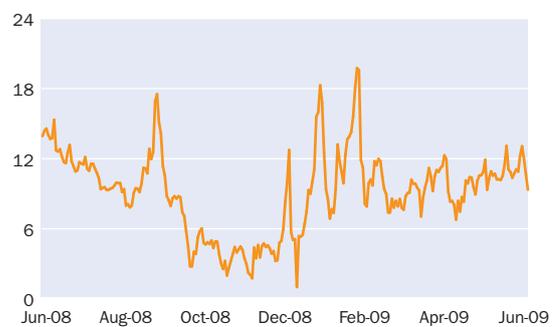
Dated Brent (\$/b)



1-year average to date: **70.74** 2-year average to date: **82.25**
5-year average to date: **67.07** 10-year average to date: **46.93**

Source: Platts Global Alert

NYMEX 3-2-1 Cracks spread* (\$/b)

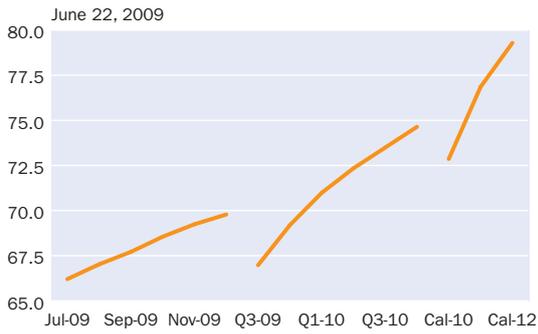


1-year average to date: **9.12** 2-year average to date: **10.30** 3-year average to date: **11.41**

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

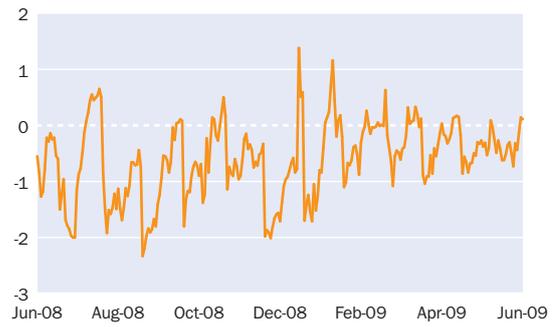
Source: Platts Global Alert

Platts forward curve for Dated Brent (\$/b)



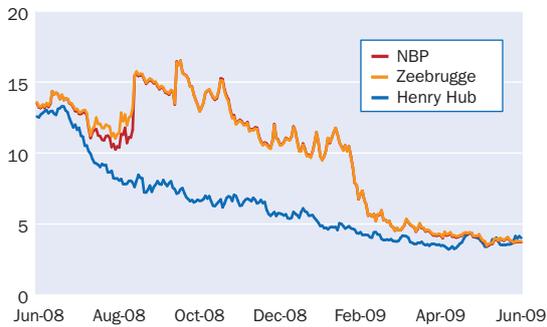
Source: Platts Forward Curve – Oil

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



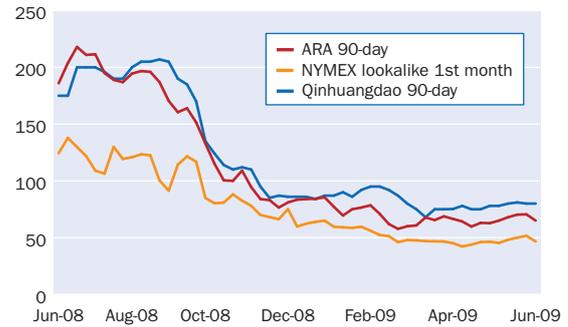
Source: Platts Global Alert

Natural Gas month-ahead (\$/MMBtu)



Source: Platts Gas Daily, European Gas Daily

Coal (\$/mt)



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

Source: Platts Coal Trader, Coal Trader International

Oil product comparisons (\$/b)

June 19, 2009

WTI front month: 69.65

Brent front month: 70.64

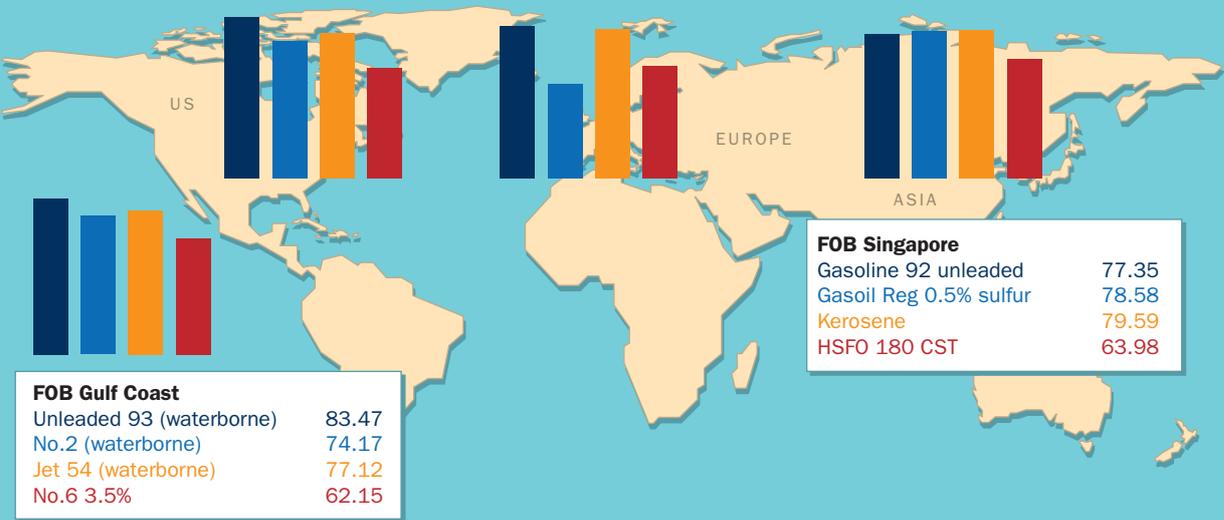
Dubai front month: 71.45

CIF NY

Unleaded 93 0.3% Barge	86.20
No.2 Barge	73.29
Jet Barge	77.54
No.6 3.0% Barge	59.25

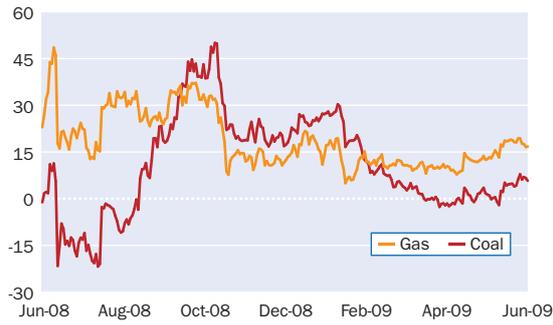
FOB Rotterdam Barges

Premium Gasoline 10 ppm	81.71
Gasoil 0.2%	50.30
Jet	79.87
Fuel Oil 3.5%	59.88



Source: Platts Global Alert

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



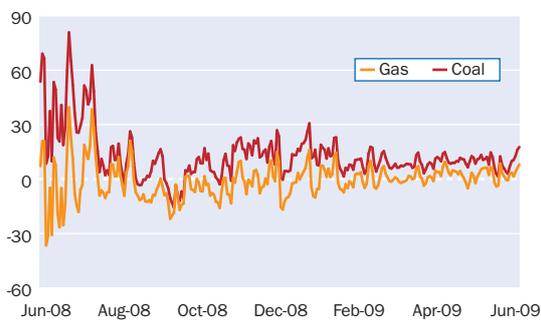
Source: Platts Emissions Daily

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



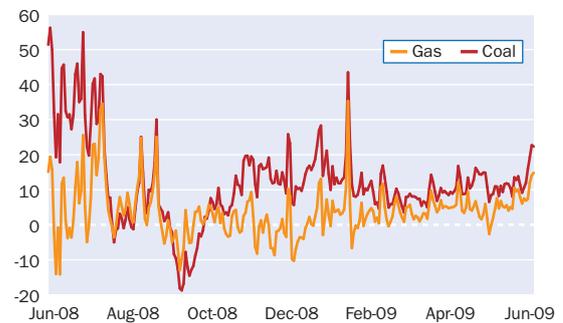
Source: Platts Emissions Daily

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



Source: Platts Emissions Daily

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



Source: Platts Emissions Daily

NWE Note: Based on typical kg 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 NO_x controls on coal stations resulting in 0.6 lb/mmBtu NO_x; benchmark coals meeting specifications for NYMEX look-alike and CSX-Big Sandy/Kanawha Central Appalachian coals, barged to Cincinnati and railed to Atlanta, respectively. For details, see methodology at platts.com.

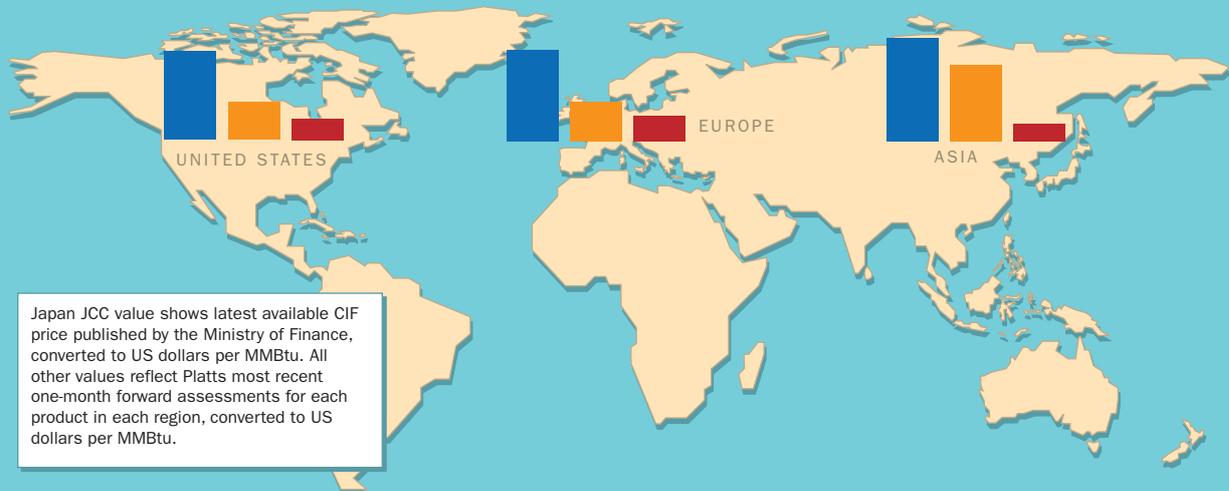
Comparative power feedstocks (\$/MMBtu)

June 19, 2009

NY Harbor 1% S fuel oil	9.51
Henry Hub gas	4.02
NYMEX coal	2.26

NW Europe fuel oil	9.81
NBP gas	4.25
ARA coal	2.73

Singapore fuel oil	11.09
Japan JCC LNG	8.18
Qinhuangdao coal	1.89



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

Source: Platts LNG Daily

Gas decouples from oil

Asian spot LNG prices saw some buoyancy in June as did futures prices in both Europe and the US, but prices failed to rally in the same way as oil, marking a widening differential between crude and gas. In Asia, owing to limited availability of spot cargoes and some buying interest for floating storage ahead of the summer, Platts' August Japan Korea Marker started June 16 at \$4.225/MMBtu and was later assessed June 18 at \$4.375/MMBtu, partly reflecting rises in prices at both the UK's National Balancing Point and US Henry Hub.

Traders said that China's CNOOC had launched a formal tender for an LNG cargo for second-half July, while further demand came from India, with at least one buyer looking for a July cargo independently from the local import capacity-holders. Supplies appear reduced in part as a result of sellers' earlier success in shifting cargoes from producers such as Russia's Sakhalin 2 and Australia's North West Shelf. Malaysia's Petronas was said to have no spot availability, owing to maintenance.

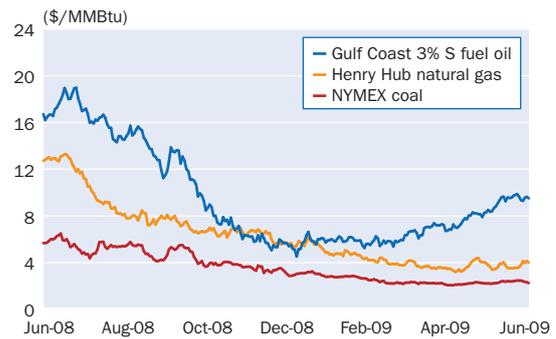
Developments in the shipping market indicated spot activity might be about to pick up. One shipping source said four short-term charters had been taken in two weeks, three by Asian customers. Two further LNG carriers were reportedly chartered for relatively long periods, of around four and a half months. In Europe, winter cargoes were said to be close to 80% of the NBP price, compared with around 90% for summer cargoes.

In the US, a stronger crude oil market and various technical indicators eventually gave gas futures a boost, but spot prices faced relentlessly bearish fundamentals. The July NYMEX gas futures contract broke to the upside on June 11, closing at \$3.933/MMBtu. After a brief retreat on June 12, it surged to a series of closes above the \$4/MMBtu mark, the highest being a 4.253/MMBtu settle June 17. Occasional bursts of heat in areas such as the Midcontinent, the Gulf Coast and the Southwest provided periodic support to prices, but the heat periods were generally neither severe nor lengthy.

The US EIA reported net storage injections of 106 Bcf for the week ending June 5 and 114 Bcf for the week ending June 12, bringing total supplies to 2.557 Tcf with more than four months remaining in the traditional injection season. Storage is well on track to surpass the threshold of 3 Tcf by the middle of July, roughly two months ahead of 2008's injection pace.

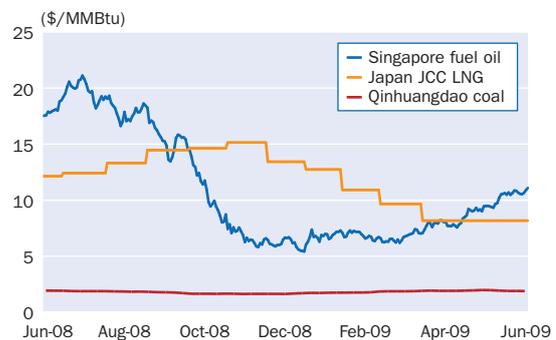
In Europe, UK NBP prompt gas prices were stable during most of June, owing in part to plunging summer demand that minimized the impact of field outages. Within-day gas opened the period at 26.85 p/therm on June 4, but had edged up to 28 p/th by June 18, as North Sea maintenance occasionally put stress on supply. But overall the system managed to retain its balance. Demand in the second week plunged to yearly lows of 196 million cubic meters. Waning appetites, further compounded by a steady stream of LNG, kept a lid on bullish impulses. Winter 09, which started the period at 50.9 p/th, dropped slightly to 50.8 p/th. Traders pointed to growing signs that the curve was decoupling from crude oil, for which highs in June hardly rubbed off on a bearish gas curve.

Comparative power feedstock prices: US



Source: Platts LNG Daily

Comparative power feedstock prices: Asia



Source: Platts LNG Daily

Comparative power feedstock prices: NWE



Source: Platts LNG Daily

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

Coal stocks grow

Prompt European delivered CIF ARA coal prices bucked the recent downward trend, defying seasonally low demand, growing stockpiles at European discharging ports and reports of unsold coal at origin ports. But towards end-June, a downward correction set in. By June 22, European spot prices had sunk below the \$60/mt mark. Overall, average CIF ARA prices for June rose by \$4.88/mt to \$68.58/mt, while South African FOB prices rallied to \$61.10/mt from \$58.03/mt in May.

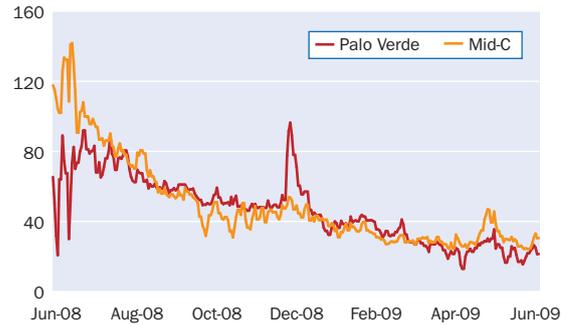
Traders said there was a significant overhang of coal in Europe, with stocks at northwest European

UK baseload month ahead (€/MWh)



Source: Platts European Power Alert

US day ahead (\$/MWh)



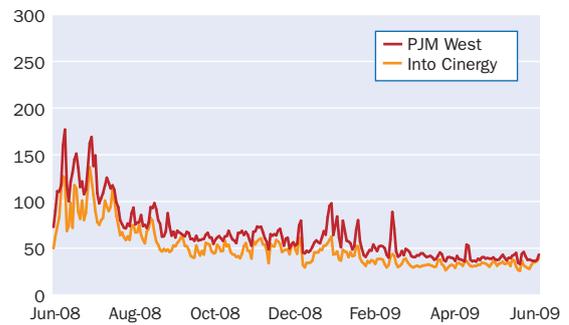
Source: Platts

Nord Pool system day ahead (€/MWh)



Source: Platts European Power Alert

US day ahead (\$/MWh)



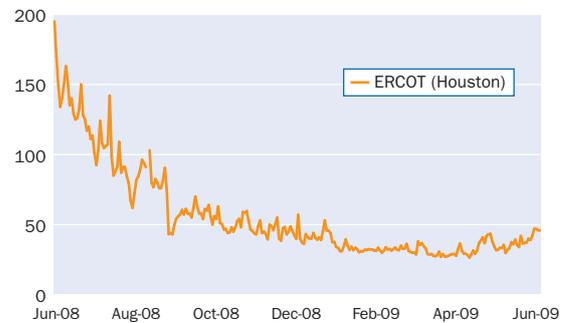
Source: Platts

European baseload month ahead (€/MWh)



Source: Platts European Power Alert

US day ahead (\$/MWh)



Source: Platts

discharging ports still climbing. The EMO terminal in Rotterdam now has 2.6 million mt of steam coal in stock, up from 2.1 million mt at end-May. Stocks at Amsterdam's OBA terminal have risen to 1.7 million mt, up from 1.25 million mt at end-May.

Future price direction depends on the level of coal inventories in Europe, the state of the underlying economy, summer coal burn and the weather. The steep contango in the API2 (CIF ARA) price curve is still allowing market participants to buy coal in the prompt and store it while locking in forward prices at a profit. But storage space is running out.

The South African Richards Bay FOB market is also seeing oversupply and weak demand, with spot prices sinking by several dollars to trade in the mid-\$50s/mt by

end-June. Indian traders and end users are said to be making fresh enquiries for July and August-loading South African coal due to the reduction in spot prices.

In the Asia-Pacific region, Australian Newcastle FOB spot prices dipped below \$70/mt, with the market gripped by talk of Chinese buyers seeking to delay delivery or even renege on deals altogether. Sustained Chinese buying has fuelled recent price rises, but sources say the bubble may now have burst.

On June 17, Japanese and South Korean buyers reached separate agreements with Chinese coal suppliers for a 2009 term contract price at \$78.50/mt FOB, basis 5,800 kcal/kg NAR. Buyers in both Japan and Korea are said to consider the price too high and have decided to cut their Chinese imports drastically.

EU carbon prices give up gains

The price of EU Allowances under the EU Emissions Trading Scheme eased in June, falling from a high of €15.70 (\$21.73) per metric ton of CO2 equivalent in May. EUA prices for delivery in December 2009 on the over-the-counter market have climbed in recent months following an all-time low for the 2008-2012 Phase II period of €8.33/mt on February 12. But prices succumbed to selling pressure in June, falling to a near-term low of €12.45/mt on June 15.

Gains on carbon prices from March to May were attributed to rising crude and equity prices, as well as recognition that prices as low as €8.00-€10.00/mt represented good value. But movements in late May and June suggested there is a limit to the extent to which carbon prices can continue to make gains on the back of more positive macro-economic indicators.

Traders pointed to a marked decoupling between carbon and crude. Brent crude futures contracts for August delivery on London's ICE Futures exchange powered up to \$72.55 per barrel at the close on June 11 – the highest price since November 2008. And while Brent values were holding up at \$69.19/b by June 19, carbon prices had drifted back to €13.40/mt.

Elsewhere, renewed warnings were heard over the risk posed to carbon markets by sales of national level Kyoto Protocol emissions allowances. In a letter sent to the Czech Presidency of the EU June 17, the International Emissions Trading Association said countries that have ratified Kyoto should not be allowed to bank their unused Assigned Amount Units at the end of the UN agreement's first commitment period because the practice could have a negative effect on carbon prices in markets such as the EU ETS.

AAUs are national-level emissions credits that industrialized Kyoto-ratified nations can trade with other countries struggling to meet their GHG emissions reductions commitments under the protocol. Most sales of AAUs have come from countries of the Former Soviet Union, which have the largest global surplus of AAUs, according to a Societe Generale/Orbeo document tracking the deals. AAUs cover the six GHGs regulated by Kyoto, and a single AAU is equivalent to one metric ton of CO2 equivalent emissions abated. Most of the surplus resulted from the economic decline and falling emissions witnessed in the FSU in the post-Soviet era, which came after the Kyoto protocol's 1990 baseline.

IETA said in the letter that "many surplus AAUs are being sold at present to Japan and other countries expected to be short in 2012," and the group estimated that there are "many more" national surpluses of AAUs – particularly in Russia – possibly between 4 billion and 6 billion mt that could be carried over post-2012.

EU ETS Directive regulations block private companies from buying AAUs from national governments to then sell on to other governments, but the IETA said in the letter that demand for the credits by EU ETS participants from

2012 to 2020 will be 2.2 billion mt if Kyoto is not amended to prevent banking of the credits.

IETA said the EU should submit an amendment to Kyoto proposing that the UN Framework Convention on Climate Change alter the agreement so that AAU banking is not permitted after 2012, which is when the first commitment period for the treaty expires. Without the amendment, sales of AAUs post-2012 will only increase, causing countries failing to meet their future emissions caps under the second commitment period to rely more heavily on buying credits from other countries.

IETA European Policy Director Michaela Beltracchi said: "A full or substantial transfer will distort calculations of the true impact of post-2012 [emissions reduction] targets and destabilize the market by undercutting savings achieved through the Clean Development Mechanism or other mechanisms."

June 17 was the UNFCCC deadline for submission of amendments to the Kyoto Protocol ahead of a meeting of parties to the agreement in Copenhagen in December, where a successor agreement is set for discussion. But the IETA said that a packet of amendments sent by the EU to the UNFCCC June 11 did not contain an AAU banking proposal, although it did admit that at least one other Kyoto Protocol ratifier had sent such an amendment in time to meet the deadline..

As an alternative to getting rid of the surplus AAUs, Beltracchi suggested that they be 'greened', meaning that the money from AAU sales be spent on domestic environmental projects.

CO₂ price trend (€/mt)



Source: Platts Emissions Daily

Platts CO₂ assessment monthly averages – 1-24 June, 2009 (€/mt)

Delivery	High – Low	Midpoint
Dec-09	13.52 – 13.48	13.5
Dec-10	14.13 – 14.09	14.11
Dec-11	14.71 – 14.67	14.69

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

Source: Platts Emissions Daily