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Oxford Energy Forum **was conceived from its beginnings as a debating journal. We welcomed therefore the presentation of different, or indeed contrasting, views on the themes selected for every issue of the journal. And we always invited readers to send letters to the Editor commenting on articles published in *Forum*. We are delighted with the response to this invitation, which is resulting in the publication of four excellent letters in this issue.**

The article on Liquefied Natural Gas (LNG) by Wietfield and Fenzl (*Forum* 76, February 2009) has attracted three letters, all of them complimentary to the authors and complementary to the points raised in the article. Howard Rogers and Michael Stoppard both focus on the changed market situation which heralds in an era of surplus gas supplies. This expected surplus is due to a fall in the demand for gas caused by the recession, to the unexpected emergence of shale gas in the United States, and to a surge in LNG supplies arising from projects coming soon on stream. Will these developments cause an increase in short-term international gas trading or a rush back to the safety of old style long-term contracts? Our correspondents have interesting things to say on this intriguing question.

The third letter on LNG is by the *doyen* of gas experts – Jim Jensen. He points to the significance of 'self-contracting' – the system by which producers take the forward market risks by supplying final customers themselves. Jensen also reminds us that the risks have migrated upstream.

Jonathan Stern's letter is about the failure of the EU to allocate sufficient funds to gas storage and interconnections to Eastern Europe, the region most affected by the Russo-Ukrainian dispute. Gas supply interruptions are likely to occur in this context in the future. But EU policies often leave much to be desired because they cannot be agreed upon unless every Member Country gets some benefits or recompense.

The theme of the main debate in this issue is the impact on oil investments of low prices and the current economic recession. Our authors are in agreement on the fact that investments are being curtailed. There is, however, a strong conventional wisdom held by many consultants, commentators and some international organisations that

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insufficient investment today will cause oil prices to explode as soon as the economic recovery sets in. Haas and Terzian hold this view.

Morse disagrees and backs his position with a number of interesting arguments. He takes issue with the exaggerated pessimistic forecast of future global oil supplies. One question which forecasters do not address is: how long and how deep will the reduced capital flows be? Then, one needs to know where capital expenditure cutbacks are being applied.

Development drilling, for example, appears to be less affected than exploration drilling. Furthermore, investment costs are falling. Thus a reduction in the capex is smaller in terms of what can be done in real terms than may at first appear. And Morse proposes other arguments of interest.

We definitely have a debate here and hope that this will elicit a lively correspondence from our readers.

Within the same theme, Aissaoui assesses the investment situation in the Middle East/North Africa region and shows the extent of project postponement or outright cancellation. A key feature of his methodology which 'relies on a real world project-based approach' is that the usual determinants of investments, demand and prices, are treated as implicit, but costs and funding availability are explicit inputs. He has things to say about changes in capital structures and cost profiles.

Three articles on diverse but very topical topics complement the issue. Mabro compares the causes of the 1998 and 2008 price collapses. The causes were different but the results almost identical. The first crisis was due to conflicts between members within OPEC. What did happen in 1998 started as an undeclared price war. Ten years later market hubris caused prices to rise to such a high level that, from that point, the only path open to the market was one of a vertiginous descent. In both cases the term price structure in oil futures markets was in contango. This played a visible role in bringing prices down in 1998. The 2008–9 contango has not attracted much attention from analysts as yet. The resulting build-up of inventories, however, is depressing prices.

Haug returns to the theme addressed in the previous issue – EU energy policies – but she introduces new dimensions. She discusses technological market failures. However, she finds hope in the huge funding stimulus for RD&D promised by the US administration despite many uncertainties about possible responses. In any case the signaling involved should not be overlooked.

Finally Boué is concerned by a problem that is primarily Venezuelan but has wider implications. He argues that the Venezuelan oil production data published by the 'secondary sources' (a group of world reporting agencies), the IEA and even the OPEC Secretariat underestimate the actual volume. He blames those who supply the data to those who publish them. Are they simply trying to suggest that President Chávez' regime has irreparably damaged the country's oil industry? There is a broader dimension to all that. The reliance on 'secondary sources' to appraise the state of oil supplies can have distorting impacts on the determination of oil prices. It is also odd that OPEC, whose only policy instrument is production quotas, has not yet established a reliable system of output reporting by primary sources.

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The Impact of Low Oil Prices on Investments

Edward L. Morse believes the supply shortfall may fall less short than assumed

Following the dramatic collapse in oil prices by well over $100 per barrel after July 2008, many oil and natural gas companies, confronting significantly reduced cash flows, also cut their upstream capital expenditures, leading to widespread forecasts of another supply crunch on the near term horizon. For some analysts the presumed supply shortfall was just around the corner – as soon as demand rebounds along with a revival in economic growth, a combination of factors, including an acceleration of depletion in maturing non-OPEC oil fields and lower expenditures on new field development, could bring prices back above $100 per barrel in two years. For others the supply crunch would not arrive until three or four years from now, but it is nonetheless inevitable.

There are good reasons to question these dire forecasts. They all begin with the consensus that emerged after 2003 that the peak oil school had it right – that conventional oil production had peaked and that eking out incremental volumes of non-conventional crude oil (syncrudes, condensates and other natural gas liquids, gas-to-liquids processes, and biofuels) was both expensive and difficult to sustain. The consensus has been reinforced of late. The International Energy Agency, which issued a massive report on the accelerating rates of depletion last fall (*World Energy Outlook*, November 2008) indicated that without capital expenditures, average mature field depletion would increase from 7.7 percent to 11 percent. In the April 10 issue of the IEA's *Oil Market Report*, the organisation indicated that 1 mb/d of oil projects were subject to delays and cancellations in 2009–10 and that with lower investments in mature fields, it had increased its assumed decline rates there from 7.7 percent to 9.4 percent (by 20 percent), putting 360 kb/d at risk by end 2010. An array of independent analysts have also chimed in, with perhaps the most dramatic revisions found in reports of CERA, indicating that between 2009 and 2014, a presumed net increase in output of 14.5 mb/d could well be slashed by 7.6 mb/d, or 52 percent of net projected growth.

What's potentially wrong and misleading about these pessimistic projections of global supply? Let's look at a series of factors.

> "development drilling, the most critical issue for near term supply, is not much lower than it would otherwise have been"

First is the critical issue of how long and how deep the reduced capital outflows will be. It makes a big difference if the reductions are to last one year or five. Surely, if and as oil prices increase so will capital expenditures.

Second is the equally important question of what, at a micro level, lower capital expenditures bring. To be sure, there has been a dramatic falloff in the rig count in North America, particularly natural gas. But so far, natural gas output continues to grow in the United States, for reasons that have to do with the nature and location of continued drilling. Nonetheless, the drop in the total US rig count from 1839 in May 2008 to 945 in May 2009 is not being repeated elsewhere in the world. When it comes to drilling, it is important to understand its focus. What portions of the cutbacks are in exploratory drilling, delineation or development? It seems clear that most of the cutbacks have been in exploratory drilling by independent and smaller companies, constrained as these cutbacks might be by mandatory drilling to fill lease working requirements. To date it remains clear that development drilling, the most critical issue for near term supply, is not much lower than it would otherwise have been.

Third is the question of costs. The period of 2003–08 represented a time when total upstream capital expenditures are estimated to have risen from $200 billion annually to an annualised $455 billion. But this was also a period of time when costs of finding and developing oil are estimated to have grown by over 100 percent, virtually negating the impact of increased expenditures. Today's upstream sector is seeing a remarkable cost deflation, which might well be falling by 5 percent per month in North America. To be sure the costs of some contractual work are sticky. This is particularly true in the deepwater play globally, where long-term contracts of five to ten years in duration were essential for new construction to take off. But costs are coming down and that changes significantly the calculus required to understand the efficiency of capital outlays. It has been estimated by some equity analysts that overall upstream capex this year might be 20 percent below last year's level. But if costs are down by at least 20 percent, the efficiency of capital outlays might well be 20 percent higher this year than last and growing.

Fourth, and directly an offshoot of falling capital costs is the way expectations about costs impact the timing of investments. A noteworthy feature of today's market is the increased competition in the services sector, which leads services firms with long-term contracts that are up for renewal, to bid low in order to secure contracts. It has been widely reported, for example, that in Mexico, Halliburton, Schlumberger and Weatherford reduced contracts significantly in order to secure renewals. Yet expectations of continued cost savings are leading to the postponement of high marginal cost projects. This negotiation-related reduction in capital outlays is especially vivid with respect to Canadian oil sands projects. A year ago the all-in costs of such projects were over $90 per barrel. Already these costs have fallen significantly and may now be in the range of $60–70 per barrel. It appears that a number of companies believe that by next year at this time these contractual costs may fall to the $40 range, at which point they will be prepared to revive their postponed projects. It is important in looking at declining outlays to make a judgment about how many of these are related to cash flow and how many to the effort to postpone contracting until the right price is reached.

> "A noteworthy feature of today's market is the increased competition in the services sector"

Fifth is the issue of supply requirements. The same analysts who project a supply shortfall also project a v-shaped path for global demand for petroleum products. This would mean that global growth would be accompanied by a long-term requirement of 1.5 to 2 percent annual petroleum demand growth, based largely on East of Suez demand in the Middle East, South and East Asia. However, a micro-level review of these demand projections does not warrant this assumption. Certainly the major lesson that history brings of demand is that with every price spike has come significant and permanent reductions in demand as a result of difficult-to-track investments in energy savings technologies and as a result of governments liberalising markets and ending subsidies. Demand growth shifts and often reaches tipping points, vividly in the cases of Japan, Korea and Taiwan in East Asia, and in the EU. This will inevitably also be true in both East Asia (China) and the Middle East as projected power generation demand falls to more reasonable levels and where infrastructure is growing for use of other fuels than oil and where the pull on distillate fuels was both unusual and temporary during 2003–08. If demand resumes at a 1 percent per annum rather than at a 2 percent per annum rate, the supply requirements are vastly different. It would under all assumptions be easier to see 850 kb/d of new supply than 1.7 mb/d of new supply.

Sixth is the issue of new sources of supply. It is important to distinguish here between OPEC countries (particularly Saudi Arabia and other GCC and Middle East countries), and some critical non-OPEC areas. If there were a single factor that lay behind the persistent rises in oil prices after 2003 it is in the failure of a handful of OPEC countries to live up to market expectations of their announced increases in capacity. In 1998, four OPEC countries – Iran, Iraq, Nigeria and Venezuela – had a combined production capacity of 12.7 mb/d. The four countries had announced plans to increase their capacity – fully supported by their geology – to 18.5 mb/d by 2008. Instead, in 2008 their capacities had fallen to 10.5 mb/d, 8 mb/d below announced plans. In these circumstances, why would other countries move rapidly to increase their capacities from what they thought they knew in 1998? They wouldn't and in fact it was not until after the disastrous PdVSA labour strike in 2002/03, followed by the increase in domestic disorder in Nigeria and the ousting of Saddam, that firms realised that the market was going to face a supply shortfall that required a dramatic increase in upstream capex.

The amazing aspects of what happened to the supply search after 2003 are important in any assessment of future supply. First, there is now no mistake that Saudi Arabia has massively increased its production capacity and is once again able to balance markets for a time to come. Depending on whether one believes Saudi announcements or takes a more conservative approach the kingdom alone has surplus production capacity today of somewhere between 3 and close to 5 mb/d. Second, there is the extraordinary new focus on finding, delineating and developing upstream potential from deep water, where the major obstacle was not resource nationalism but supply industry drilling capacity. The fact that deepwater sub-salt reserves have been uncovered is what is critical in tapping into this new source of crude oil, whether in the Atlantic Basin, the Gulf of Mexico, the Arctic, Eastern Mediterranean, the Caspian, offshore Australia or Indonesia. The world has focused on Brazil, where the huge Tupi find is now producing oil. Of note, Angola's Sonongol has indicated that Angola's deepwater may turn out to be more prolix than deepwater Brazil, that Exxon has this year increased in deepwater allocations by more than 15 percent, and that both Petrobras and Pemex have announced increased capital deployments on the order of 50 percent at a time when costs are falling. Similarly the unleashing of shale gas in the United States is having a revolutionary result not simply in North America, but also potentially globally.

> "expectations of continued cost savings are leading to the postponement of high marginal cost projects"

Critical to, but exemplary of the conundrums associated with understanding the supply side is Russia. When 2009 began, analysts differed as to the size of the presumed decline in the country's output. Would it be 1–2 percent or 5–7 percent, i.e. would it be a modest 150 kb/d or a robust 700 kb/d? Year to date, however, Russian production has risen and the Russian government now indicates that crude oil output might rise by 2 percent this year. The geology is there; the stimulus from a depreciated ruble is there, and the interplay between companies and the government is pointing to a more benign fiscal regime that could encourage rather than discourage capital expenditures for maintenance and growth.

The lessons are clear. While the supply outlook might be somewhat tighter next year and the year after than might otherwise have been the case, it is unlikely to be as dire as the pessimists forecast; it is unlikely to matter that much given current surplus capacities; and it is unlikely to be as critical to meeting what will surely be a more diminished demand outlook. This doesn't mean there won't be another supply shock on the horizon, but its probability is substantially lower than many now believe.

Pedro Haas and Greg Terzian look at petroleum industry E&P capital spending perspectives

During the summer of 2008 oil prices peaked around 150 US$/b. However many non-fundamental factors one may use to explain this unprecedented level (i.e. speculation, security concerns), it was supply constraints in the face of very strong demand that played a central role in propelling prices sky-high. Now, while oil prices took about five years to rise from 40 US$/b to 150 US$/b, it has only taken them five months to reverse course, and the cause has been a sudden and precipitous decline in demand which has mirrored GDP contraction.

In these circumstances it is easy to overlook the short- and long-term impacts of capital spending on supply capacity reduction. In a long-lead time industry capital expenditure inflexions like the one we are witnessing could have major consequences in the medium and longer term. In summary, the deeper and longer the current recession, the steeper the capital spending reduction of the oil industry and the harsher the supply constraints could be as the global economy recovers.

Demand could once again outstrip supply and cause prices to rise to similar or even higher levels than were experienced last summer. Assessing the current and potential courses for capital investment in the petroleum industry becomes essential to gauge the short- and long-term balance of supply and demand. The IEA makes this point as follows in its March *Oil Market Report*: 'Naturally, slowing economic activity leads to less energy and oil demand, but the obvious flipside to this is that lower prices also lead to a supply response. Normal supply side impacts are being intensified by a credit squeeze, affecting not only investment in new productive capacity, but also operational spending among more cash-strapped companies.'

The *Wall Street Journal* reported on 27 March that 'CERA projected last summer, before the economic crisis set in, that world oil production capacity would rise to 109 MMBD by 2014 from the current 94.5 MMBD. It now says 7.6 MMBD – or slightly more than half of that increase – is "at risk" due to project deferrals or cancellations. CERA said it expects many new projects in Angola, Nigeria, the Gulf of Mexico, deepwater off Brazil, Canada's oil sands and Venezuela's hard-to-extract heavy oil to be postponed or cancelled. The Organization of Petroleum Exporting Countries expects that as many as 35 new projects in OPEC countries could now be delayed past 2013. Most Western oil companies say they are sticking to their investment plans but are slowing down some developments.'

Barclay's Capital has a 2009 non-OPEC production projection of minus 0.56 million b/d, with a call on OPEC crude (plus stock changes) lower in 2009 than in 2008 by 1.24 million b/d.

The Boston Consulting Group meanwhile, estimates that 2009 capex will be 10 percent lower than 2008. This estimate, however, seems low for two reasons: because costs are coming down at least that much on average, if not more, and the Baker-Hughes global rig count is already down more than 30 percent from the average in 2008 (after adjusting for the most recent North America rig counts, which are falling at a very quick rate, as described below).

Drawing a basic comparison between CERA and McKinsey &Co. forecasts, we find not unexpectedly that the largest differences reside in the longer term. CERA's original forecast predicted a capacity growth of 15 million b/d (including biofuels) from 2008 to 2014. By contrast, McKinsey's December 2008 base case estimated liquids capacity growth to be less than 8 million b/d from 2008 to 2014. They further estimate that 2 to 6 million b/d of that growth is now unlikely, depending on the GDP scenario assumed.

> "Demand could once again outstrip supply and cause prices to rise to similar or even higher levels than were experienced last summer"

McKinsey currently estimates an 18 percent, or $81 billion, E&P capital expenditure (capex) reduction globally for 2009 compared to 2008. There can be a much larger percentage reduction from the previously expected 2009 capex, depending on how high one had assumed the 2009 figure would have been relative to 2008, in the absence of the oil price fall and the economic downturn. It is also important to note that the capex reduction announcements from companies are currently at a higher level (30 percent, or $40 billion) than the number we quote above (18 percent), but they are primarily from independents and some national oil corporations that are cutting back more than the global industry due to one or more factors. These include: a weighting towards North America gas, a portfolio of high break-even projects that are now less attractive or uneconomic, and restricted credit market access which is forcing them to live within their cash flows. An informal poll conducted a few weeks ago found that the IOCs are not cutting back much, if at all. However they may be rearranging their portfolios and their capital budgets without announcements. Interestingly, despite CEO pronouncements of 'steady as she goes', the picture gets a lot more nuanced when one speaks to executives one or two levels below the CEO. The larger independents are trying to cut back exploratory but not development drilling, medium and small independents are cutting back development drilling to what their cash flow allows (since much of their development drilling was commercial paper-financed and that market has essentially disappeared) and the larger and better-capitalised NOCs do not seem to be cutting back E&P spending, unless they engage in voluntary re-tendering in order to reduce costs (e.g. Saudi Aramco's rebidding of the Manifa gas project).

McKinsey also estimates that the largest percentage reductions will come from heavy oil (38 percent) and unconventional gas (23 percent), but the largest dollar cuts will come from conventional oil ($28 billion) and conventional gas ($24 billion). From these numbers, it is not hard to expect that the decline rate of the global reservoirs in production will accelerate, an effect that has already been in place in the last few years, as natural decline has shifted from 9 percent in the period 1965–2005, to 10 percent in the period 2003–2007. In its 2008 *World Energy Outlook*, the IEA estimated that the 2030 underlying – or natural – decline rate would accelerate to 10.5 percent, but it is possible that we will attain that decline rate faster than expected, until prices recover and massive capex in mature fields reverses the trend to a certain extent. Another collateral effect of the capex shrinkage has been a 60–70 percent decline of the OFSE (oilfield services companies) total return to shareholders (TRS) since July 2008. Interestingly, although deep-water rig rates have held up much better than land and shallow water rigs, the impact on OFSE company valuations has been similar across the board. For land-based or shallow-water rig companies the impact has come from a drop in demand, and for deepwater rig owners most of the decline is due to a weakening outlook for long-term performance.

In North America, E&P industry capex could be even lower than current estimates. Not only has it fallen by 49 percent in the last 28 weeks (a minus 72 percent compound annual growth rate) but day rates are also down substantially. If day rates and other drilling costs are down 20 percent (probably a conservative estimate, which varies by rig category) and the rig count settles at present levels (45 percent below the average for all of 2008), then drilling expenditures in North America would be reduced by more than 50 percent from 2008. It is also interesting to note that the rig count is falling faster than it did in the past few downturns, though it did fall at a faster rate during the 1986 oil downmarket. In each case, the downturn started at almost exactly the same level (about 2000 active rigs). The 1986 bust was faster (minus 66 percent in 24 weeks and minus 89 percent CAGR for the whole year) than 2009 (minus 49 percent in 28 weeks and minus 72 percent CAGR for the whole year), but the 2009 fall is probably not over yet.

Below are some examples of recent announcements by sizable North American independents:

- Marathon Oil Corp. announced a $5.7 billion capital, investment, and exploration budget for 2009, which represents a 24 percent decrease from 2008 capital spending of $7.6 billion
- Petro-Canada's Board of Directors approved a capital and exploration expenditure program of up to C$4.0 billion for 2009, down significantly compared with C$5.3 billion capital budget in 2008
- Anadarko Petroleum 2009 total capital expenditures, including expensed geology and geophysics (G&G) are expected to be between $4.0 and $4.5 billion, compared with $4.881 billion in 2008
- Talisman, Canada's No. 3 independent oil exploration firm, said earlier in January it plans to shave its 2009 spending program to about C$4 billion from the C$5 billion to $5.3 billion in expected outlays for 2008

Some companies have opted to string out their capital programs, to expand their farmouts, or to bring in joint venture partners with deeper pockets. Chesapeake and its joint ventures with Statoil and BP are good examples. Petrobras itself is considering different ways of leveraging third-party capital and expertise.

"despite CEO pronouncements of 'steady as she goes', the picture gets a lot more nuanced when one speaks to executives one or two levels below the CEO"

In summary, E&P capital programs seem to be holding up proportionally to the size of companies (both NOCs and IOCs), although it remains to be seen whether the 'through-cycle' approach will resist a more sustained GDP downturn. Even though most ongoing major projects that are currently out of the money (e.g. Arctic or deepwater) will be maintained in order to see them through, it is less certain that new projects of the same nature will be funded if the economic cycle does not show signs of turning around relatively soon. Furthermore, it is uncertain whether the oil companies and service companies will maintain the teams they assembled to explore, design and manage these projects should the outlook for the global economy and oil prices deteriorate further later this year and next. These are the most crucial investments from a longer-term supply perspective, since the short-lead time investments, like unconventional gas or mature field re-development, will kick back in as soon as the price prospects recover, with production results quickly following.

A major question mark is the survival of many of the independent companies. Insofar as companies go bankrupt, are bought by others, or shrink their staff count substantially, the industry's capacity to generate and execute projects could diminish. The industry appears to have learned from previous downturns and is not currently shrinking staff numbers across the board, but the temptation (or the necessity) to do so will rise as the down cycle gets prolonged or the global economic outlook further deteriorates. A major and sustained shrinkage of capex, combined with the disappearance of E&P companies as well as oil field service companies, bodes ill for the next uptick in global demand. If there were already doubts about the industry's ability to maintain crude oil production in excess of 95–100 million b/d, a prolonged shrinkage of capex will ensure that even those numbers are harder to attain, thus ensuring a steep price rise in the medium term.

In conclusion, an optimistic view of current capital spending would find that most of the shrinkage has happened in the relatively shorter-lead time opportunities, with a few exceptions like Canadian tar sands. Industry staff levels are holding up and thus capex activity can be revved back up when demand returns and prices justify additional spending and activity. Under these conditions, even though capex has fallen and production has declined, longer-term production and reserve muscle has not been lost.

A more sober assessment, however, would indicate that much hinges on a few major areas: Canadian tar sands, Brazil pre-salt and some key OPEC projects. A more stubborn downturn could well show the industry taking measures that would be harder to reverse: staff reductions, long-lead time projects delays or cancellations, a general redeployment of cash to shorter-lead time investments.

The industry seems to be resilient and doing well so far, even under current difficult conditions. But the outcome is far from certain and hinges on the next 12 to 18 months. Shareholders, Boards of Directors and Ministers will become more conservative as time wears on, if the global economy does not show signs of sustained and solid improvement.

Post scriptum: this article was written before the oil company quarterly earnings announcements. In the event the results were significantly lower than had been assumed, which has caused some IOCs to announce capex reductions (i.e. BP), some to say they are thinking hard about how much to invest (Shell's Jeroen Van de Veer said 'To invest or not to invest, that is the question'), and others to remain unchanged (Chevron and ExxonMobil).

Ali Aissaoui assesses the shrinking MENA energy investment outlook

By throwing the world's economy into deep recession, the credit crisis has precipitated the collapse of oil markets and prices. For the Middle East and North Africa (MENA) region, whose economy relies predominantly on petroleum, one crisis has followed on the heels of another. The sharp contraction of credits has been compounded by a dramatic fall in corporate and government petroleum revenues. At the heart of the new challenges facing the region, as it moves to mitigate the impact of this dual crisis, is how to maintain its capacity to make a vital contribution to the world's energy supply and fulfill its growth potential.

It is worth noting in this context that while the MENA region holds 67 percent of the world's proven reserves of crude oil and condensate, it only accounts for 38 percent of global oil output. Similarly, it holds 46 percent of proven natural gas reserves, but contributes to only 19 percent of total gas output.

In times of crisis, however, expediency is a necessary principle of action. MENA policy makers and project sponsors, who until recently had been scaling up their energy investment strategies despite unrelenting rising costs, have had no choice but to drastically scale them down. As a result, an increasing number of projects have been made redundant. In this commentary we assess this downtrend and the resulting shrinking investment outlook. The assessment derives from our periodic rolling five-year review of investments along the oil and gas supply chains. For reasons made apparent in the methodology section below, we extend our analysis to the uncertainties surrounding trends in project costs and the challenges posed by severe funding constraints, as both have a profound impact on the outlook.

A Project-based Review

Our review of investments relies on a real world project-based approach. The main input variables are upstream, midstream and downstream oil and gas projects. The downstream is extended to include petroleum-based petrochemicals as well as oil- and gas-fueled power generation. The review, which identifies the main steps in project life cycle, takes in projects that have apparently secured a final investment decision (FID). One key attribute of this framework is that the usually explicit determinants of investment – demand and prices – are implicit. In contrast, project costs and funding availability are treated as explicit inputs.

It should be noted that since the onset of the credit crisis this framework has been amended in an attempt to reflect the greater uncertainties surrounding the outlook. As a result, projects abandonment are more closely monitored. Since project sponsors seldom announce shelvings or postponements, we infer these from reports by the trade press and from our own insights into the industry. Futhermore, our findings are now summarised into two categories: the potential capital investment, which takes in all FID-backed projects, and, deducting the projects shelved or postponed (beyond the five-year review period), the actual capital investment requirements. Lower potential capital investments result mainly from the anticipation of lower cost of projects; whereas lower actual capital investment requirements factor in anticipated lower demand and prices and the expectation that, despite assumed lower costs, projects may no longer be economically and financially viable.

Shrinking Outlook

Figure 1 summarises and illustrates the key findings of our annual rolling five-year reviews. It shows that the steep upward trend in MENA energy capital investments over the last six reviews has now reversed. Indeed, the current preview for the five-year period 2010–14 points to lower capital investment potential. It also confirms a further drop in actual capital requirements. At the present time, we expect the capital investment potential to decrease by 15 percent, to US$550 billion, and the actual capital requirements to fall by 30 percent below this potential, to $385 billion.

Closely reflecting the distribution pattern of crude oil and natural gas reserves in the region, two-thirds of the energy capital investment potential continues to be located in five countries namely Saudi Arabia, Iran, Qatar, UAE and Algeria, with a little more than half this potential in the first three (Table 1). In Saudi Arabia, potential capital investments have come down to $139 billion. Shelved or postponed projects are estimated at 21 percent of this potential, mostly in the downstream sector. Iran has maintained its second place in the new ranking with US$82 billion. However, about 36 percent of this potential may have been shelved or postponed as international sanctions continue to hamper the industry. In Qatar the potential capital investment is now estimated at US$62 billion. In this country, we further assume that the moratorium on further development of the North Field gas reserves will not be lifted during the review period. As a result, shelved and postponed projects are put at an even higher rate of 43 percent of potential.

Table 1: Main country distribution of energy investment ($ billion)

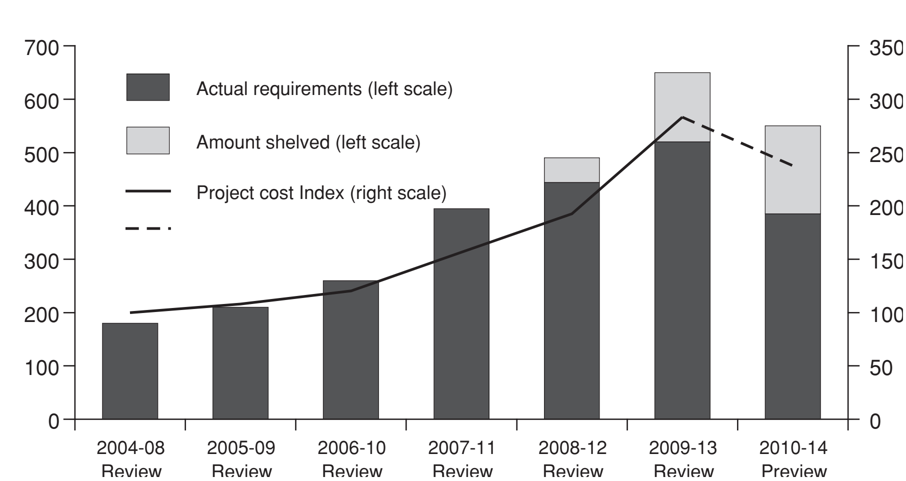
	Revised potential	*Actual requirements*	*Percent shelved*
Saudi Arabia	139	110	21%
Iran	82	52	36%
Qatar	62	36	43%
UAE	51	43	17%
Algeria	38	31	20%
Sub Total	372	271	27%
Total MENA	550	385	30%

Source: *APICORP Research*

Cost Uncertainties

As indicated by the evolution of our index (Figure 1), the cost of an 'average energy project', which has risen almost three times since our first review in 2003, is expected to come down. The 15 percent downward trend underpinning the preview for the period 2010–14 is, however, tentative. The extent that such an overall trend is predictable and reliable is examined next by analysing the structure of project costs and the likely evolution of their main components.

Figure 1: Rolling 5-year reviews of MENA energy investments



The most preponderant element in project costs is the price of engineering-and-procurement (EPC), which represents 70 to 80 percent of the total cost of a typical large-scale energy project. A thorough and insightful analysis of the pricing of project risks is given in E.W. Merrow, 'The Cost of Project Risks: Contracting for Large International Projects in the New Era', Independent Project Analysis, Inc, 2006. Using the criteria outlined there the key contributing cost factors to EPC are the prices of factor inputs, contractors' margins, and project risk premiums when assumed by contractors. To these three factors we have added our own, which is the cost of 'excessive largeness'. Until recently, in order to cope with unrelentingly rising costs, the major MENA project sponsors sought to increase the scope and/or scale of their projects as a way to lower unit costs and maintain an adequate return on invested capital. However, evidence from trade press reports suggests that the economies of scope and scale of some large projects in the region (Petro-Rabigh and Ras Laffan complexes are the most frequently cited cases) are being offset by the diseconomies of the resulting complexities, particularly in terms of delay costs and compensation to product offtakers.

Reflecting the above components, Figure 2 shows a typical cost structure of a large-scale energy project. Prices of factor inputs (steel, copper, cement, and so on), which represent some 45 percent of a typical project cost, are expected to decline but at a pace more in line with that of major industrial materials and equipments than of raw commodities. Contractors' margins are also likely to drop slightly unless the ongoing dual crisis leads to greater consolidation within the engineering and contracting industry. (According to IPA, in a direct communication to the author, although it is not unreasonable to expect consolidation, this is unlikely to affect Tier-1 companies. These ten top EPC companies already control three-quarters of the process industry market and a greater share of the market for large-scale projects.) In contrast, as the global credit crisis has forced an up-pricing of risk, we should expect project risk premiums to remain relatively high. The cost of excessive largeness is likely to disappear altogether with the shelving of most complex projects. Last but not least, 'others' denotes a miscellaneous component whose costs tend to mirror the relatively high rate of general-price inflation in the region. Hence, despite the observed drop in the cost of the most predominant factor inputs, it is hard to infer how far and how long the overall cost trend is likely to be down, when combining all components.

Funding Challenges

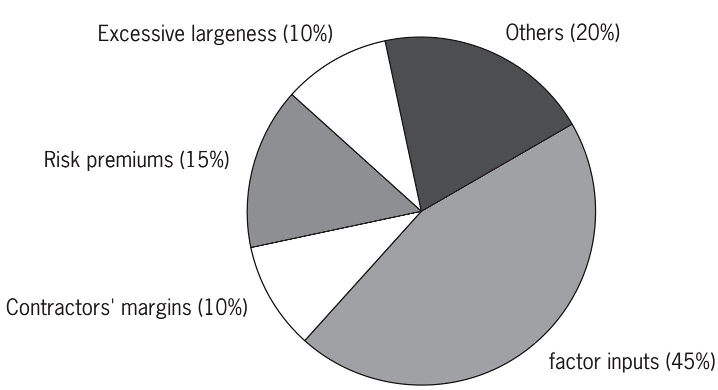
Cost uncertainties have been compounded by a marked shift in projects' capital structure. In a context of severe credit and oil market crises, this shift has exacerbated the dilemma facing corporate financing policies.

Even in keeping with the industry's normal standard, we have witnessed a trend towards a more equity-oriented capital structure. The industry normally uses retained earnings (internal equity) to fund high risk, high return upstream and associated midstream activities. In contrast, it tends predominantly to use debt and external equity for low risk, low return downstream activities. Based on most recent deals, the average equity–debt ratio in the oil-based refining/petrochemical sectors has been 35:65. The ratio in the gas-based downstream sector has been 40:60 to factor in higher risks of feedstock availability. In the power sector, the ratio has been reset to 30:70 to reflect lower leverage in independent power/water projects. On this basis, the resulting weighted average capital structure for the whole oil and gas supply chain is likely to be 57 percent equity and 43 percent debt for the period 2010–14. This compares with the equity–debt ratios of 54:46 found in the 2009–13 review and 50:50 in the 2008–12 review.

> "The most preponderant element in project costs is the price of engineering-and-procurement"

Whatever the trend in capital structure is, however, achieving the needed amount and mix of equity and debt will be considerably more challenging. On the one hand, we have estimated that a prolonged period of low oil prices below $60–80/bbl will affect project sponsors' ability to self-finance upstream investments. On the other hand, funding prospects for the still highly leveraged downstream will be even more daunting. (The $60–80 band lies at the confluence of the economic price needed to develop frontier projects and the fiscal price needed to meet oil producers' realistic requirements for revenues. (This is developed in my article in *MEES,* 6 April 2009). The annual volume of debt of US$33 billion for the next five years, which results from the actual capital requirements found in the current preview and the likely capital structure highlighted above, remains comparable to the all-time annual record of US$39 billion achieved in the loan market prior to the onset of the credit crisis. Nowadays, such amounts of debt can hardly be met owing to lesser credit availability, higher costs of borrowing and tighter lending conditions. And this is despite the move by some MENA public investment funds to tap governments' net savings and step up their lending and involvement in the local debt market.

Figure 2: Typical cost structure of a large-scale energy project



Conclusions

To cope with the global credit and oil markets crises, MENA energy policy makers and project sponsors have had little option but to reassess their investment strategies and scale down projects portfolios. As a result, the uptrend momentum achieved in recent years has reversed. Our current preview for the five-year period 2010–14 has revealed a lower potential capital investment, which stems largely from expected reduced costs of projects. The preview has also confirmed a further drop in actual capital requirements as a consequence of the continuing shelving and postponement of projects that are no longer viable and fundable. How quickly and at what cost these projects will be brought back when the investment climate improves depends very much on how the engineering and contracting industry is affected in turn and the ways it will itself be responding.

Letters to the Editor

LNG Trading: Overview and Challenges

Dear Editor,

I found the article by Wietfield and Fenzl to be a comprehensive and thoughtful overview of the LNG industry. However, I was somewhat surprised that they did not explain a major change that has been developing in the structure of LNG trading.

The traditional long-term contract commonly linked a specific supply source with a specific customer, often utilising dedicated tankers. It could thus be described as a 'fixed destination contract'. It was clearly ill-suited to an emerging world in which destination flexibility permits shippers to divert cargoes to those markets with the strongest prices. The resulting flexibility enables the price arbitrage, which now transmits price signals between gas market regions.

The authors do discuss the emergence of short-term trading and its role in price arbitrage, but they do not even mention 'self-contracting' or 'supplier aggregation'. This new pattern is becoming an even greater source of destination flexibility, particularly in the Atlantic Basin. In traditional long-term contracting, the old adage, 'The buyer takes the volume risk and the seller takes the price risk' led to take-or-pay obligations for buyers and price escalation clauses for the sellers. The authors mention the oil price linkage in contracts – JCC in Northeast Asia and oil products on the European Continent. But by lumping the gas market indicators – Henry Hub and NBP – with the oil escalators, they fail to differentiate between the way these two types of price escalators actually function.

In the liberalised gas markets of North America and the UK, gas-to-gas competition is supposed to set gas prices and prices are frequently decoupled from oil price levels. In these markets, commodity trading has largely replaced long-term contracting for domestically produced gas. It is increasingly difficult to find customers in these liberalised markets who can commit to the volume obligation without protecting themselves with a gas market price indicator, such as Henry Hub or the NBP. But since buyers can so easily resell unwanted volumes without loss in a liquid trading market, their risk is reduced. Risk has migrated upstream to the sellers. The response of sellers has been to take the contractual obligation on themselves – self contracting – and market directly to ultimate customers.

Nigeria's Bonny project illustrates the difference in the two approaches. Trains 1, 2 and 3 were traditional contracts between the joint venture, NLNG, and European customers. But both Shell and Total, venture partners in NLNG, have contracted for volumes from the venture out of Trains 4 and 5 and are free to take their equity LNG wherever they see fit. This, like short-term trading, is destination-flexible and facilitates price arbitrage. My estimates suggest that self-contracting is at least as large as short-term trading.

Yours Sincerely,
James T. Jensen
Jensen Associates

Dear Editor,

I enjoyed the article 'LNG Trading: Overview and Challenges' in the February 2009 issue but would like to add a couple of important points.

On LNG supply it should be noted that we are currently at the start of a significant ramp-up in global LNG supply with some 120 billion cubic metres per annum (bcma) of liquefaction capacity coming on stream over the next three years. This compared with LNG supply for 2008 of some 240 bcma, is a 50 percent increase in LNG availability and represents some 20 percent of Europe's current annual natural gas consumption.

At the time these LNG projects achieved financial approval (circa 2004) the expectation was that the regional natural gas markets of North America, Europe and Asia Pacific would remain 'tight' for the foreseeable future, i.e. demand growth for LNG imports was safely assumed.

Two factors have challenged that assumption. Firstly the ongoing global economic downturn has reduced expectations of demand growth for gas in the industrial and residential and commercial sectors. Secondly the unexpected but highly successful exploitation of 'unconventional' gas in North America has reduced expectations of LNG import requirements in that market.

However, once an LNG project is completed its effective short-run marginal costs are very low – in large part due to the contractual segmentation of the supply chain. The costs saved by 'shutting-in' LNG supply may indeed be confined to the variable operating costs of the upstream field.

The question of 'where all this new LNG will go' has a number of dimensions. Clearly it will compete with other sources of natural gas and probably with other fuels.

The most accessible markets for new 'flexible' LNG will be North America and the UK as re-gasification capacity is in place and, given the nature of these liberalised markets, LNG can be sold without a contract with intermediaries or end users. As prices are lowered here, one might expect a higher cost domestic gas production to be shut-in. It is noted that in North America the number of operational gas drilling rigs has fallen by 40 percent since October 2008. A price floor may be provided by the displacement of coal in the power generation sector, however due to the nature of the North American power sector regulatory framework the physical scale of substitution may be less than might be imagined.

In continental Europe the prospect of competition between LNG pricing at the margin off Henry Hub and oil-indexed long-term contract pipeline imports is a real one. This would become a significant issue were new entrants able to access sufficient market share to leave incumbents unable to sell-on their pipeline import 'take or pay' contractual volumes. It was this situation in the UK gas market in the 1990s which was key to undermining the status quo and to the establishment of a liberalised traded market. Will this play out in continental Europe?

What is at stake here is the preservation of the oil-indexation framework much cherished by supplier countries and importing incumbents despite the fact that with true burner tip competition between gas and oil products very much a feature of a by-gone era, there is little if any rational justification for its perpetuation. Depending on the envisaged duration of the LNG supply surge and the economic downturn, it might be expected that oil indexation will continue but only with a degree of painful compromise on take-or-pay enforcement.

Looking at the shape of the longer-term LNG supply outlook the situation may well repeat itself post 2015 when Australia and Nigeria together create a second supply wave.

Howard Rogers
Senior Research Fellow, OIES

Sir

I read with interest the article on LNG Trading by Axel Wietfeld and Niels Fenzl. The intensification of the global recession since the article was written brings the issues further into focus as a short-term surplus in gas markets becomes ever clearer.

The global natural gas industry is now suffering from a 'triple whammy': a sharp and untimely reduction in gas demand caused by the global recession; growth in North American gas supply brought about by the unexpected and sudden emergence of shale gas; and the long anticipated surge in global LNG supply. As a consequence a global gas supply bubble has emerged.

Is this the seismic shock that is required to bring change to the LNG business model and accelerate a move toward a more freely-traded spot market? Or, on the contrary, does this push us back toward the tried and tested formula of rigid bilateral long-term contracts – a rush to safety? Neither the evidence nor logic point in a single direction, but we can suggest the following:

The value of dedicated markets is returning. In a world of surplus and poor economic performance, those players who can offer LNG sellers secure identifiable market demand and who are creditworthy are once again of high value. Open supply portfolios of LNG look less attractive in a long market.

Both producers and buyers will find their portfolios out-of-balance. The decline in gas demand means that some buyers will find themselves long; some producers will find they hold excess supply. The imbalance between portfolios will precipitate more trading, at least among the traditional core players.

The value of the LNG midstream is eroding. Surplus capacity in shipping, re-gasification, possibly even liquefaction, will lead to downward pressure on the valuation of these assets. For example, LNG spot charter rates have halved and re-gasification options in the Gulf of Mexico are said to be widely available.

The rationale for entry into the LNG midstream as a business in its own right is much reduced – where is the advantage in controlling shipping or re-gasification? A rapid move toward global price convergence has undermined the concept of portfolio optimisation. With abundant spare re-gasification and shipping capacity, the concept that re-gasification provided a value proposition – or at least a competitive advantage – in accessing supply is losing its force (with some exceptions, to be sure). It therefore makes little sense for producers to invest additional capital in the midstream unless essential to support upstream development. For most producers, the midstream was usually a means to an end, the monetisation of gas, and not an end in itself.

The financial crisis will require greater direct equity investment and less leverage. Under these circumstances, E&P companies will need to release capital from lower return segments in the chain – read midstream gas assets –in order to focus on the higher return of upstream production.

Few institutional players – either sellers or buyers – have an interest in a radical shift to a short-term traded market, so they will look to ride out the short-term storm. Whether they succeed will depend, in large measure, on the length of the recession. Hold on to your hats!

Michael Stoppard
Managing Director, CERA

European Union Energy Policy

Dear Editor,

Key points made in David Buchan and Giacomo Luciani's articles on EU energy policy have been magnificently illustrated during the weeks after their publication, in particular by the choice of projects for the Commission's Euros 4bn stimulus package.

Buchan's observations about the 'astoundingly complacent Gas Security Directive of 2004' and how 'many member states dozed on', after the 2006 and 2007 interruptions of Russian gas supplies only serve to highlight crucial weaknesses in EU energy policy making: member states have fundamentally different levels of vulnerability; some of the most vulnerable countries are not European

Union members – or even Energy Community Treaty signatories.

The Gas Security Directive is a toothless document because that was what the current member states and their gas industries wanted. As Buchan notes, it was adopted the month before ten new member states joined, before Bulgaria and Romania were even in accession negotiations and before the Energy Community Treaty was even thought of. The impact of the January 2009 crisis on the old member states was negligible and even positive – their gas companies were able to sell gas from their storages at high prices, safe in the knowledge (because they knew that oil prices had fallen) that they would be able to buy gas back at lower prices later in 2009. Countries such as Italy learned much from the 2006 crisis and subsequently spent substantial sums on storage and interconnection. The most severe impact on the crisis was on new member states (Bulgaria and Romania) and non-member states (Bosnia, Serbia) which, even if they had been concerned about the potential impact, had no funds to make the necessary investments.

Having recognised that the problems were concentrated in south east Europe, and understood that the parlous state of the Ukrainian economy meant that such events could easily recur, it might have been expected that Brussels would concentrate available funds on the problem region. Sadly, the stimulus package shows otherwise. After considerable infighting from the initial distribution (detailed in Luciani's article), the outcome is shown in the table below. Following the most serious gas security crisis – and one of the most serious energy security crises ever experienced – in Europe, gas interconnection, storage and diversity measures received Euros 1.4bn out of a total of 4bn. Even more extraordinary, projects in the countries in central and eastern Europe which had been most seriously affected by the crisis received a total of Euros 310 million. By comparison, the reinforcement of the network on the Africa-Spain-France axis received 200 million as did a new Franco-Belgian interconnector. While there is certainly a case for spending money on these projects, should they really have had a higher priority than increased spending in Central-Eastern Europe? And while there is also a case for spending money on Scanled (Poland, Demark, Sweden), Nabucco and GALSI, could these projects not have waited a little, while more urgently needed interconnections were prioritised? Even more controversially, could more funds have been taken away from other spending categories on grounds of urgency?

PROJECT TYPE	*Budget (Million Euros)*	*LOCATION*
Electricity interconnectors	910	
Small Island projects	15	
Offshore wind projects	565	
Carbon capture and storage projects	1050	
Gas Interconnectors	1440	
Including:	200	Nabucco pipeline
	100	ITGI Italy-Greece
	150	Poland-Denmark-Sweden
	80	Poland LNG
	30	Slovakia-Hungary
	40	Slovenia
	45	Bulgaria-Greece
	30	Romania-Hungary
	35	Czech Republic storage
	80	13 (mostly) new member states reverse flow infrastructure
	20	Slovakia-Poland
	20	Hungary-Croatia
	10	Bulgaria-Romania
	200	Africa-Spain-France
	120	Italy-Spain GALSI
	45	Spain
	35	Germany-Belgium-UK
	200	France Belgium

Source: Council of the European Union, *Presidency compromise proposal for financing of the infrastructure projects put forward by the Commission as part of the EERP*, Brussels 7848/1/09, 20 March 2009.

Of course we all know the answer to these questions: every member state 'had to get something', and Commission policy had to be seen to be addressing the different elements in the 20/20/20 policy framework. But geographical and policy even-handedness has surely been the enemy of urgent action on security of supply. An opportunity has been missed to demonstrate 'solidarity' with non-member states such as Serbia and Bosnia by spending on urgently needed gas interconnections.

This kind of decision-making leads to cynicism, particularly in new member states, about the balance of priorities in EU energy policy. It may also create some embarrassment if there is another Russia–Ukraine crisis over the next year – an event that (unfortunately) cannot be ruled out. In this event, Buchan's benchmark of a 'D' for EU performance on security of supply may appear overly generous.

Jonathan Stern
OIES

The Oil Price Crises of 1998–9 and 2008–9

Robert Mabro

Oil prices collapsed beginning in late 1997 from an average of $17 per barrel (dated Brent used as a wide reference at the time) to a low of just above $10 per barrel. This low level, which was reached as early as March/April 1998, held with some fluctuations, until early 1999. The fall was of the order of 40 percent. The impact on the export revenues of oil-exporting countries was severe. The base price of $17 per barrel that has been characteristic of oil price movements since 1989 was not very rewarding. A 40 percent fall from this level involves a greater percentage fall from net unit revenues since that number, equal to price minus unit costs, is smaller than the per barrel price. To illustrate, assuming that average per unit cost was about $1.5 per barrel at the time, per unit revenue at $17 per barrel would have been $15.5 per barrel. A $7 per barrel price fall would have reduced revenue by 45 percent.

The oil-exporting countries felt economically vulnerable to the oil price fall, and this prompted them fairly quickly into action, but success in reversing the price movement was long delayed.

In 2008, oil prices (taking the WTI futures price as a reference) began to fall in early July from a peak of about $146 per barrel. It is wrong to measure the fall (or rise) of a price taking for the base a trough or a peak. What will do for exciting news headlines is of no use analytically. The fall in oil prices from the $100–145 per barrel range that obtained in the first half of 2008 to the $35–50 per barrel range recorded in the period November 2008 to April 2009 represents (taking the mid-points of these two ranges) a fall of about 65 percent. This is a much larger percentage fall than in 1998–9; but an oil price in the $40–50 per barrel range in 2009 is less damaging economically for many oil-exporters than the $10 per barrel price was in 1998–9. This does not mean, however, that most of them would not prefer a higher price as indicated by the King of Saudi Arabia when he suggested that $75 per barrel would be fair, efficient and therefore desirable.

The 1998–9 and 2008–9 crises differ in several respects. A most important difference relates to the causes of the price collapse. To be sure, there was a common occurrence: in both cases: world oil demand was falling. In the first episode, this began to happen in late 1997 and continued under the impact of the Asian economic crisis. In the second episode, oil demand began to fall in the USA at the beginning of 2008, if not earlier, largely in response to the rise of the domestic prices of petroleum products. Later on, the recession caused by the credit crunch and the failure of a number of financial institutions led to a fall in either the level or the rate of growth of oil demand in other countries.

The difference between the two episodes lies, however, in other causes: the pursuit of a price war in 1998 and the hubris that swept financial markets starting some time in 2004 if not earlier.

In 1997, Saudi Arabia and other OPEC Member countries were upset by the output maximisation policy pursued (or claimed to be pursued) by PdVSA, the national oil corporation of Venezuela, at a time when world oil demand was either stagnating or falling. At an OPEC Conference of oil ministers held in Jakarta late in 1997, Saudi Arabia persuaded other member countries, apparently without great difficulties, to increase the then current production quotas by 10 percent.

The argument used was that the International Energy Agency (IEA) has been underestimating world oil demand and overstating the volumes of non-OPEC production for reasons that anybody can guess. This had been going on for a long time by then. The result was that the call on OPEC was underestimated and this seemed to justify the proposed increases in quotas. Some commentator later quipped: ‘strange that the ministers could not see the Asian economic crisis by looking down from their hotel windows in Jakarta’.

Almost immediately oil prices dived down. This alarmed Mexican officials who saw, before anybody else, the adverse implications for the economies of oil-exporting countries; it alarmed the Venezuelans who began to realise that their boasts about maximising production have heavy costs in terms of oil revenues; it alarmed the Saudis who were seeking a way to retrieve the situation.

Because the problem was essentially an internal OPEC affair the market naturally focused on OPEC – the internal strife and the attempts to solve it; the relationships between Members, not only Venezuela and Saudi Arabia, also Saudi Arabia and Iran; and on the fundamental policy issues of production programming and the perceived degree of implementation of such decisions. And because this was an OPEC internal affair the recourse to oil diplomacy between member countries and other oil-exporting nations occurred from an early stage.

As usual, the market indulged in extreme scepticism. Successive decisions by OPEC and a few non-OPEC exporters announcing production cuts were met with disbelief, so much that every such decision in 1998 was followed by a price fall. Furthermore, there was a lack of trust between protagonists – Saudi Arabia and Venezuela, Iran and Gulf Countries. Active mediation by Mexico, despite some successes, was also met with disbelief or outright dismissals.

The belief that the market was flooded with supplies moved the term structure of futures prices into a contango from August 1997. The difference between the price of the first and second months futures contracts was not very high by current standards. They did not reach $0.20 per barrel until the end of November 1997; by March 1998 the differential reached on some days the unprecedented level of $0.42

per barrel. At that time, a differential of $0.18–0.20 per barrel was sufficient to provide an incentive to buy physical oil, add it to inventories, and sell a futures contract at a $0.20 (or more) higher price than the spot.

Inventories were built up, not as much as stated by the proponents of the 'missing barrels' myth; and an inventory build-up results in falling prices as this is interpreted without qualifications as signifying excess supplies in the sense that exporters are deliberately flooding the market.

The oil price initial fall and subsequent stagnation at low levels lasted throughout 1998 and until March 1999. A market almost entirely focused on the internal relationships between OPEC Members was by March 1999 convinced that OPEC unity had been restored by two events: an agreement between Iran and Saudi Arabia reached by the respective foreign ministers of these two countries in January 1999, and even more crucially by the election of Hugo Chávez to the presidency of Venezuela. Furthermore, the output cuts that the market had ignored for so long had at last begun to be seen biting, so long is the lag between the actual impact of fundamental economic forces and the perception of this impact. As often in the history of oil political and economic forces combine to deliver an outcome.

What has been happening in 2008–9 and will continue to unfold in the months to come has different causes but some common features in the outcome. OPEC was not initially at the centre of the story despite accusations against it by uninformed leaders of some OECD countries. The relentless oil price rises on the futures exchanges were essentially a financial phenomenon. Investors had accessed to huge volumes of money (either borrowed or owned) seeking high returns. Commodity markets appeared to be attractive because of a belief that the demand for oil and other fuels, and for grains, was rising due to fast economic growth in the emerging countries while supplies were constrained. When this is the case prices are bound to rise. These views got strong support from banks that produced bullish forecasts and were eagerly followed. After all the leaders of financial markets cannot but be financial institutions.

Optimisation of portfolio strategy also played a role leading to price rises. At some point commodities seemed more attractive than equities or bonds. Pension funds decided, rationally no doubt, to hold commodities instruments in their portfolios. This increased the demand for these instruments pushing their prices up.

Those involved in these financial markets argued forcefully that the oil price increases that continued to obtain until early July 2008 were entirely due to the fundamentals of supply and demand. Economists who are not specialised in oil felt very comfortable with this explanation. After all supply and demand – the economic fundamentals – are the basic tools of their trade. But 'demand for what' is the question that is rarely asked. Is it the demand for a physical barrel of oil or for futures contracts or other derivatives denominated in oil?

The futures oil price (WTI on the NYMEX) rose from $100 per barrel to $146 per barrel in the first six months of 2008 despite significant falls in US oil demand and the absence of any evidence of contemporary supply shortages. The alleged reason for this price movement was expected future supply tightness. The subsequent 65 percent fall in oil prices was attributed to fall in demand but the view previously held that supplies will be tight in the not-too-distant future seems to have been suddenly forgotten insofar as the front market is concerned.

The question in 1998 was: How do you re-establish trust among OPEC Member Countries? The question today is: How do you mend a pricing system prone to huge destabilising swings?

OPEC naturally has decided to intervene with production cuts to raise oil prices from the low levels reached. We enter here in the familiar territory of market scepticism. The initial market reaction was to dismiss both the decision to cut production (the views being that either the proposed cuts are too big and therefore unrealistic, or too small and irrelevant) and the likelihood of strict implementation. One may ask: Why should implementation, to be effective, correspond exactly, up to the last barrel, to the production quotas agreed by OPEC member countries? There are cases when the production agreement overstates the volume that needs to be cut. And it is important to recall in this context that most exporting countries tend to supply, within the limits of their capacity, according to the demands of their customers.

This should balance supply and demand on the assumptions that oil companies will not consistently nominate more than they will eventually require and that producers will not encourage buying with aggressive price cutting competition. The catch, however, is that companies' nominations may include a demand for inventory build-up in response to a contango in the term structure of futures prices.

In 1998 the term structure of oil prices was in contango. In 2008/9 the differentials between the first and second month WTI futures contracts have tended to be in the order of $2.0–2.5 per barrel. This is more than adequate to induce the building up of inventories and in turn to depress prices. A build-up has taken place in the Cushing Oklahoma region, a critical location where WTI crudes and Canadian crudes are supplied. There are reports that some oil companies and trading houses are chartering VLCCs to use them for storage. This complicates OPEC's task as it did in 1998 because drastic production cuts will be needed to turn the term structure into backwardation.

In both episodes a central issue relates to the interface between OPEC and the oil market (by which I mean these places where reference prices for oil in international trade are determined). The conventional policy consists in signaling to the market through production cuts OPEC's displeasure with the level or the falling tendency of prices. A more direct policy would be to define a preferred price (that can be changed according to circumstances) and defend it with automatic production adjustments. This idea was advocated ten years ago but has not gained the policy makers' favour.

In other words, a price, rather than a production policy, is the relevant instrument to achieve a price objective. Common sense supports such a proposition. There are difficulties, of course, in switching from one type of policy to another. These difficulties can be exaggerated however. OPEC fears that a price policy will subject it to criticisms about causing price shocks. The sobering thought is that OPEC was the object of virulent attacks by the UK prime minister, Gordon Brown, and the Australian prime minister among others for having caused prices to rise to $100–145 per barrel when an elementary knowledge would have informed leaders that the reference prices for oil in international trade are determined in futures exchanges in which OPEC countries do not participate.

OPEC will be blamed whatever it does. This being the case, why not adopt a pricing policy that has the merit to address *directly* the price objective? The additional advantage is that OPEC will be more able to stabilise prices than futures markets where volatility is the name of the game.

Energy RD&D: a much needed clean tech stimulus

Marianne Haug

Can an industry that spends about 1 percent of net sales on Research, Development and Demonstration (RD&D) transform our energy system? Can an industry with the lowest RD&D intensity of any high tech sector tackle the clean technology investment challenges of the coming decades – 1 percent of GDP according to the Stern Review of 2006 or up to US $540 billion per year to 2030 according to the 2008 IEA WEO estimates?

The facts are well known: industries that transformed our economies – telecommunications, information technologies, pharmaceuticals or biotechnology spent consistently 10–15 percent of net sales on RD&D. The RD&D intensity of the automobile industry that focused up to now more on incremental than radical innovations averaged about 4–5 percent per year.

The comparable figures for the energy sector are telling: oil and gas companies in OECD countries spent 0.35 percent of net sales per year on RD&D over the past five years. The fifteen top RD&D spenders among the PFC Energy fifty companies spent a mere US$10 billion on RD&D in 2007. In absolute terms, Royal Dutch Shell spent the most – US$1.2 billion followed by Exxon Mobil at US$814 million, TOTAL at US$800 million and Schlumberger at US$728 million. RD&D intensity in the oil and gas sector is highest among the service companies: Schlumberger and Baker, Hughes averaged 3 percent per year compared to Halliburton at 2 percent. The year 2007 showed a marked increase in low carbon RD&D of oil and gas companies mainly for CCS, hydrogen/fuel cells, and biofuels, but figures vary greatly among firms. The present shake-out of clean technologies portfolios will show who among the oil and gas companies will integrate clean technologies in its core business in the medium term.

The steady decline of private RD&D spending for electric utilities is well documented for Japan, Europe and the USA. Some suggest that the liberalisation process affected the firms' willingness to invest in technology and innovation. The RD&D intensity of Japanese utilities dropped to 1 percent per year by 2002 and has hardly recovered. The RD&D intensity of the European utilities dropped to as low as 0.7 percent in 2005. The absolute RD&D spending of European utilities remained relatively constant: the top twelve European utilities invested yearly EUR 1.0–1.2 billion over the 2003–2007 period. This picture is changing as a majority of European utilities now invest proactively in clean technologies – wind, CCS, nuclear and other renewables and associated RD&D. The utilities industry relies to an important extent on the innovative capabilities and investments of its suppliers. The RD&D intensity of the European manufacturers of electrical equipment and components averages 6 percent per year and that of the non-EU manufacturers about 3 percent per year.

How do these figures fit into the overall picture? The IEA estimates in 2009 that global corporate energy RD&D is in the order of US$40–60 billion per year. Clean energy RD&D not including nuclear expenditures may account for as much as US$10 billion according to New Energy Finance (2009). In contrast, the public energy RD&D of IEA countries dropped by a factor of two in real terms over the past 25 years. It was a mere US$12.1 million in 2007 or about 15–20 percent of total energy RD&D expenditures.

These trends and figures are a real cause for concern: innovation is at the heart of improving existing technologies, at replacing traditional ones and bringing about systemic or regime changes. Innovation and investments toward a clean energy transition by the private sector will not happen unless the public sector addresses the two fundamental market failures: first, energy prices need to internalise environmental and energy security externalities; and second, distortions in the incentive to innovate, the 'technology' market failure needs to be reduced or eliminated.

Much has been written and done about the first market failure. Investors value reliable price signals and a stable regulatory framework. Carbon pricing, feed-in or premium tariffs for low carbon technologies, targets, standards and public procurement are paving the way in many countries. The Kyoto Protocol, the EU-ETS, the EU Energy and Climate Package, country/state specific low carbon targets and policies and now the reengagement of the USA in the climate negotiations on the way to Copenhagen 2009 improved the enabling environment and stimulated major investments in wind, PV and biomass to name a few. We have come a long way, but the recession and strains on private capital markets have brought home the inherent risks and fragility of the system. With many low carbon technologies not yet cost competitive or still in the demonstration stage, EU allowance prices in the EUR 10–30 t/CO_2 range, and global emissions reduction targets still uncertain, incentives are insufficient to catalyse the magnitude of clean energy investments needed.

Much less has been written or done about the 'technology' failure in the energy sector. Three major, additional factors distort the incentives to innovate for private companies

First, knowledge spillovers create a gap between the societal return of an RD&D investment and the actual value captured by the innovating firm. Differences as high as 20–30 percent have been reported across some sectors. The gap is particularly pronounced for energy investments that typically have long lead and life times. Innovation decisions of private firms are based on risks and profit concern, while governments need RD&D to meet longer-term energy and climate change objectives.

Second, the lock-in effect of technology choices once made result in path-dependence for future investments. They are not only effective barriers for individual new technologies but can lock a country into an entire 'technology regime' with well-established practices, institutions, infrastructures, skills and corporate cultures. Gregory Unruh was the first to point out that our present fossil-based energy system constitutes such a 'regime lock-in' and decisively hampers the transformation towards low carbon energy. Such regime lock-in goes beyond cost competitiveness, subsidies, or maturity of technologies.

Third, private investors face considerable risks during each stage of the innovation process from the research to early commercialisation. Energy technologies are more apt to fail during the development and demonstration phase than innovations in other sectors. Investors in large-scale energy innovations confront more often the 'first mover disadvantage' than the fabled advantage. Both market risks (cost, prices and product performance) as well as regulatory risks from permitting to uncertainty about policies explain these results. The regulatory uncertainties surrounding climate change policies have escalated in particular for the energy sector.

The Stern Review of 2006 and the EU's Strategic Energy Technology (SET) Plan of 2007 recognised these 'technology' market failures and argued that technology deployment cannot wait for robust global carbon prices. Thus, a major policy shift is underway, spearheaded by the EU and the USA. Public support for energy RD&D will extend well beyond the early stages of the research and innovation cycle, and address the inherent barriers to demonstration and deployment of low-carbon energy technologies discussed above with public financing support. To give two recent examples:

Earlier this year the EU Council passed a major RD&D funding stimulus totalling EUR 2.5 billion. Of this, EUR 1.050 million is slated for seven carbon capture and storage demonstration projects, EUR 910 million for smart grid and electricity connectors to help integrate renewable energy into the grid, and EUR 565 million for offshore wind projects in the North and Baltic Seas. Further, EUR 300 million allowances under the EU Emissions Trading Scheme will be worth EUR 6–9 billion depending on when they are cashed and what the price of the allowances will be on the Commodity Exchange at that time. This will drive the construction and operation of up to twelve commercial carbon capture and storage demonstration projects. The EU Parliament is expected to approve the Council's decision in early May.

These funds are in addition to the energy R&D financing of EUR 2.35 billion under the 7th Framework Programme. A Communication on 'Financing Low Carbon Technologies' will be issued shortly with proposals for further funding and new financing mechanisms.

The US American Recovery and Reinvestment Act of 2009 allocates US$32.7 billion to the US Department of Energy to spearhead clean energy RD&D and related infrastructure, along with an additional US$6.0 billion for Innovative Technologies Loan Guarantees. This includes, inter alia, US$16.8 billion for Energy Efficiency and Renewable Energy; US$4.5 billion for Smart Grid & related programs and US$3.4 billion to fund demonstration and commercialisation of carbon capture and storage. US$400 million is provided to establish ARPA-E, the new Advanced Research Projects Agency – Energy, which is modelled after the successful Pentagon research agency, DARPA.

Will this public funding stimulus for clean energy technology RD&D make a difference? Will it be matched by increased private sector RD&D and clean energy scale-up at a time of economic uncertainty and capital shortage? Will new actors enter and transform the sector? No one can foretell the eventual multiplier, but the signaling effect cannot be overlooked.

Substantial new public funding for clean energy RD&D is only part of the story. The RD&D funding is a fraction of the much larger economic stimulus packages governments have adopted to fuel employment, innovation, and growth, some with a special focus on 'green investments'. Edendorfer and Stern classify as much as 15.2 percent or nearly US$400 billion of the US$2,610 billion stimulus packages adopted by the G-20 countries as 'green' funding. China leads the Edendorfer/Stern list of green fiscal measures among the G-20, with US$201 billion followed by the USA with US$112 billion, US$31 billion in South Korea, US$23 billion by the EU, US$14 billion in Germany and US$12 billion in Japan. The mere size of the earmarked investments are staggering. The competitive landscape for clean energy will not be the same again.

Venezuelan Oil Production Data

Juan Carlos Boué

When OPEC was founded, both the press and the governments of western countries greeted the event with a resounding silence, and went out of their way to disparage OPEC as a talking club of no relevance whatsoever. Oil companies, for their part, were happy to go along with the snub, refusing to negotiate collectively with OPEC under the – strictly genuine, albeit self-serving – excuse that their respective home governments would never grant them leave to do this (by the time permission finally came, of course, their goose was well and truly cooked).

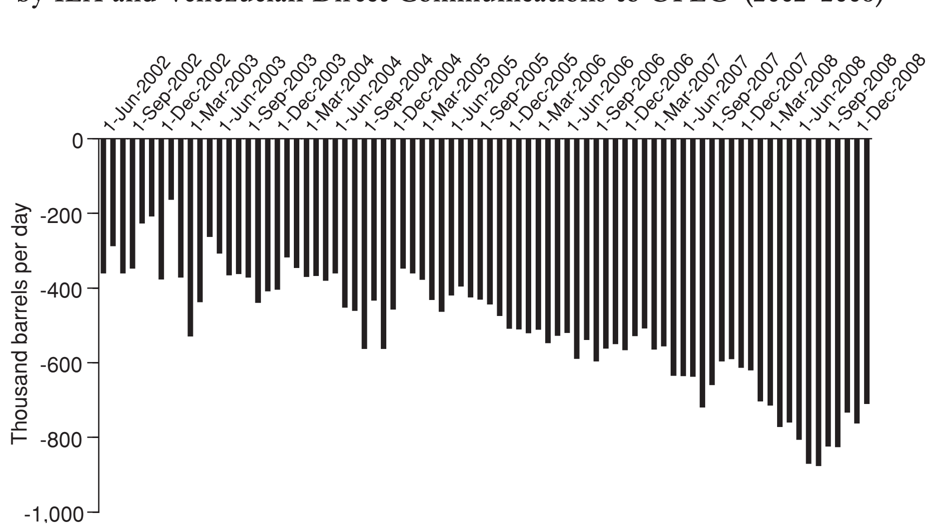
This feigned indifference on the part of companies and governments alike was an act. Indeed, as James Bamberg's magisterial corporate history of British Petroleum makes clear, plans were afoot to destroy OPEC from its very inception. The reason why these plans occupy such a prominent place in Bamberg's account, of course, is that Iran was singled out as OPEC's weakest link. Yet winds in the international oil industry at the time turned out to be so favourable that OPEC nevertheless ended up in the safe harbours of the Tripoli and Tehran agreements, which in turn laid the foundations for the price rises in the wake of the Arab Oil Embargo.

From 1990 onwards, thanks to the terminal decomposition of Venezuela's political system, this country became the weak link within OPEC. With immense enthusiasm, the top management of the national oil company, PdVSA, did their best to weaken OPEC. Their efforts in this direction were ultimately responsible for the 1998 collapse in the oil price which, in turn, paved the way for the rise to power of President Hugo Chávez. Under Chávez, of course, Venezuela has rejoined the OPEC coalition. However, much in the same way that one can still hear the echo of the Big Bang in a television set, it is possible to detect traces of the old Venezuelan-led attempt to dismantle OPEC in the difference between the crude oil output figures published by the Venezuelan government, on the one hand, and the production estimates for the country published by the International Energy Agency (IEA), as well as other secondary sources, on the other.

As can be appreciated in Figure 1, starting in 2002, there began to develop a serious difference between the two sets of figures, and nowadays this difference amounts to around 700 thousand barrels per day. Clearly, such a divergence cannot be a statistical error, which means that one of the two parties involved has to be taking some major liberties with the truth. Could the mendacious party in this controversy conceivably be the IEA? The answer to this question is by no means straightforward. To start with, all other trade journals and market watchers, to a greater or lesser extent, broadly agree with its production figures for Venezuela. Moreover, the IEA is considered to be a reputable bureaucracy. Granted, the IEA and its *modus operandi* might not necessarily be held in universally high esteem by some sections of the oil market watching fraternity, but even in those quarters, the outright fabrication of data is not the first sin that most people would be ready to lay at the IEA's door. Rather, pride of place in any account of the IEA's shortcomings would be given to its hubristic overconfidence in the infallibility of its models and assumptions, which translates into an inability (at times comical) to react quickly to developments and incorporate new information in its forecasts. A good recurrent example of this trait is the yearly spectacle of the IEA publishing an overtly bullish estimate for non-OPEC production, and then proceeding to stick to its forecasting guns come hell or high water, only to have to eat large doses of humble pie in the form of *ex post* revisions that make a nonsense of its original figures. And who can forget the unedifying episode of the missing barrels? On that occasion, the IEA's overenthusiastic estimates of worldwide oil production led it to conclude, with impeccable logic, that since vast amounts of oil necessarily had to be going into storage, and since there was no evidence of a stock build of the necessary magnitude taking place in the usual locations, therefore stocks had to be accumulating in mysterious places where the barrels were difficult to trace.

It might be thought that, due to the very inflexibility of its approach

Figure 1: Difference between Venezuelan Crude Oil Production Reported by IEA and Venezuelan Direct Communications to OPEC (2002–2008)



to modeling, the IEA's assessments would at least be reasonably free from political distortions and bias. Unfortunately, the reverse appears to be true, with the IEA somehow managing to combine methodological dogmatism, on the one hand, with ideological bias, on the other hand. And nowhere does this combination reveal itself more clearly than in the aforementioned case of Venezuelan production figures. But in order to appreciate this, it is necessary to tackle the issue piecemeal, focusing on it from a slightly wider historical perspective.

First of all, what explains the magnitude of the gap? The output of extra-heavy crude from the Orinoco Oil Belt tends to move in unison with this gap to such an uncanny degree that it is obvious that the IEA is simply not including Orinoco volumes in its assessments of Venezuelan production. Such an assertion, however, begs three further questions. Firstly, why would the IEA not want or choose to report this extra-heavy crude? Secondly, how and why would other secondary sources go along with the IEA in misrepresenting Venezuela's production figures? And thirdly, how could all of them possibly fail to spot these huge unreported volumes, and where indeed are these volumes ending up?

Let us address each one of these questions, but in reverse order. The example of the missing barrels fiasco shows that, as long as one is sufficiently blinkered, it is easy to overlook the patently obvious. Back in 1998–9, some neutral and objective observers suggested that, even if there did exist mystery locations replete with the alleged missing barrels (whose volumes, incidentally, were far in excess of the Venezuelan volumes not being reported today), these elusive barrels would nevertheless have had to be taken there somehow, and would inevitably have left tracks in chartering and shipping data. No such evidence along these lines ever materialised, of course, but that did not prevent the IEA and others from vigorously continuing to argue for the reality of these missing barrels. Quite simply, the will to ascertain that the missing barrels were an accounting discrepancy was lacking. Incidentally, this episode also suggests that stock level statistics are invested by the market at large with a degree of precision that they do not have (not least because they are residual magnitudes where error terms tend to accumulate). The inherent inaccuracy of stock data would make it quite easy for the unreported Venezuelan barrels to be lost among all the statistical noise. In this regard, it is worthwhile to point out that the spread between the highest and the lowest estimated stock build figures for 2009 in the major market tracking publications is currently running at the equivalent of a million barrels per day.

As to the agreement of the figures reported by other trade journals and industry watchers with those of the IEA, that is not at all difficult to explain. The IEA is quite rightly perceived by these other sources to be the chorus leader in this regard. In any case, all of these sources talk to one another, and none among them wants to be seen publishing figures which are at radical variance with those of the others. Also, there are some sources who recognise that they have no particular insight on Venezuelan issues, and are quite happy to go along with the conventional wisdom, for lack of better alternatives. And last but by no means least, there is the crucial fact that many of the secondary statistical sources upon which the oil market at large relies for information have maintained their political sympathies for, the PdVSA old guard.

Indeed, this last reflection brings us to the very crux of the matter: namely, that the information that the IEA and other secondary sources appear to be using in order to arrive at their production estimates is being obtained from 'tertiary sources' consisting of individuals who belonged to this PdVSA old guard, and who choose not to give these secondary sources information on Orinoco crude output, partly as a matter of political expediency, but also on grounds of ideological principle.

The political expediency dimension is easy to explain. These individuals use the data published by the IEA and other secondary sources (and, paradoxically, legitimised by OPEC itself, through its use of the production estimates of six of these secondary sources to calculate the quota baselines of its member countries) as 'proof' that the Chávez administration has been responsible for a calamitous collapse in Venezuelan oil output. Most usefully for their political action, these accusations are then, in turn, echoed by many of these secondary sources, who – in much the same way as they refused to believe that the missing barrels never existed – dismiss out of hand the idea that Chávez's populist government could have somehow managed to overcome the damage done to the Venezuelan oil industry in November 2002.

As for the ideological principles at stake, these have to do with the long-term strategy by PdVSA's former top management to make Venezuela withdraw piecemeal from OPEC. At the time that this strategy was conceived, it was obvious that Orinoco Belt volumes would, in time, account for the bulk of Venezuelan oil output. If oil from the Orinoco Oil Belt were exempted from being considered as part of the Venezuelan quota (due to its allegedly non-conventional nature), then as its production rose, a progressively smaller proportion of Venezuela's output would be covered by the country's quota. The IEA, of course, enthusiastically supported this plan: up until early 2006, it openly stated that it did not consider Venezuela's extra-heavy crude output in its 'crude target compliance calculation' for the country. At this point, the Venezuelan oil minister personally visited the IEA to inform its Director at the time that the Venezuelan government did consider these crudes as part of the country's quota, and his representations led to the IEA increasing its estimates of Venezuelan production in March 2006. Nevertheless, after only a couple of months, the figures reported by the IEA and other secondary sources had not only returned to their previous levels, but had actually resumed a downward trend (which they maintain to this day). The whole situation was now further muddled by the insistence on the part of the IEA and other sources that their figures *now included* output from the Orinoco Belt.

The IEA and other secondary sources maintain that they prepare their production estimates with due care and, above all, in good faith. In the light of the statistical anomalies that we have underlined above, such assertions ring somewhat hollow. After all, this would imply accepting that these well-meaning organisations have, for a very long time, been led astray by unscrupulous informers pursuing a hidden agenda. In any case, the secondary sources are sophisticated enough organisations for the rule of *caveat emptor* to apply in their dealings with sources of information. Finally and most tellingly, just as was the case with the missing barrels, it would be quite easy for the IEA to ascertain the true situation regarding Venezuelan output, if only the will to do so were there. After all, Venezuelan domestic consumption is a fairly well-known quantity, and the totality of Venezuelan petroleum exports has to leave the country through only seven marine terminals. Thus, to get a reasonable proxy for Venezuelan crude production, all that would be required is to tally Venezuelan seaborne exports – surely well within the reach of organisations that make much of their prowess at 'tanker tracking' – and add the resulting figure to the domestic consumption estimate.

Starting in November 2008, and acting upon the assumption that the IEA did not have the slightest interest in clearing up the uncertainty surrounding Venezuelan production figures, the Ministry of Energy and Petroleum retained an international inspection firm to quantify the monthly gross and net volumes of oil being exported from the country, on the basis of the bill of lading (or discharge certificate) issued for each and every cargo. The results of this exercise for the month of January 2009 are shown in Table 1 (the results for the other months are similar). As can be appreciated, net Venezuelan oil *exports* for this month amounted to 83.1 million barrels or 2.7 million barrels per day (this figure includes some volumes of LPG obtained from condensates and natural gas liquids). In that same month, by way of comparison, the IEA put total Venezuelan crude *production* at 2.18 million barrels per day.

The contents of Table 1 support two, mutually exclusive, conclusions. Either the Venezuelan crude oil output figures from the IEA and other secondary sources are a complete nonsense, or else the Venezuelan government is engaged in a Madoff-style and scale of deception, complete with falsified documentation and other trappings of sophisticated financial fraud. We would like to leave it to the reader to decide which one of these conclusions is the more likely, but not before pointing out that the latter alternative implies not only that cars and trucks in Venezuela are being run on a miracle fuel made from coffee rinds and banana peels, but also that Venezuela holds a very large inventory of oil somewhere, which it is drawing down month by month, with no apparent sign of the stock being exhausted (perhaps these might be the same barrels that so famously went AWOL in 1998). In passing, one should also say that if the former conclusion were true, then that would raise questions about the IEA's avowed desire to contribute to stability in the oil market by furthering transparency and data reliability, as embodied in the Joint Oil Data Initiative (JODI).

To our readers and friends

The topics covered in this issue reflect different views on important energy problems. Please join the debate by sending a letter to the editor which we will be pleased to publish

Table 1: Certified Venezuelan Oil Exports – January 2009

	Exports					Imports			
Loading Port	*Crude Oil*	*Products*	*Total Volume*	*No of Vessels*	*No of BOLs*	*Products*	*Total Volume*	*No of Vessels*	*Net Exports*
FSO Nabarima	788,658	0	788,658	1	1	0	0	0	788,658
La Salina	3,089,287	0	3,089,287	9	9	0	0	0	3,089,287
Bajo Grande	598,810	0	598,810	2	2	0	0	0	598,810
El Palito	0	2,059,556	2,059,556	7	7	478,267	478,267	2	1,581,289
Pto Miranda	4,472,120	0	4,472,120	13	14	0	0	0	4,472,120
Cardón	0	3,714,338	3,714,338	17	29	154,321	154,321	3	3,560,017
Amuay	0	10,026,500	10,026,500	31	37	451,382	451,382	4	9,575,118
Guaraguao	15,740,093	2,569,562	18,309,655	47	66	191,403	191,403	2	18,118,252
Jose	26,021,544	15,379,645	41,401,189	71	80	0	0	0	41,401,189
Total (Barrels)	50,710,512	33,749,601	84,460,113	198	245	1,275,373	1,275,373	11	83,184,740

Asinus Muses

Banana Republic

April's G-20 meeting provided the perfect opportunity to test Asinus' farmyard theory of geopolitics, described in my last instalment. The theory is holding up, but the cast list of donkeys and chickens must be augmented by tantrum-prone infants. As background, Asinus knows of one small child who refused to share a banana with his friend until an insightful adult thought to slice it length-ways, rather than cross-ways. Immediately the child was satisfied, having had an unspoken need for his banana to be banana-shaped.

This true parable illuminates the G-20 spat between France and China over a list of tax havens named and shamed by the OECD. Rather than 'endorse' the list, as desired by France but opposed by non-OECD China, or ignore it as irrelevant to the immediate crisis, a course unacceptable to France, President Obama got the parties to agree that the G-20 would 'take note' of the list. Asinus believes this to be fully the second most creative act of banana-slicing in all his diplomatic experience.

Back to Petroleum

Besides re-igniting the global economy, the world expected the G-20 to solve the problem of climate change. But convincing key players will be a struggle. BP now appears to stand for Back to Petroleum, while Jeroen van der Veer is playing the Shell game of find-the-alternative-energy-investments, having dropped all new spending on wind, solar and hydrogen energy. In a recent interview with professional grumbler and environmentalist George Monbiot, van der Veer declared that he knew precisely how much they were spending on non-hydrocarbon energy, but he wasn't telling. Why not? Because 'then those figures are mis-used, and people say it is too small.' Asinus remains unclear why saying they are too small counts as a mis-use of the figures, but perhaps that is why Asinus is not the CEO of a major corporation.

Exxon is a more difficult target of satire both because Asinus has never heard Exxon even pretend to have an interest in alternative energy, and because one feels that they wouldn't get the joke. Their unwavering petroleumism shares the blank-faced humourlessness of all fanaticisms, just as their top execs share the hurricane-proof smile of the TV evangelist.

A Horror Flick and a Fairy Tale

At least, they had better hope they are hurricane proof, if Pete Postlethwaite's new environmental movie/documentary/horror flick is to be believed. The film has Mr Postlethwaite's character looking back at our present world from 2055, asking why we did nothing while temperatures and the seas rose and civilisation collapsed. But Republican (and a few Democrat) congressmen in the USA remain unmoved, having blocked President Obama's attempt to fast-track measures to tackle climate change. Republican representative John Boehner complained that a cap and trade regime would 'raise taxes on every American who drives a car, flips on a light switch or buys a product manufactured in the United States'. Well, maybe. But is that really worse than taxing every American who has a job, and every corporation that makes a profit?

In the meantime, entrepreneur Shai Agassi is working on a scheme to sell electric cars by the mile. The business, with the hopeful name *Better Place*, is modeled on the mobile phone concept that punters pay for the service, not the object. Agassi 's partner in producing the cars is Renault, whose CEO Carlos Ghosn commented that 'Hybrids are like mermaids. When you want a fish you get a woman, when you need a woman, you get a fish.' The use of electric cars will apparently avoid this unfortunate category error; the breakthrough is to use batteries that can be replaced, not just recharged. Agassi compares ending the use of petroleum in cars with the banning of slavery in Britain, on the basis that cars cause 25 percent of global emissions today, and two hundred years ago slaves supplied 25 percent of the energy of British industry. Asinus is in two minds. It was St Augustine who wrote that 'Numbers are the universal language offered by the deity to humans as confirmation of the truth.' But it was Warren Buffet who said 'beware geeks bearing formulas'.

Banana Socialist Republic

While President Obama may have been the adult in the room at the G-20, when addressing Wall Street he and his administration seem to regress to eager-to-please puppies. In their latest wheeze to save the US banking system banks are encouraged to reveal which assets are toxic through a policy that is what economists risibly describe as 'incentive-compatible'. To the non-economist that's another phrase for 'rip-off'. Why is it compatible with banks' incentives to own up to the uselessness of their assets? Because the US administration's clever stratagem is to create a 'market' in which the 'private sector' 'buys' these assets off them. But since the government plans to underwrite 85 percent of any losses that may be suffered by whoever purchases the assets, the price that is 'revealed' by this 'market' is predicated on a giant subsidy. Such machinations are designed to avoid the evils of nationalisation – also known as tax payers getting something for their money – which, of course, would smack of the dreaded Socialism. The present scheme is an entirely different beast: targeted capital market intervention to strengthen the banking system. Or, to put it more simply, Market Socialism for the rich.

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