

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.

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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.

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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 prolific 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.

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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 MMB/D by 2014 from the current 94.5 MMB/D. It now says 7.6 MMB/D – 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.

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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.

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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. Furthermore, 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.

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

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

	<i>Revised potential</i>	<i>Actual requirements</i>	<i>Percent shelved</i>
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%

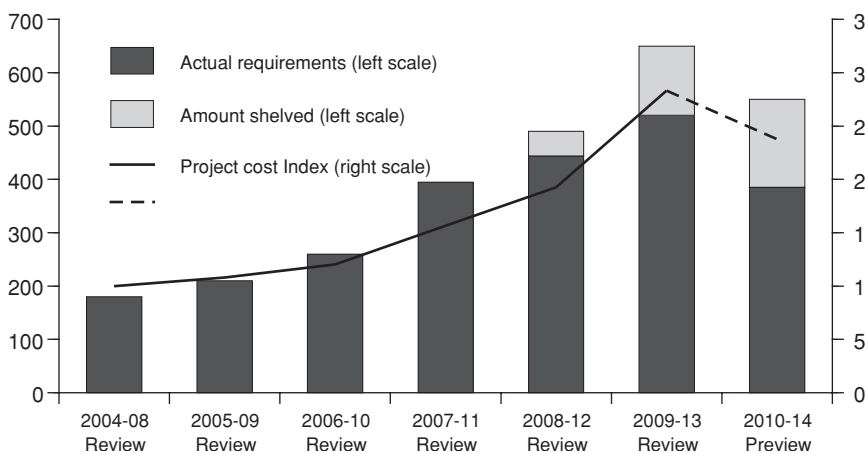
Source: APICORP Research

of project costs and the likely evolution of their main components.

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

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



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.

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.

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

