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The accident at Japan's Fukushima Daiichi nuclear complex earlier this year has reignited an old debate about the future role of nuclear power in the global energy mix. The repercussions of the Fukushima accident are likely to be felt for quite some time with some observers claiming that the accident has put an end to the 'nuclear renaissance'. Malcolm Keay is of this view arguing that 'although Fukushima may not have the traumatic impact of Three Mile Island or Chernobyl, it is likely to be another turning point on the winding road of nuclear development – renaissance postponed, at least for the foreseeable future.' But not everyone agrees.

Malcolm Grimston calls for some caution arguing that 'striking as the similarities may seem, there are key differences between the situation post-TMI and Chernobyl and the position post-Fukushima which suggest that the response may not be as damaging for nuclear construction. He concludes his article with an optimistic note arguing 'that the prospect for good science-based policy to get us out of the two-pronged resource and climate crisis may be brighter than perhaps seemed to be the case before Fukushima'. He cautions against the debate being hijacked 'by the theological and inflexible extremes from either side of the nuclear debate'.

According to Gordon MacKerron, 'the basic message emerging from all three accidents is that from either internal (TMI and Chernobyl) or external (Fukushima) initiating events, the value of a highly capital-intensive investment can be written off in a matter of hours'. Fukushima therefore reveals clearly the 'financial and economic risk of a nuclear investment, and one which hardly applies at all to alternative electricity generating options'. Gordon MacKerron points to a clear divide in prospects of nuclear power, with new nuclear power failing to increase its share in countries in which states would not guarantee a minimum level of return. In contrast, countries in which 'nuclear is regarded as a strategic investment then the delay and discouragement caused by Fukushima may be much more limited'.

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On 20 April 2011, the Gulf Cooperation Council (GCC) moved one step further in its efforts towards greater regional cooperation by inaugurating the UAE's link to the GCC Interconnection Grid which interlinks five of the six GCC countries' national electricity networks. In this Forum, Laura El-Katiri evaluates the potential economic and political impacts of the GCC Interconnection Grid for the region. She notes that although currently 'the regional power grid serves only as a back-up mechanism supplying electricity-deficient countries with ad hoc electricity supplies', it has the potential to evolve as a commercial tool for electricity trade. The challenges for establishing a regional electricity market are immense, but the author concludes that the GCC grid represents 'a tangible achievement…. with enormous economic potential for the long-term development of the region as a whole'.

In the last few years, there has been much optimism about Brazil's oil prospects with some media reports referring to Brazil as the next oil giant. As Juan Carlos Boué notes in his article: 'global oil consumers are counting on the aggressive development of Brazilian oil and gas resources to take at least some of the edge off the very high prices.' Notwithstanding the substantial progress made so far in developing Brazil's oil reserves, the author calls for some caution 'not least because outright conflicts involving governments, on the one hand, and their national oil companies, on the other, have culminated in especially messy outcomes'.

James Henderson looks at another important source of non-OPEC supply: Russia and its Eastern oil resources. The author explores the potential for oil output in Russia's eastern regions which could produce over 2 million barrels per day of oil by 2020 and 2.5 million barrels beyond that. However, he admits that 'it would be wrong not to acknowledge some important risks to the development of that potential'. These challenges however can be addressed by the introduction of a tax system that incentivises investment and risk-taking.

In the final article, Bassam Fattouh explores the evolution of the gas sector in Saudi Arabia. The author argues that while the Kingdom has been successful in developing its gas market and increasing its contribution in the domestic economy, the current gas strategy, based on providing cheap gas to final consumers and achieving self-sufficiency in gas with no plans to export or import gas, is facing some serious challenges. Government policies pursued to deal with these challenges, including doing nothing, will have wide implications not only for the long-term sustainability of Saudi Arabia's industrialisation and development path, but also for global energy markets.

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Nuclear Energy post Fukushima

Malcolm Grimston considers the hidden lessons

Surely we have been here before? In 1979 the world was in a recession caused by high oil prices; nuclear investment, though costs had stabilised since the early 1970s, was looking more expensive than had been expected a decade earlier; a sophisticated anti-nuclear movement had developed, and had for example been instrumental in ensuring that the Zwentendorf plant in Austria was refused an operating licence although it had been completed. Then came the accident at Three Mile Island in Pennsylvania, followed in 1986 by Chernobyl (Ukraine). Costs of nuclear investment shot through the roof as plants had to be redesigned (in many cases after construction had already begun), public and political sentiment changed decisively, leading to an Italian referendum to shut down their nuclear plants immediately (or at least by 1990), a phase-out policy in Germany, a whole range of other countries such as Switzerland placing moratoria on new build or barriers to entering the nuclear club. Liberalisation of power markets created further challenges for heavily capital-intensive sources of power like nuclear.

So why should it be different this time? Well, it might not be, of course. But there are key differences, both in the external environment and in the realms of nuclear technology and public perceptions.

Key Differences in the Environments of 1979 and 2011

Striking as the similarities may seem, there are key differences between the situation post-TMI and Chernobyl and the position post-Fukushima which suggest that the response may not be as damaging for nuclear construction.

First, TMI and Chernobyl happened at times of over overcapacity in electricity supply systems of many countries, caused by over-ordering in the early 1970s and the subsequent effect of the global recession. By contrast, the early years of this decade are a time of impending capacity shortages, not least in the UK, as the first cycle of liberalisation (which largely involves sweating existing assets rather than new investment) comes to an end. In developing countries, notably in the Asia-Pacific region, electricity demand is burgeoning (Figure 1).

So there is a need to invest in large amounts of new generating capacity of some description. The more of the new plant that is fossil fuel-fired, the more the world is locked into greenhouse gas emissions for some decades, depending on the lifetime of the plant in question. For baseload power, given the current state of technology, the intermittency of many renewables is a significant barrier, while carbon capture and storage has not been demonstrated on a very large scale (the first UK pilot, at Longannet, unlikely to be operational before 2015). In effect then, the choice for new baseload capacity is nuclear, coal or gas. The geopolitics of gas, for example the interruption of Russian supplies to Ukraine in 2005, and the carbon emissions associated with LNG look more challenging than they did in the 1990s, though the prospects for shale gas may change these perceptions considerably.

Secondly, TMI occurred at a time when many plants were already under construction. Backfitting design changes is a more expensive business in such circumstances, because of both inherently higher costs and the effects of keeping committed capital tied up without an income stream for several years (or indeed for ever in the case of Shoreham in New York State, which was never granted an operating licence as an acceptable evacuation plan could not be agreed with local regulators). If a major nuclear renaissance is under way today it is still in its infancy, with only 65 plants under construction globally at the end of 2010; any necessary post-Fukushima redesign should be relatively cheap.

Third, of course, is the growing influence of climate change on the debate, if not as yet on policy in any serious way. Despite decades of calls for greater energy efficiency and more renewables, the goal record on carbon dioxide emissions since the Kyoto base year of 1990 has been woeful, 2010 seeing the greatest increase on record.

Learning from Mistakes

There are important differences concerning the technology as well.

Most notably, both Three Mile Island and Chernobyl occurred because of

Figure 1: China Electricity Demand (TWh)

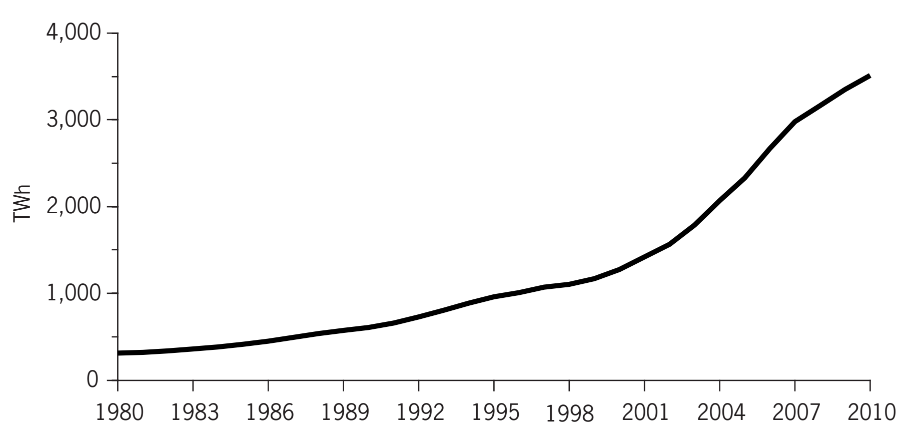
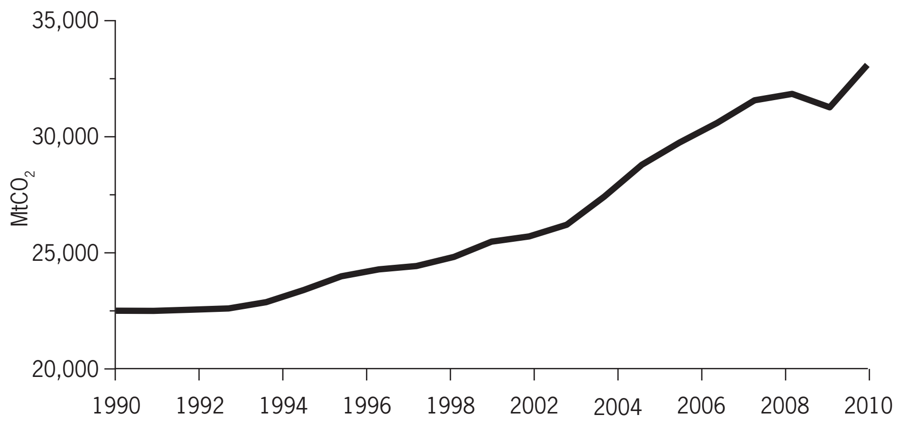


Figure 2: Global Carbon Dioxide Emissions from Oil, Coal and Gas, $MtCO_2$



problems with the plant, not because of outside challenges. Both occurred in reactors that were only a year or two old. In the case of TMI, it was a Pressurised Water Reactor, the dominant nuclear technology then and indeed now. As a result, TMI in particular was enormously relevant to the nuclear plants under construction or planned at the time. (Chernobyl was a design – RBMK – unique to the former Soviet Union which had been rejected in a several countries, including the UK, owing to safety concerns around the possibility that it could 'runaway with itself', which is what happened in 1986.) Fukushima, by contrast happened in technology that had been developed in the 1960s at the very start of the large-scale deployment of nuclear power (the first ever commercial-scale reactor only opened in 1956, at Calder Hall in the UK). One of the most remarkable features of the accident in Japan was how all 14 reactors in the earthquake/tsunami zone withstood the earthquake and the 10 newest ones (plus Fukushima unit 4, which has been defuelled) were in cold shutdown within a week of the tsunami.

Nonetheless, one result of the lessons learned from Three Mile Island involved a reappraisal of the level of dependence on engineered safety systems. The 'multiple redundancy' principle, whereby several back-up systems are provided to ensure availability of a safety function, has been generally very effective in ensuring plant safety in a range of anomalous operating conditions. But, the plant can still be severely compromised under certain conditions. First, albeit highly unlikely, is the independent and coincidental failure of all back-up systems. Secondly, much more difficult to assess, is the possibility that the safety systems might interact with each other in an unpredictable way. Third, as was seen at Fukushima, a severe external stress which caused simultaneous failure of all back-up systems, in that case generators to keep the cooling water pumps operating and remove waste heat from the reactor cores after they had tripped, could leave the plant in severe trouble.

Probabilistic Risk Assessment, leading to statements like 'major core degradation every 10 million reactor years', has proved reasonably accurate in other industries with regard to the first of these three risks. But there have been five major core degradations (TMI, Chernobyl and Fukushima Daiichi units 1–3) in 12,000 reactor years, suggesting that the calculations are seriously deficient when it comes to the real world.

The response was to develop passive approaches to safety in an emergency situation. The Westinghouse AP1000, for example, has a large reservoir of water situated at the top of the primary containment, connected to the containment by pipework and pressure valves. Should all power be lost to cooling circuits, pressure will build up in the containment, causing the valves to blow and water to fall under gravity into the containment. No power is required, giving an estimated 72 hours to get emergency water or power to the core. Fukushima may give a further push towards such 'Generation III+' approaches to safety, notably in China, the only major market where plants of Generation II technology (albeit a very modern version, the CPR, with many advanced safety features) are being built

The Response to a Major Accident

The immediate and longer-term local response to a nuclear accident is perhaps a field in which the lessons from TMI and Chernobyl have not been learned so effectively.

There was practically no release of radioactivity at Three Mile Island. At Chernobyl there was a huge release, coupled with mistakes made by the authorities which led to a fatal delay in distributing iodine tablets to the most affected populations. As a result there were some 6000 cases of thyroid cancer (and perhaps 15 fatalities). Apart from this, the credible (peer-reviewed) literature suggests that it is extremely difficult to find radiological health detriments among anyone not on site during the accident or in the clean-up operation, though there is widespread stress-related illness. (Similarly, the *Report of the President's Commission on the Accident at Three Mile Island* stated, 'We conclude that the most serious health effect of the accident was severe mental stress, which was short lived.') However, the health records of residents in the Chernobyl area before the accident were poor to non-existent, inevitably reducing confidence in the findings. On average, lifetimes of those in the regions affected by fallout may be reduced by a few minutes but this will not be detectable against natural variations in mortality. But even if some of the apparently more fanciful claims are closer to the truth, the health effects pale compared to those of other forms of environmental pollution, let alone climate change.

Fukushima will give much better data and hence allow more comprehensive analysis. It may also offer an opportunity to put the risks into perspective.

Though it is too early to be sure, it is likely that the risk of living in a city like Tokyo, with its air pollution, is higher than that of living in at least the southern reaches of the evacuation zone. (The World Health Organisation estimates some 2.5 million early deaths per year because of airborne pollution in cities.) If so, it would ironically be a stronger argument purely on health grounds to move the citizens of Tokyo into the evacuation zone than vice versa.

> "In effect then, the choice for new baseload capacity is nuclear, coal or gas"

This leads to some interesting speculation about the financial costs of the accident. Does it make sense to introduce evacuation measures with very heavy financial costs and no net health benefits, and if so to whom should those costs accrue? As Richard Wilson points out in the *Bulletin of Atomic Scientists*, 6 July 2011 (generally regarded as sceptical in nuclear matters), before 1980 the US Nuclear Regulatory Commission asked for an 'Emergency Planning Zone' with a 10-mile diameter around each nuclear power plant, but after the Three Mile Island accident these areas became 'evacuation zones' without much discussion. There should be an important distinction drawn between compulsory evacuation and voluntary evacuation. Faced with a nuclear accident, some people will want to leave voluntarily, and government can play a valuable facilitating role for example in creating one-way streets and banning parking on exit routes. But compulsory evacuation is much more difficult to justify, as is ongoing prevention of people from returning to their homes if they so choose to do. 'The high-speed train from Tokyo to northern Japan was discontinued for three months to avoid exposing passengers to minuscule doses of radiation. Those who travelled by air instead got a similar dose from the increased cosmic radiation at higher altitudes!'

Wilson goes on to argue that the proposed contamination levels above which citizens would be prevented indefinitely from returning to the area, at 10–20 mSv per year, would be irrationally low and entirely counterproductive, citing World Health Organisation figures reporting a 5 percent increase in cancer rates for anyone dislocated for any reason. '[The whole furore] contrasts with more than 15,000 dead bodies and nearly 8,000 people still missing after the earthquake and tsunami.'

The Changing Debate

Another striking feature of the Fukushima accident has been the wide range of public and political responses in different countries. A major Gallup poll held when the accident was at its height (involving 34,000 respondents from late March to April 11) showed a majority of those polled still supported nuclear new build, although the net positive figure had fallen from +27 percentage points to +6. However, even leaving out Japan itself, there was a huge difference between the major antinuclear swing in countries like Germany and Italy and the relatively phlegmatic response in South Korea, China (which remained heavily pro-nuclear) and the USA. In the UK a *Times* poll in early July showed support for replacement build falling from 52 to 47 percent in the UK (opposition growing from 24 to 28 percent), representing support at similar levels to what it had been in 2007. The calm and measured response from the UK coalition government contrasted with the sheer political panic displayed for example in Germany. That an event of this nature should have so little effect on public perceptions suggests that the British public, at least, has quite a sophisticated, considered and even settled view on nuclear power, though of course the longer-term trends will need to be monitored to check this hypothesis.

The media coverage in the UK was interesting. In the past the opportunity would perhaps have been grasped to seek out the most extreme views (pro or anti nuclear power), no matter how little credibility they might command among serious scientific commentators, in order to maximise the theatre and the controversy. This time the 'pantomime dames' from either side of the debate hardly made an appearance. A range of mainstream views (including those of credible nuclear sceptics and supporters of course, plus the growing ranks of committed environmentalists who now support nuclear power) was sought and the coverage was responsible and sober. In particular, those whose extreme views have added shamefully to fears of radiation and thence to stress and mental health problems seem to have been found out and bypassed.

Three phases can be identified in the historical relationship between the nuclear industry (insofar as the term makes any sense in these days of large companies with cross-national and cross-technology portfolios) and the public. During the first wave of nuclear investment, industry in general, and nuclear proponents in particular, were largely trusted and respected by public and politicians alike (just as people broadly trusted their governments). The nuclear industry was given pretty much free rein, including enormous state investment and a large say in setting public policy as well as executing it. The industry became rather arrogant, secretive and perhaps even deliberately dishonest, although in the author's experience (from the late 1980s onward) there were many people of the highest personal integrity at the top of the industry.

Then people started to notice that industrialists, and scientists working for them, sometimes told untruths, more often were wrong, more often still were secretive and most of all were prone to exaggeration and wishful thinking. A growing Green movement in particular captured a growing sense of public disillusionment, and public sentiment moved close to rejecting the very idea that science and technology have a unique contribution to make to human wellbeing. It took (the) industry quite a time to realise this was happening.

The beleaguered nuclear industry has slowly and imperfectly begun to mend its ways and become more open, honest and humble, though its previous attitude has understandably made this difficult for some people to believe (and in some countries, notably Japan, it is not clear whether the process has really started at all). At the same time the Greens, as free from serious challenge as the nuclear industry had been in its early days, similarly started to treat people of opposing views with contempt and sometimes personal abuse and to believe in their own supposed (and fictional) moral superiority and infallibility. Bit by bit people started to realise that Greens too are sometimes untruthful, more often wrong, frequently secretive and have a pronounced tendency to wishful thinking and exaggeration. Greens talking passionately about the need for renewables while pocketing large subsidies for manufacturing solar panels can no longer expect an easy ride.

The public (and the media) may now be moving into a healthy Marxist synthesis of challenge and scepticism towards industry and Greens alike. Science and technology are increasingly recognised as having a unique contribution to make to decision-making and public happiness, but not to be trusted to set their own technocratic agenda to the exclusion of democratic and ethical values. There is no longer a need for the untrustworthy wing of the Greens, but every need for robust and credible challenge to all viewpoints, something which the broadcast media seem to have sensed and to be acting upon.

If so, the prospect for good science-based policy to get us out of the two-pronged resource and climate crisis may be brighter than perhaps seemed to be the case before Fukushima. Whether that is enough to get us through is a different question, but to be able to have the debate unhampered by the theological and inflexible extremes from either side of the nuclear debate must be a good start.

Gordon MacKerron assesses the economics of nuclear power after Fukushima

It may be several years before the full ramifications of the Fukushima accident are understood. But some early effects around the world are starting to become visible and this article concentrates on the implications, visible and prospective, for the costs and overall economics of nuclear power.

Much is already being written about the potential effects of Fukushima relative to those experienced after Three Mile Island and Chernobyl, and whether or not these will be greater or less than the consequences of these earlier accidents. However it is the similarities rather than the differences that seem to matter most. All three did (or will) lead to a substantial pause in the international nuclear enterprise. More to the point in the context of the economic status of nuclear power, the basic message emerging from all three accidents is that from either internal (TMI and Chernobyl) or external (Fukushima) initiating events, the value of a highly capital-intensive investment can be written off in a matter of hours. But bad as this is, more follows. The clean-up bill after these accidents is also much larger than if standard decommissioning and waste management were involved. Fukushima therefore points up a large (but not the sole) financial and economic risk of a nuclear investment, and one which hardly applies at all to alternative electricity generating options.

Besides the re-iteration of this underlying financial risk of nuclear investment, the Fukushima accident is leading to reviews across the nuclear-using world of the design of potential new reactors – primarily, their robustness to major external threats to their integrity, and the capacity of multiple and redundant systems to respond quickly and effectively to major malfunctions. The implications of any given level of added costs that will result from these review processes depend on the extent of the competitiveness of nuclear power before the accident took place. So how was nuclear power doing relative to its competitors, mainly gas-fired and coal-fired power?

The answer is not clear. The nuclear 'renaissance' has not yet really got under way – in the OECD area, no reactor has yet been completed and only two have started construction – and so there is no experience of real costs. When the idea of the nuclear renaissance took hold around 2005, the nuclear industry suggested that some low costs were feasible. In the USA, target figures of $1000/kW were taken seriously, a level well below the figures achieved historically. The confidence behind these low numbers derived mainly from the expectation that a new generation of reactors would in principle be much cheaper than the previous generation, driven by substantially reduced material inputs (the Westinghouse AP1000) or expanded economies of scale (the Areva 1650 MW EPR). Even before Fukushima however, it was clear the costs would be much higher than $1000/kW. Rising costs were driven by rising raw material costs and a more realistic appreciation of what a design that was able to get regulatory approval would look like.

Nuclear construction costs have had a difficult history and the 'appraisal optimism' that has characterised many new technologies has been especially acute for nuclear power. While other new technologies have benefited from reduced costs as learning and economies of large numbers have reduced costs, in the case of nuclear, technical advances have been frustrated by increasingly stringent regulation, adding substantially to the cost. Even before Fukushima, prospective costs had already started to escalate substantially. The first new OECD-based reactor, the EPR being built by Areva at Olkiluoto in Finland was already running over three years late. It also had a revised cost estimate well over 50 percent above original 'turnkey' level, and was estimated to have reached 5.5 bn. euros. As the first of a kind, it was not surprising that the project was running well over budget especially as there were significant regulatory issues that had not been ironed out in advance of construction start. It is not yet clear what further escalations may now be the result of reviewing Fukushima.

> "in the next few years, gas-fired power will almost everywhere be cheaper than nuclear"

The second EPR, being built by EdF at Flamanville was already showing some signs of over-running (its cost estimate had escalated from 3.3 bn. to 4 bn. euros in advance of Fukushima). But in July, the first indications of the impact of cost reviews following Fukushima were announced, and they referred to Flamanville. The expected cost has now increased to 6 bn. euros and the time over-run will now be at least three years. It is worth looking at this number compared to earlier US expectations of $1000/kW. The Flamanville project is now running at c. $8.6 bn. or some $5200/kw, five times more than some early US hopes. It is also worth comparing this estimate with those made for the UK, especially as the analogy between French and UK costs might also be expected to be better than between France and the USA, as EdF will be the first vendor of a new reactor in the UK. In 2008, the UK government suggested that the cost for a new reactor might be of the order of £1250/kW, or $2000/kW. But translating the new Flamanville estimate into UK terms yields a cost of almost £3200/kW, over 150 percent higher than the UK government's 2008 expectation.

What do these large escalations mean for the competitiveness of nuclear plant? Taking the UK example, the government's 2008 expectation was that at £1250/kW nuclear would be cheaper than alternatives as long as the EU ETS price for carbon dioxide was at 36 euros/tonne. At £3200/kW competitiveness would require the price of carbon to be at a level well over 100 euros/tonne, something no one seriously imagines will eventuate. At these kinds of cost level, and bearing in mind that shale gas in the USA means that gas prices are unlikely to escalate in the next few years, gas-fired power will almost everywhere be cheaper than nuclear. Further, the cheaper renewables are also likely to do well in a direct cost comparison.

But things are somewhat worse than this. The numbers quoted above are engineering-based, taking no explicit account of project risk. The write-off risk mentioned above may be seen by investors as very small for new technology where there is less risk of earthquake/tsunami conditions, and following the new cost-increasing measures that will now be put in place to help robustness. But the overall financial risks of a nuclear project remain significantly higher than for alternative power projects – regulatory and political risk are especially important, quite separately from the effects of Fukushima. This means that where nuclear investment is expected from private sources, and subsidies and/or carbon prices are low, the attractiveness of new nuclear investment will now be very low.

This suggests that prospects for new nuclear build are now poor throughout all of the OECD, where private investment is now the norm and states are unwilling or unable to guarantee minimum levels of return. The picture may however be different for the non-OECD world, where activity in new-build was already stronger, especially in China and other parts of South and East Asia. Where governments either supply the bulk of the finance or are willing to guarantee the returns available to nuclear investment by allowing consumers to pay for whatever costs are incurred, the relatively higher risks of nuclear investment are either absorbed by the state or passed on to consumers. In these situations and in countries where nuclear is regarded as a strategic investment, then the delay and discouragement caused by Fukushima may be much more limited. As the article by Malcolm Keay also suggests, the expansion in nuclear power in the next decade or so may be mainly confined to developing Asia. And as China, with easily the world's largest nuclear programme, is now beginning to internalise the technology being transferred to it by both Westinghouse and Areva, this is the place, in ten years' time, that will be the world's main source of commercial reactor technology.

Malcolm Keay looks at policy responses in the USA, Asia and Europe

Harold Macmillan is famously said to have remarked that the biggest problems for any politician were 'events, dear boy, events'. It is an indication of the highly political nature of nuclear power that it has been events, as much as economic and technological fundamentals, which have affected its development over the past four decades. At first, this worked in favour of nuclear. The oil crises of the 1970s led to a massive expansion in nuclear programmes worldwide. But the US programme starting slowing down in the late 1970s and the core meltdown at Three Mile Island in 1979 proved fatal; over 50 reactors on order were cancelled over the next five years and no new orders have been constructed since then. In Europe, the expansion was sustained a little longer, but Sweden held a referendum in 1980 which led to a decision to phase out nuclear power; Spain decided on a moratorium in 1983. Some countries held out until the Chernobyl explosion in 1986 proved another turning point; Italy announced a closure programme following a referendum in 1987. In other countries, like the UK, the slowdown in demand and a surplus of capacity meant that the issue could be put on the back burner in the hope that the impact of the disaster would be forgotten. Only a small number of countries with particular concerns about energy security – France, Finland and some parts of Eastern Europe – retained active programmes.

During the early 2000s, as memories of Chernobyl faded and concerns about climate change increased, nuclear crept slowly back on to the agenda. With the energy price rises of the second half of the decade nuclear seemed to be in favour again and there was confident talk of a 'renaissance' – though few orders, at least in the OECD. Has the Fukushima incident put an early end to this renaissance? The article in this *Forum* by Malcolm Grimston presents a relatively optimistic view of the implications for nuclear construction; Gordon MacKerron looks at the economics and paints a more pessimistic picture. This article looks at the policy impacts and in particular at the policy changes announced. In the OECD at any rate the implications are likely to be serious – directly for nuclear power, and in their effects on energy security and emissions. The effects outside the OECD are likely to be less severe, reinforcing a trend already under way during the first decade of this century – whereas during the twentieth century, nuclear plant construction was concentrated in OECD countries (particularly in the USA, Europe and East Asia) and in the former Soviet bloc, during this century the main focus of attention is likely to be the Middle East, South Asia, China and Russia.

The policy response to the Fukushima incident can be divided into a number of main regions. First, in North America, the response has been relatively muted, but this is because nuclear was in any event falling from favour. During the last decade, prompted primarily by concerns about energy security, the Bush administration gave strong policy support for new nuclear construction under the Energy Policy Act 2005 and a wave of new plants seemed to be on the horizon. However, interest has now declined – the arguments for nuclear are less pressing in the USA than elsewhere. For instance, growth in electricity demand is much slower than in Asia; US climate change objectives are less ambitious than in Europe. Furthermore, the development of large deposits of shale gas has created the prospect of low gas prices for the foreseeable future and has avoided any need for significant imports (as had seemed to be the case a few years ago). Add to that a President who is at best lukewarm about nuclear, and a political impasse which makes any major developments on climate change and energy policy unlikely, and the nuclear issue can be expected to stay on the back burner for some time. While it is not possible to rule out some nuclear new build in the USA, even the nuclear industry itself does not expect to see more than four new units by 2020 (as compared with the 104 in operation today). Given that most existing capacity is thirty or forty years old, the expected retirals would lead to a decline in total nuclear capacity. But the implications of US inactivity for the rest of the world are comparatively minor. The US can achieve a significant degree of decarbonisation simply by shifting from coal to gas so the decline in nuclear is unlikely to push up carbon emissions; and the abundance of shale gas means that the increased gas use is unlikely to have much impact on world prices.

With Japan the global implications are more significant but the position is less clear. Japan has relied significantly on nuclear power, for security and environmental reasons, but in the light of the Fukushima incident is undertaking a rethink. This could mean withdrawal from nuclear – Prime Minister Kan reconfirmed in mid-July that Japan should aim for a society that does not depend on nuclear power and pledged to increase the emphasis on conservation and renewables. However, some of his Cabinet colleagues disagree and there is as yet no overall roadmap for a transition (which Mr Kan has said must happen 'systematically and in stages'). The problem is that the many constraints which originally pushed Japan towards nuclear power are still there and it will not be easy to find alternatives to nuclear. This is an immediate as well as a longer-term problem; Japan used to depend on nuclear for around 30 percent of its electricity but the programme was largely the brainchild of the central government. Local communities were often less happy with having a nuclear plant in the vicinity – for obvious reasons, nuclear power has had adverse connotations for many Japanese. Following the Fukushima accident many reactors were closed for inspection or routine maintenance; they are only being reopened after they pass a series of tests and the decision is generally in the hands of local officials. At the time of writing only 19 out of 54 reactors were in operation and power supply remains tight. South Korea is facing a similar period of soul-searching. It has a major commitment to nuclear power with five reactors under construction but is, unsurprisingly, having to rethink its approach. As with Japan, the constraints are powerful and the alternative strategies difficult to elaborate.

> "It is in Europe that the policy response has to date been clearest"

The likely short- and medium-term impact is to put more pressure on traded gas supplies. In both countries any new energy strategy remains to be settled and conservation and renewables are in any event longer-term options, so this is likely to affect markets for some time – indeed it could be the case for most of the rest of this decade, after which markets were in any event expected to tighten again. Gas markets in the Pacific therefore seem destined to remain tighter than expected for some years to come.

It is in Europe that the policy response has to date been clearest:

- Germany has decided to phase out its nuclear plants (which currently supply about one quarter of its electricity) by 2022, and not to reopen the eight old reactors that are currently off-line. This will have big implications for its environmental and energy policies. Despite its commitment to renewables, and especially wind, Germany is probably going to have to build about 20GW of coal and gas plant to replace its nuclear fleet. The coal market may not be greatly affected, given the decline in coal use elsewhere in Europe (and the dominance of the Pacific in world coal markets). However, there will be a lasting impact on gas prices, as in the Pacific, and the previous confident expectation of a well-supplied European market now looks less certain. In addition, while the new fossil plant is described as only transitional, it will still make the achievement of Germany's ambitious environmental targets difficult or impossible – Germany is aiming to reduce emissions by 40 percent by 2020 and 80 percent by 2050. While it is helped by the fact that the baseline year of 1990 includes the Eastern länder, where emissions declined rapidly after reunification, this will still be difficult or impossible. At the moment (and before the nuclear closures) Germany was only on track to achieve reductions of around 30 percent. The nuclear closures will add around 30 million tonnes of carbon dioxide emissions a year until new measures can be effected (or nearly 5 percent of emissions) leaving a huge gap against the target. It will probably also lead to significant levels of electricity imports into Germany, potentially putting pressure on other countries' emissions (or leading Germany to import nuclear while denying itself its own indigenous sources).

- In Switzerland the plan is to phase out nuclear power by 2034. The wider implications for fossil energy prices and the environment are probably not significant given the long time scale but for Switzerland the energy policy impacts will be major. Switzerland gets around 40 percent of its power from nuclear and will find it difficult for environmental reasons to expand its other main source, hydro, so it will have to rely on renewables such as solar and conservation efforts, both of which might prove difficult.
- Developments in other European countries are likely to have less of an impact. Italy has voted in a referendum against restarting its nuclear programme (against the government's wishes) but that merely confirms the status quo. Spain remains lukewarm in general and opposed to new plant construction. In Sweden, which seemed to have been reconciling itself to a resurgence in nuclear power, opinion has now swung against the option again. The UK has not formally changed its position but, with the government's proposals for Electricity Market Reform starting a slow process of implementation, new construction is not likely soon and there has been speculation about whether RWE and EOn remain committed to nuclear development in the UK, given developments in Germany. France, of course, retains its commitment to nuclear as do a number of smaller countries, such as the Netherlands and Finland, along with much of central and eastern Europe. However, given the impact of the recession, the slowdown in electricity demand and EU energy efficiency programmes, only a small number of new plants are likely to come on stream in the next decade or so. As in the USA, there will probably be a net decline in nuclear capacity in Europe.

Even in non-OECD countries there have been some protests and a slowdown in some areas – China suspended approvals for new plants while it reviewed their safety. However, in general active interest in nuclear remains high in the regions mentioned above. As Malcolm Grimston's article points out, the underlying need for nuclear power has not been affected by Fukushima; many non-OECD countries see the primary role of the energy system as to support economic development and that remains the central priority of their governments.

Overall the current position is that around 60 reactors are under construction worldwide; China, Russia and India alone account for about two-thirds of the total and all have strong reasons for continuing their programmes – energy security concerns in the case of the Asian superpowers and releasing gas for export in the case of Russia. However, the 60 under construction compares with around 440 currently in operation; it is also estimated that around 30 plants worldwide will be closed as a result of Fukushima and, as noted, many countries in the OECD are now scaling back or reconsidering their plans for the future. Even if the impact outside the OECD is less marked, so that we are not likely to see the widespread freeze on new plant which marked previous incidents, three broad conclusions seem to emerge:

- Climate change concerns are not themselves going to lead to a resurgence in nuclear; the countries with the greatest commitment to emissions reduction are also those most worried about nuclear safety issues.
- The centre of gravity of nuclear development will move from the OECD, to Asia and the Middle East in particular. This could well further discourage development in the OECD. Any nuclear investor is taking on the risk of an accident anywhere in the world as Gordon MacKerron's article underlines. While there is no specific reason to believe that safety standards will be lower outside the OECD, the scale of construction there will increase that risk, if only because, in many cases, transparency outside the OECD is lower.
- The implications of the nuclear slowdown are tighter gas markets in the Atlantic and Pacific; higher carbon emissions and, as a consequence, higher energy prices generally, especially in Europe.

In short, although Fukushima may not have the traumatic impact of Three Mile Island or Chernobyl, it is likely to be another turning point on the winding road of nuclear development – renaissance postponed, at least for the foreseeable future.

Interconnecting the GCC States

By Laura El-Katiri

On 20 April 2011, the Gulf Cooperation Council (GCC) celebrated the inauguration of the UAE's link to the GCC Interconnection Grid, an extensive 1200MW high-voltage system interlinking five of the six GCC countries' national electricity networks. Originally conceived in the early 1980s, the project's implementation and financing remained uncertain for two decades, until high windfall oil and gas revenues from the early 2000s and exploding power consumption rates finally prompted the GCC heads of state to officially proceed with the grid in 2004 and tender out construction contracts. Following the grid's initial inauguration in July 2009, when Bahrain, Kuwait, Qatar and Saudi Arabia first 'plugged in' to one another, the recent link of the UAE to the grid constitutes another milestone in the project's epic history. The only link left for completion is the one between the UAE and Oman, which is planned for 2013.

This article explores the economic and political significance of the GCC Interconnection Grid for the region. Currently, the regional power grid serves only as a back-up mechanism supplying electricity-deficient countries with ad hoc electricity supplies. In the long term, however, the grid has the potential to effectively become a tool for commercial electricity trade between the GCC states and hence to help create a regional electricity market, also leading to far greater economic integration; that is, if GCC policy-makers continue to support regional institution building in the utilities sector, while also engaging in necessary domestic market reforms.

Economic Benefits (and Limitations) of the Grid in 2011

The GCC grid today functions as a cross-regional security mechanism that allows the transfer and exchange of electricity between the interlinked countries' national power systems at times of emergency, i.e. when domestic reserve or generation capacity is insufficient to supply peak demand. The primary idea behind the GCC grid's emergency mechanism makes use of cross-regional differences in electrical load structures: where one country suffers a power shortage, another country's 'idle' capacity can help support a neighbour's system stability, by providing extra reserve or generation power. The mechanism benefits both parties since the receiving party pays back the electricity in kind, thus supporting another neighbour at times of emergency.

This regional security mechanism is badly needed: fast rates of energy demand growth, including in the electricity sector, have led to high consumption growth rates for electricity in several GCC states since the 1970s. Total regional consumption of electricity between 1980 and 2009 rose nearly tenfold and is forecast to continue to grow at high rates along with the expected high economic growth in a region with average GDP growth figures of between 5 and 9 percent in the past decade. Per capita consumption rates are already among the highest in the world in parts of the GCC, with Qatar and the UAE leading global per capita demand tables for electricity (see Table 1). Economic diversification programmes since the 1970s aimed at raising non-oil output have driven much of this consumption growth. In addition, electricity in the GCC has been subsidised by the state for nearly four decades, leading to a zero or near-zero cost of energy used by citizens and their companies, with the result of a lack of incentive to save energy or to invest in greater energy efficiency.

Table 1: Comparative Economic Indicators for the GCC

	GDP per capita, PPP (constant 2005 international dollars), 2008	*Population thousands 2008*	*Electricity Production (TWh) 2008*	*Electricity Consumption (TWh) 2008*	*Electricity Consumption p.c. (KWh) 2008*
Bahrain	32,233	1,106	11.2	10.5	10,390
Kuwait	45,539*	2,496	48.6	42.6	13,373
Oman	23,333	2,867	15.3	13.3	4,619
Qatar	84,043	1,448	20.3	18.8	12,694
Saudi Arabia	21,692	24,807	191.9	174.5	7,563
UAE	54,143	4,765	81.1	70.6	16,500
Total GCC	-	37,491	368.5	330.2	-
OECD	30,801	1,216,299	1080.9	8398.6	8,399

* Number for 2007

Source: World Bank; Arab Monetary Fund; Arab Union of Electricity Producers; OECD: World Bank and EIA

The consequence of the region's long-term consumption growth for electricity has been recurrent electricity shortages in recent years, with power outages and load shedding occurring along the entire Western Gulf coast with frustrating regularity between May and November, annually. Businesses and the region's energy-intensive industries make substantial losses each year during times of blackouts – the emirate of Sharjah alone, for instance, has calculated the expected losses made during its *annus horibilis* 2009 to over AED70mn (US$19mn). New electricity connections for businesses can take several months, and the shortages have impeded the development of a number of new energy-intensive industrial projects. Shortages of natural gas, the main fuel used in power generation in several GCC states, have further constrained electricity production even where enough generation capacity exists. Meanwhile, investment in new capacity has been lagging for years, a result also of missed opportunities during the 1990s and early 2000s where plans for new capacity investments did not take off. And so, the GCC states have – somewhat paradoxically – turned from the world's premier energy exporter to a region struggling with its own domestic energy demand, specifically in the area of electricity.

In this context, the GCC Interconnection Grid constitutes thus far the most ambitious and most comprehensive regional approach towards energy security among the GCC states. Hopes for a major contribution of the grid towards more system stability in the region, particularly at peak times, have of course only been implicitly made, for none of the GCC heads of states wishes to create the impression that anyone's energy security depends on a neighbouring country. In any case, the resulting 'enhanced' collective security is expectedly imperfect. The GCC states suffer from what can be called 'peak load collectivism' which implies that patterns in the Gulf states' demand for electricity, are fairly similar; peak times coincide during the summer months, when air conditioning drives up electricity demand, and in the afternoon hours. A maximum of only one hour time difference between the East and the West coast of the Arabian Peninsula further limits the variability of peak load times across the region. While there may still be space for improvement in the coming years with regards to new spare capacity coming online, there are arguably limits as to how much security of mind the GCC states can realistically expect from their new interconnection grid in the short to medium term.

There is also the separate question of whether or not the system under its current form of usage is particularly economical. Commercially speaking, the grid is clearly far from recovering its initial costs of an estimated $3 billion, excluding the still incomplete UAE–Oman link which will increase costs further for the latter two countries. The high sunk investment into the grid stands in contrast to a few, ad hoc-based and comparably small-quantity transfers of electricity so far not exceeding 1 percent of each member's total domestic consumption. Technically, the grid is hence under-utilised. None of this comes as a surprise: security of mind always comes with a cost, and while the grid in the long run may lead to some cost recovery, and perhaps even savings, in the short run no miracles can be expected.

The Potential for Regional Electricity Market Development

A more interesting question to ask, however, is whether or not in the long run the GCC grid could evolve into more than merely a security mechanism for the region's electricity producers. The grid constitutes a tool with a variety of uses, including the option of commercial trade in electricity between the GCC states. One of the most important questions GCC decision-makers will have to ask themselves in the future is whether or not they want to turn the GCC grid into a backbone for such trade, which would imply a common market for electricity in the region.

A regional electricity market in the GCC would potentially imply gains for all: electricity trade along the lines of more mature markets such as in Europe or North America suggests substantial efficiency savings can be made investment-wise; economies of scale and temporary or long-term cost advantages can be gained, on a more flexible, more reliable and effectively more efficient market. Electricity would be traded based on a cost/efficiency advantage of its utility producer vis-à-vis other regional producers, both in the short and the long term. The argument for commercial trade is particularly strong when seen in the context of many of the GCC states' declared aim of diversifying their sources of energy in power generation, towards more renewables and, in the cases of the UAE and perhaps Saudi Arabia, nuclear power. While their European counterparts are debating whether or not alternative energy and regional commercial trade can work together, the GCC states may have a unique opportunity to demonstrate their own model of sustainable energy use in combination with commercial objectives. If these are the goals of GCC decision makers, the grid's launch comes arguably at exactly the right time.

Nevertheless, the emergence of such regional trade, if desired by GCC policy-makers, and the creation of an effective regional electricity market along the lines of European and North American power markets need to be taken as a long-term endeavour which lies at best a decade away. Current market realities in the GCC states are far from fulfilling the conditions that basic regional market trading would require, most principally in the areas of overall market liquidity, diversification of energy sources used for power generation, and the thorny issue of utility sector liberalisation including domestic electricity pricing. Market liquidity is lacking most critically through the marked absence of sufficient levels of spare generation capacity in most GCC states, with Qatar currently being the only candidate with potential to export electricity at times of peak demand inside the country. In the rest of the region, peak demand consumes typically all domestic capacity, rendering large-scale commercial exports unthinkable at present.

Lack of diversity among fuel used for power generation currently prevents many of those types of cost advantages that are essential in large power markets such as in Europe. Natural gas and oil dominate the GCC power sectors as the primary source of generation, with individual small-scale renewable projects barely making a contribution. Bahrain, Qatar and Oman rely to nearly 100 percent on natural gas for power generation. Renewables and nuclear energy in particular have the potential to raise cross-regional cost advantages and efficiency savings through electricity trade. Market liberalisation in many GCC states, meanwhile, remains imperfect; despite some reform efforts, most notably in countries such as Oman and Bahrain, vertically integrated national utility companies still dominate the power sectors of Saudi Arabia, Kuwait and the UAE, limiting domestic competition and private investment.

More critically, domestic pricing of electricity remains heavily regulated, with prices subsidised below costs, effectively distorting demand and supply in many parts of the region. Recent pricing reforms in the residential sector such as in Saudi Arabia in summer 2010 have begun tackling this issue, but many Gulf producers of oil and natural gas find it politically too sensitive to change their domestic pricing structures for energy in view of their populations' expectations about low-cost energy. Many industries, such as aluminium and steel production, moreover depend with their cost advantage on plentiful and cheap electricity. Commercially traded electricity, by contrast, will be priced based on the full cost of production plus exporting company profit margins and the transmission fees for trading. Thus imported electricity will be unable to compete on prices with domestically produced power, a point which may yet prove to be one of the biggest hurdles to GCC economy trade in electricity in the mid to long term.

Political Significance

Perhaps even more than economics, the GCC grid in its current use may be seen as being politically very significant for the region. The economic integration of the GCC states has been one of the fundamental aims of the organisation since its creation in 1981. Cooperation through shared infrastructure projects, collective security efforts (including in energy), and the creation of a common market for goods and services have been objectives pursued through the decades, at times under strong criticism from within the region regarding the lack of progress in many proposed areas of such cooperation, including the failed pan-GCC gas pipeline and the as yet unachieved currency union. In this context, the GCC Interconnection Grid marks one of the few bright spots in the GCC's more recent history: it is a tangible achievement made possible by collective efforts and political will, with enormous economic potential for the long-term development of the region as a whole. Its symbolic value is thus high.

In sum, there is much to gain from the GCC Interconnection Grid if decision-makers in the region continue to unite behind the shared goal of a regional energy trading scheme. Electricity markets throughout most of the GCC states are already undergoing structural reform, and it is domestic as well as regional policy-making which will be crucial in deciding the outcome of past and current efforts with regards to GCC electricity market integration. For a European observer, the GCC experiment is in any case a worthwhile case to follow: ongoing reform and debate behind European electricity trading schemes revolve around a number of issues the GCC states yet have to face, including the necessary extent of individual countries' domestic market liberalisation and the interplay of renewable energies and commercial electricity trade – in both cases, the GCC states are likely going to see their own models evolve in the coming ten to fifteen years, provided the policy focus remains on regional energy market integration as well as domestic market reform.

This article is based on an OIES working paper by the author titled 'Interlinking the Arab Gulf: Opportunities and Challenges of GCC Electricity Market Cooperation', forthcoming in July 2011.

Oil and Gas Resources

Bassam Fattouh looks at issues and challenges facing the Saudi gas sector

Introduction

While playing a minor role in the 1970s, Saudi Arabia's gas sector has witnessed major transformations that have placed it at the centre of the Kingdom's development strategy. In a recent speech, Saudi Aramco President and CEO Mr Khalid al-Falih stated that 'the establishment of infrastructure for the gas industry serves as the basis for achieving the goal of economic diversification and provides the vital life blood for the industrial cities of Jubail and Yanbu' and most recently Rabigh'. The policy of providing cheap natural gas prices is considered by many Saudi policymakers as central to the success of the diversification strategy and to enhancing the Kingdom's global economic competitiveness as well as key for long-term political and social stability. While past policies have been successful in increasing the importance of natural gas in the domestic energy mix, they have posed some significant challenges to the current economic development strategy. These include the challenges of securing gas supplies to meet the rapid rise in domestic gas demand and reassessing the current gas pricing policy to reflect the rising marginal cost and opportunity cost of utilising gas reserves. It is now evident that the era of low-cost gas production, specifically gas associated with oil production is over. There are increasing signs that the current strategy based on (i) cheap domestic gas prices (ii) a policy of not exporting or importing gas; and (iii) meeting the rapid growth in domestic demand through increasing the pace of exploration and exploitation of domestic gas reserves is facing some serious strains. Policies pursued to deal with these strains, including doing nothing, will have wide implications not only for the future dynamics of the gas and oil sectors in the Kingdom, but also for the wider economy and the long-term sustainability of Saudi Arabia's industrialisation and development path. They also have implications for global energy markets. According to Saudi Aramco 2007 Annual Report, by meeting domestic needs for fuel, the gas sector currently frees more than 1 million barrels of oil per day for export. Thus, the policy options currently pursued to meet the challenge of rapidly rising domestic consumption and the choices made on the allocation of energy resources within the Kingdom may have an impact on global oil supplies and prices, especially if current expectations that oil markets will tighten in the future turn out to be true.

The Diversification Challenge

Despite continuing efforts to reduce oil dependency, the hydrocarbon sector still constitutes the largest sector of Saudi Arabia's economy, accounting for almost a third of the country's GDP, around 90 percent of export earnings and almost 90 percent of government receipts in 2008.

The dominance of the hydrocarbon sector extends beyond these direct contributions to economic activity. Government expenditure fuelled by oil revenues is the main driver of public and private consumption. Direct government services are the second largest contributor to economic output after the hydrocarbon sector accounting for 17 percent of GDP. Government spending is also the main driver of private consumption as the public sector is a key employer of Saudi nationals. In 2008, the public sector employed around 20 percent of the Saudi national workforce. Government spending fuelled by hydrocarbon revenues is also the main impetus behind the growth in the private sector and non-oil output. Recent evidence indicates that apart from their effect on government expenditure, high oil prices do not exert an independent influence on underlying non-oil output in oil-rich economies.

The diversification of the economy has been a top priority for Saudi Arabia. Diversification is considered as key for achieving the goals of sustainable and stable growth, enhancing the role of the private sector, and generating employment. Diversification is also perceived as essential to enhance the Kingdom's integration into the global economy via channels other than the export of crude oil and petroleum products. A central pillar of the diversification strategy centres on the establishment of export-oriented industries that feed on relatively cheap energy sources and that capture the value added of energy resources through extending the energy chain into downstream activities.

The Evolution of Domestic Gas Demand

With the Master Gas System coming on-stream in the early 1980s, the position of natural gas in the energy mix was transformed. From around 25 percent in 1980, the share of natural gas in total domestic energy consumption continued to rise over the years reaching 45 percent in 2004 and declining slightly to 43 percent in 2008. While in 1970 annual consumption of natural gas amounted to less than 2 billion cubic metres (bcm), in 2009 Saudi Arabia consumed around 77.5 bcm. The Ministry of Petroleum and Mineral Resources estimates that demand for natural gas will rise threefold between 2005 and 2030.

The rapid growth in domestic gas consumption can be explained by many factors, such as improvements in income levels, a rapidly expanding population, cheap gas prices and industrial policy. Regarding the latter, the policy of providing cheap feedstock to petrochemicals constitutes a key element in fostering the Kingdom's competitiveness in global markets. The Saudi petrochemical industry has witnessed very rapid expansion – accounting for 9 percent of the economy's output in 2008. Its transformation at the global level has been immense. From being a net importer in the 1970s, the Kingdom currently accounts for almost 7 percent of the global supply of petrochemical products. Nevertheless, the petrochemical sector currently employs around 90,000 employees who constitute only around 3.8 percent of the Saudi workforce or 1.2 percent of the total workforce. While extending the energy value chain can in principle help develop more labour-intensive industries, the ability to exploit these opportunities would depend in large part on the dynamism and competitiveness of the private sector and the skills of the domestic labour force.

Another important dimension is the growth in electricity demand. The combination of a general improvement in the standard of living, a fast expansion of the industrial base and low electricity prices has contributed to a rapid increase in electricity demand over the years. Per capita electricity consumption in the Kingdom more than doubled from 2967 kWh per year in 1984 to more than 7000 kWh in 2007, an average annual growth of 3.7 percent during this period. The last three decades witnessed a rapid expansion in power generation with capacity increasing from around 7 Gigawatts (GW) in 1982 to almost 33 GW in 2007 with the average annual growth between 2000 and 2007 exceeding 6 percent. The Ministry of Water and Electricity expects the power generation capacity to double to 60 GW by 2023. In the original plan, natural gas and/or combined cycle were expected to drive this power generation capacity expansion. However, there has been a change in policy. In 2006, the government issued a Royal Decree stating that the country's largest future power plants – which were initially planned to rely on gas – will be fired by heavy fuel oil provided at a heavily subsidised price. Thus, in the absence of large gas finds or gas imports, the requirements of any future expansion in power generation and water desalination will be met by liquid fuels, reducing the share of gas in power generation, contrary to the general trend in the rest of the world.

Pricing Issues

Natural gas prices for domestic use in Saudi Arabia have exhibited remarkable stability. In 1984, the government set natural gas at the price of $0.50 per MMBtu. This price was maintained until 1998 when it was revised upwards to $0.75 per MMBtu. To many analysts, the provision of natural gas at a price below the international or regional price constitutes a classic case of a subsidy. However, this issue needs careful analysis in the Saudi context. First, in order to identify whether a subsidy exists, it is important to compare the price charged to domestic consumers with some measure of cost. There is more than one concept of cost: the average cost, the marginal cost and the opportunity cost. The first refers to the overall cost per unit of output and is measured by the sum of average fixed costs and average variable costs. The marginal cost is the increment in total cost resulting from a unit change in output. In sectors such as oil and gas that require heavy capital investment, the average cost and the marginal cost are often very different. While the average cost in these sectors can be high, the marginal cost is comparatively very low. The opportunity cost on the other hand is not related to production costs. Instead, it measures the forgone value of the resource when that resource is not utilised in its best alternative use, e.g. its value in international trade if it can be exported.

During the 1970s and early 1980s, most of the gas produced was in association with crude oil and NGLs. Given that crude oil was the most *sought-after* item, until very recently gas was treated by the government as a (free) by-product. Consequently, one could argue that the cost allocated to gas production should be set to zero or at most the cost involved in construction and operating the infrastructure needed to capture, treat and distribute the associated gas. Thus, at the early stages of the development of the gas sector, the concepts of average and marginal costs were not relevant. The concept of opportunity cost for natural gas was also irrelevant, as Saudi Arabia does not have the infrastructure to export its associated gas. (This raises the issue of whether Saudi Arabia should aim at exporting gas, especially that the current policy of diverting gas to petrochemicals and energy-intensive industries has had so far limited impact on diversification and employment generation.)

As the demand for gas increased over the years, the Kingdom has been under pressure to expand its gas supplies by exploring and developing its non-associated gas fields. This implies that the concept of marginal cost (i.e. the cost of producing an additional 1 cubic metre of gas to satisfy the rising demand) is relevant. However, even in what seems to be a clear-cut case, it is possible to argue that the most *sought-after* item in the new projects is NGLs while the natural gas itself can be considered as a (free) by-product. Given the large spare capacity in liquids, the rapid increase in gas demand, and the recent plans to develop non-associated gas fields (Karan, Arabiyah and Hasbah) it is more appropriate to consider that the most sought-after product is natural gas. Hence, the cost of bringing additional gas supply from more difficult fields, i.e. the marginal cost or the average cost, should be the relevant concepts of cost. The (long-term) marginal or average cost is expected to exceed the current gas price sold to domestic users.

When it comes to power generation and water desalination, the issues are strikingly different and the concept of opportunity cost becomes highly relevant. The rapid increase in energy demand has pushed the Kingdom to resort to burning crude oil/fuel oil in power generation and water desalination plants while diverting natural gas to the petrochemical sector where substitutes are limited. According to the *Financial Times*, Saudi Arabia will be burning directly nearly 600,000 b/d of crude oil this summer for power generation while the IEA estimates that the Saudi direct burn of oil for power has reached about 450,000 b/d in 2009 increasing from 200,000 b/d in the early 2000s. These potentially exportable fuels are provided at a fraction of international prices and hence using these liquid fuels domestically involves a substantial opportunity cost.

> "by meeting domestic needs for fuel, the gas sector currently frees more than 1 million barrels of oil per day for export"

Given that Saudi Arabia sits on large spare capacity, the crude oil used in power generation is not destined for exports. Thus, some would argue that the alternative uses of crude oil in the presence of spare capacity are either to leave it in the ground or use it in power generation and water desalination plants. According to this view, the benchmark that should be used in measuring the opportunity cost is not the export price. A natural extension of this argument is that the existence of spare capacity implies that the domestic use of crude oil even at prices below international prices has no opportunity cost. On the contrary, since maintaining spare capacity entails a positive cost then all crude oil not sold internationally should be domestically utilised.

This view however suffers from three major caveats. First, given that OPEC policy is set in terms of production quotas rather than export quotas an increase in domestic oil consumption reduces the country's oil export potential. Second, the availability of spare capacity fulfils a key role in stabilising oil prices in periods of disruption and large shocks to the market. This gives Saudi Arabia a unique position in international energy markets, a position which extends beyond the oil market into the international economic and political spheres. Thus, the reduction in spare capacity due to an increase in domestic consumption implies a positive (though difficult to measure) opportunity cost. Third, the above analysis does not take into account inter-temporal choices. The owner of the resource has two options: either to extract it today or to keep it in the ground for future extraction. Any amount extracted today is not available for extraction in the future. If the price of oil is expected to rise in the future, then the owner has the incentive to hold on to the resource and sell it at a higher international price in the future. So the benchmark that should be used in measuring the opportunity cost in the presence of spare capacity is the future price of oil.

In short, the gas pricing issue requires careful analysis that takes into account a number of factors including the choice of the relevant concept of cost, the availability of spare capacity, and the phenomenon of joint products. However, regardless of the concept of cost used, it is clear that the current gas pricing policy involves a large opportunity cost and needs to be reconsidered. Furthermore, cheap gas prices intensify the gas supply–demand gap by encouraging demand growth and limiting potential supply responses by reducing the incentive for exploration and development and investment in domestic gas infrastructure.

The Supply Side: Patterns and Challenges

Given the strong pressures on the demand side, the Kingdom has pursued a strategy of initiating an aggressive exploration and development of its gas reserves, which in 2009 were estimated at 7.92 tcm accounting for around 4 percent of the world's proven reserves. The future success of such a supply strategy depends to a large extent on the prospects of discoveries in the

Empty Quarter. However, hopes of transforming the Empty Quarter into a non-associated gas-producing region seem to be fading. Consequently, the Kingdom has decided to turn its attention to developing more challenging onshore and offshore fields. The Karan field, the first non-associated offshore gas increment in the history of the Kingdom, has been fast-tracked to be completed in 2012. The sense of urgency has also pushed Saudi Aramco to fast track the development of other offshore non-associated gas fields such as Arabiyah and Hasbah. One distinguishing feature from the past is that these offshore non-associated gas fields with high sulphur levels are more expensive to develop while Saudi Aramco is committed to sell gas to its domestic customers at a fraction of the development costs.

Conclusions

Rather than widening its options to deal with the 'gas challenge', Saudi Arabia is likely to continue with its main strategy based on expanding its gas reserves to meet the expected growth in domestic demand. However, there are signs that the current strategy is facing some strains. Unlike other countries, the Kingdom is fortunate in that it can always rely on its massive oil reserves to continue with the current policies and to hedge against the potential failure of achieving self-sufficiency in gas. However, this would be far from ideal and such a policy would involve serious political and economic costs. It is the ability of the policy-makers in the Kingdom to show a greater degree of flexibility and to make some hard choices today that will ultimately determine the evolution of the gas sector in the next few years and with it the country's economic path ahead and Saudi Arabia's future position in international energy markets.

James Henderson considers the strategic implications of Russia's eastern oil resources

The hydrocarbon potential of Russia's eastern regions has been apparent since the Soviet era, when the authorities imagined that oil and gas production from the area would supplement and ultimately replace West Siberian output. However, the remoteness of the region, a lack of funds and the continued success of the oil and gas sector in the west of the country meant that it was not until the 1990s that serious exploitation of eastern fields was initiated, and even then the original Sakhalin 1 and 2 projects remained Russia's only significant eastern oil and gas investments until 2008.

However, the region has now become a strategic priority for Russia's oil and gas sector, mainly because the Russian administration, concerned about the lack of economic development in the east of the country and the potential for oil production decline in West Siberia, has started to provide significant investment incentives. Major infrastructure, in the form of the East Siberia Pacific Ocean (ESPO) pipeline, has been built by state company Transneft to provide 600,000 b/d of current export capacity, rising to a potential 1.6 million b/d over the next decade, direct both to China and to the broader Asia-Pacific markets. Tax incentives have also been introduced, with a particular focus on reduced rates of export tax providing a major boost to the economic returns from East Siberian fields. These tax breaks remain short-term at present, reducing the economic security for investors in new fields, but a current review of the country's oil tax system could provide greater long-term direction by the end of 2011.

Importantly, though, investment is also being encouraged by the rapidly growing demand for Russian crude in Asia-Pacific markets, which has now reached a level where previous political obstacles to interaction with Russia have been overwhelmed by the commercial necessity of securing a diversity of oil imports. Most importantly, China's relationship with the Russian oil sector was sealed with the $25 billion loan offered to Transneft and Rosneft in 2009, and it will now receive at least 300,000 b/d of crude over the next 20 years via a direct pipeline link. Other Asia-Pacific countries are also now viewing Russian ESPO crude, purchased at the eastern port of Kozmino Bay, as a welcome source of diversification from Middle Eastern and West African imports, which is particularly important as the Asia-Pacific region's oil import requirement is expected to grow at 2.5 percent per annum over the next twenty years.

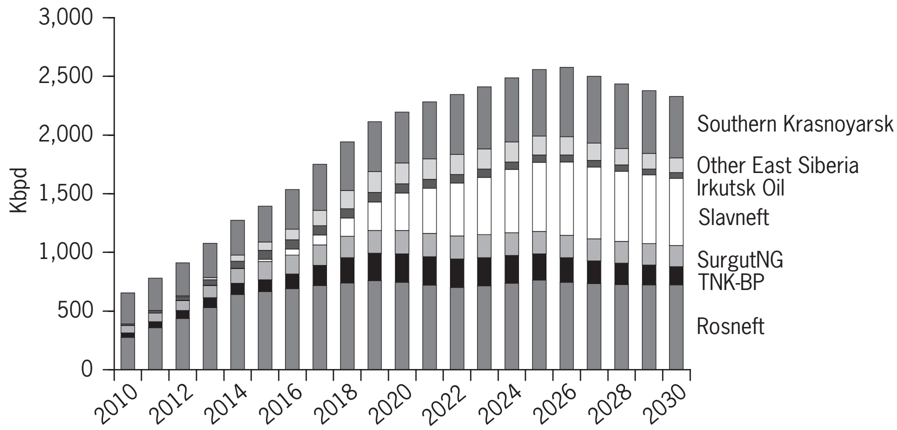
This new demand for Russian crude on the East will be met from five core hydrocarbon regions in Eastern Russia, which have the potential to produce over 2 million barrels per day of oil by 2020 and 2.5 mmb/d beyond that. As shown in Figure 1 the major short-term growth in Russia's east-facing production is likely to come from the Yamal-Krasnoyarsk region in the north-west of East Siberia, where Rosneft's major Vankor field is located. Vankor production is set to reach a peak of 510,000 b/d within the next two to three years, and output from the region is likely to be supplemented over time by new discoveries as well as by fields in nearby Yamal where TNK-BP and Slavneft have significant reserves awaiting development. Currently identified assets could see regional output grow to 750,000 b/d, with new infrastructure providing spare capacity for potential new discoveries and the flexibility to send oil both east via the ESPO and west via the existing Transneft pipeline system over the next two decades.

Further east the Irkutsk region is likely to be the area of fastest output growth in Russia over the next decade, driven by the exploitation of Rosneft's licences around the existing Verkhnechonskoye field. An initial 1 billion barrel discovery has already been made and total resources in the region are estimated at 8 billion barrels, with production potentially reaching 400,000 b/d by 2020. Directly north of Irkutsk the Sakha region also has significant growth potential based on the assets owned by Surgutneftegas around the Talakanskoye field, and the company's strategic ambition to grow its output in the area could see output triple to 200,000 b/d by 2020.

Oilfields in Southern Krasnoyarsk also offer the potential to create a major hydrocarbon centre, with initial development likely to be focused on Rosneft's Yurubcheno-Takhomskoye field. However, of all the onshore regions identified so far Southern Krasnoyarsk is furthest from the ESPO and therefore will require the greatest expenditure on new infrastructure. As a result it is unlikely that the region will be fully developed before 2020, but output could still reach 350,000 b/d beyond that date. Finally, although Sakhalin Island has been the main source of East Russia oil production over the past two decades, its relative importance is now likely to decline as the major East Siberia fields are developed. Nevertheless ongoing development of the Sakhalin 1 project and continued exploration activity could still see output reach 500,000 b/d by 2020.

From a corporate perspective state company Rosneft is set to be the driving force behind the growth in Russia's eastern production growth

Figure 2: Eastern Russia Oil Production by Company

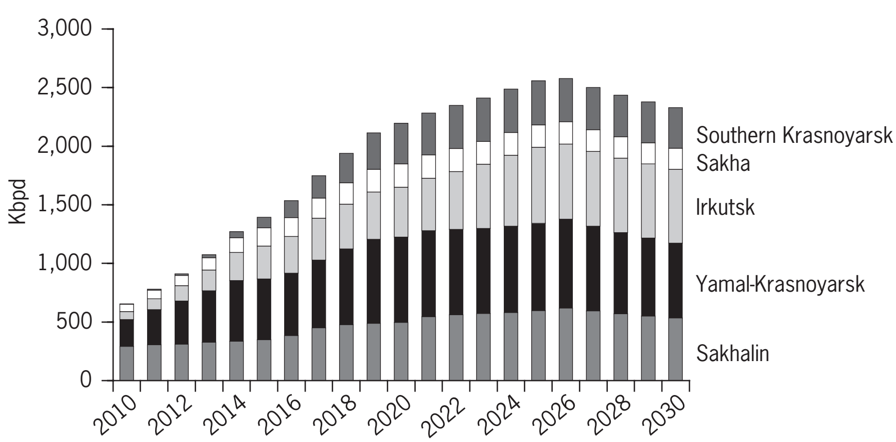


Source: Author's Estimates based on Company Data

over the next two decades (see Figure 2). The company has significant positions in four of the five regional areas discussed above (with Sakha being the current exception) and could see its output from Eastern Russia triple to 750,000 b/d by 2020. TNK-BP and Surgutneftegas are the other main producers at present, and both have growth potential based on their existing fields and new developments. TNK-BP's Verkhnechonskoye field should reach peak output by 2017, by which time the company's fields in the Yamal-Krasnoyarsk region should also be onstream, leading to overall eastern output of up to 250,000 b/d by 2020. Surgutneftegas, on the other hand, is likely to remain focused on the Sakha region, where the eight fields it owns on the tax-exempt list could lead to output of 200,000 b/d on a similar timescale. However, the company with the greatest growth potential is Slavneft, jointly owned by GazpromNeft and TNK-BP, which has exposure to large fields in Yamal-Krasnoyarsk and Southern Krasnoyarsk. All of its assets are dependent on the construction of new pipelines, but the new political and corporate focus on Russia's East means that the momentum to build the infrastructure that will enable commercial development of new fields is strong. As a result the company could go from zero eastern production to output of over 300,000 b/d by 2020, with the potential to double that figure again by 2030 if its main fields are developed.

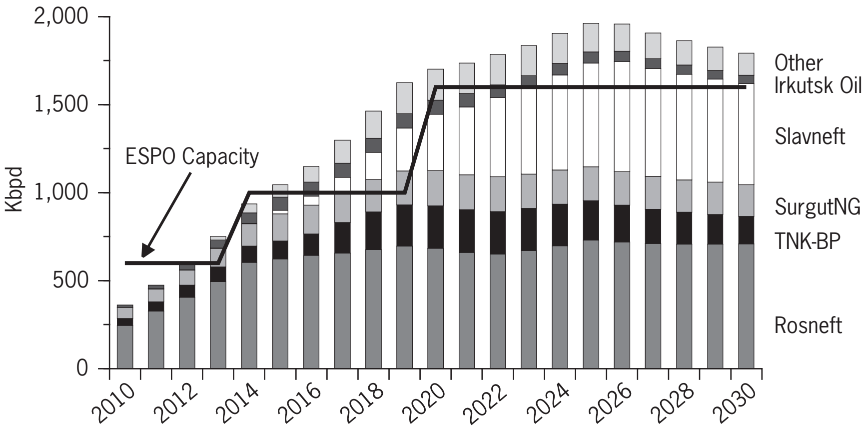
However, while the potential for oil output in Russia's eastern regions is clearly large, it would be wrong not to acknowledge some important risks to the development of that potential. The most obvious risk is the ongoing difficulty presented by the regions' geography and geology. Despite the building of the ESPO, transport infrastructure remains scarce, and when this is combined with the extra cost of importing oil service equipment and personnel the commercial returns from any project can be quickly undermined. Furthermore, the formation of many of the oilfield reservoirs in East Siberia is different

Figure 1: Future Oil Supply Potential from Eastern Russia



Source: Author's Estimates based on Company Data

Figure 3: Eastern Siberia Oil Production and ESPO Capacity



Source: Author's estimates

to those seen in the west of the region, again with potential consequences for cost and exploration risk.

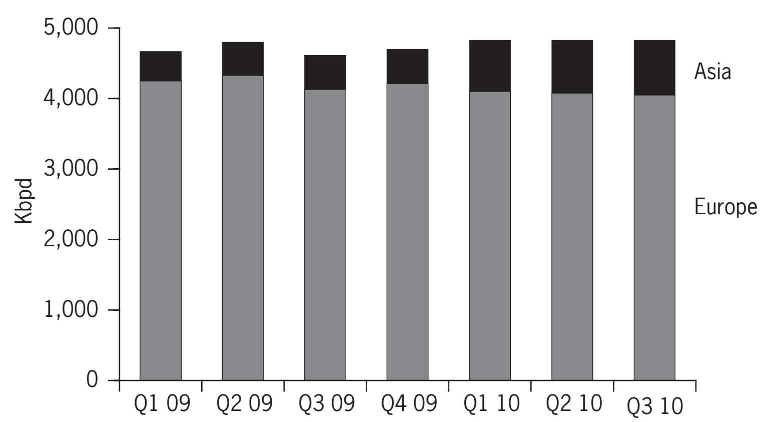
However, these challenges, or at least the cost of them, can be alleviated by the introduction of a tax system that incentivises investment and risk-taking. Until 2009 East Siberia fields were taxed in the same way as the mature producing assets in West Siberia, with the main element of the tax system being two revenue-based taxes, MET and the Export Duty. Following a series of changes during 2009 and 2010, 22 East Siberian fields now pay a reduced export duty and zero MET, but the tax that is paid is still largely revenue based and does not allow for the cost recovery that is essential to the economics of new fields. As a result, companies are still questioning the true economic incentive to invest, especially as the tax breaks are removed when a 15 percent IRR cap has been reached. Furthermore, the potential for further changes in the tax system is high, as a debate about the whole structure of oil taxation in Russia is ongoing, with the oil industry pushing for a lower tax burden but the Ministry of Finance arguing for increased tax revenues in order to maintain Russia's fiscal stability during the current global economic crisis.

A broader risk is that the incentive for Russian oil companies to send oil east rather than west may not fully materialise due to political factors, such as Russia–China relations breaking down, or commercial factors such as disagreements over oil prices. However, the commercial reality of growing oil demand in China and the Asia-Pacific region as a whole combined with the potential for growing supply in Russia would appear to provide a strong basis for believing that the export-import trade in oil and oil products will increase rapidly. Infrastructure issues will be resolved as the industry grows, geological risk is unlikely to prevent long-term development given the progress already made at a number of fields and licences, and the Russian government is likely to continue to provide tax incentives as its eastern regions will remain a vital strategic priority for decades to come. Therefore, although the development of any new hydrocarbon province is never without significant risks, the commercial logic behind the development of hydrocarbons in East Siberia would appear to be strong enough to mitigate their likely impact.

It appears, therefore, that Russian oil companies, led by Rosneft and encouraged by the incentives offered by the Russian government, are increasingly focused on developing the oil resources of East Siberia and Russia's Far East. Further, it would also seem likely that the resources are technically available in the region to generate a significant boost to production, with a theoretical potential as high as 2.5 mmb/d, if a reasonable amount of exploration success is assumed. As a result, even allowing for production from Sakhalin Island of up to 500,000 b/d, it is not hard to create a scenario in which the full 1.6 mmb/d export capacity of the ESPO pipeline is filled by 2020 (see Figure 3).

As a result it would appear very likely that the Russian government's target of 1.5 mmb/d of East Siberian oil production by 2030 (as stated in its most recent Energy Strategy) can be met or even exceeded, and that this growth will enable Russia to maintain its overall oil output at or above 10 mmb/d. Furthermore, it also seems very feasible to assume that Russia's

Figure 4: Russia Crude Oil Exports to Europe and Asia



Source: Energy Security Analysis Inc.

oil exports to Asia will increase along the same trajectory towards the government's target of 1.3 mmb/d by 2030. Indeed it is interesting to note that oil output from East Siberia and Russia's Far East is already playing a key role in maintaining the country's oil production and exports. In 2010, for example, overall Russian oil production rose by 2.2 percent from 9.92 mmb/d to 10.15 mmb/d, an increase of 230,000 b/d, while over the same 12-month period production from East Siberian fields rose by 237,500 b/d, accounting for 103 percent of Russia's total production growth and demonstrating that the region is already making up for declines elsewhere in the country.

A similar story is also emerging in terms of Russia's crude exports. Figure 4 shows that prior to the start-up of the ESPO in December 2009 Russia was exporting between 400–500,000 b/d of crude to Asian markets via a combination of tankers from Sakhalin Island and rail transport to China. In 2010 the level of exports jumped by almost 300,000 b/d as the ESPO opened as far as Skovorodino, allowing onward transport of crude to Kozmino Bay on the Pacific Coast. From January 2011 ESPO exports will jump by up to a further 300,000 b/d as the spur pipeline from Skovorodino to the Chinese border also becomes operational, and as a result it is again apparent that exports from Eastern Russia to Asia have already started to replace the declining sales to Europe that can be seen appearing through 2010. Although the effect is only marginal at present it is expected to accelerate over the next three years, with exports to Europe estimated to decline by 600,000 b/d between 2009 and 2014 while exports to Asia should have increased by around 800,000 b/d over the same period. It would therefore appear that crude from Russia's eastern regions is likely to have an important role not only in bolstering Russia's oil production and exports over the next two decades but also in encouraging a further shift in geo-political focus away from Russia's traditional western customers towards the emerging energy markets of the Asia-Pacific region.

Juan Carlos Boué assesses the importance of recent Brazilian oil discoveries to the global petroleum industry

In recent years, the Brazilian upstream sector has become the focus of intense interest on the part of petroleum industry observers. Amidst sharp output declines in many basins that have been key bulwarks of the oil and gas markets (Mexico, Alaska, the North Sea), the Brazilian deepwater offshore had arguably been one of the brightest spots for worldwide exploration activities in terms of discoveries and additions to reserves, even before the announcement of hitherto unsuspected and seemingly gigantic fields in structures located underneath enormous autochthonous salt layers deposited in Cretaceous times.

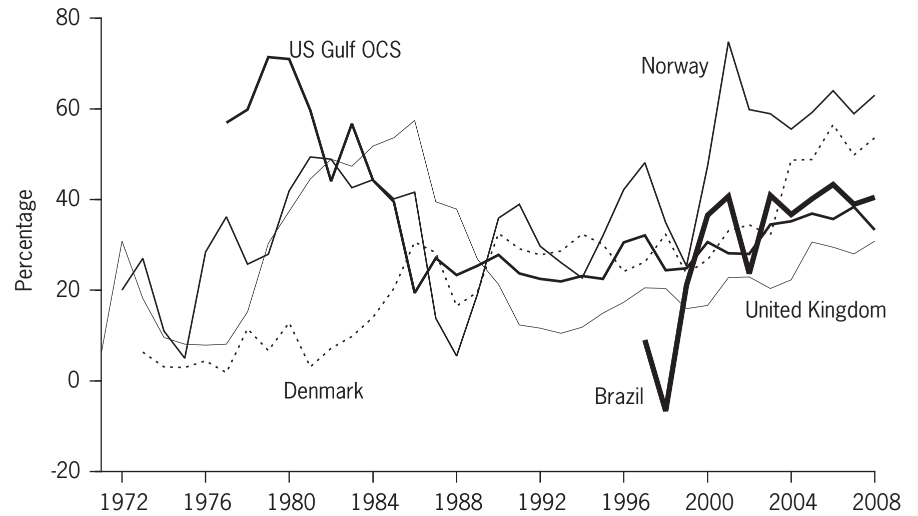
For Brazil, the discovery of this subsalt oil province seems to have come at a particularly auspicious time. The country's economy, already on the ascendant before the Global Financial crisis of 2008, shrugged off the effects of this event, and continues going from strength to strength (not least because Brazil is by a long distance the largest recipient of direct foreign investment in Latin America). Brazilian energy policy has been an important contributor to this success story. Over a period of time when many countries worldwide have had to struggle with high oil and gas prices as well as serious concerns over security of supply, Brazil managed not only to reduce its very large oil import bill but actually to become a significant net oil exporter. Furthermore, high oil prices (not to mention the emergence of global warming as a policy problem) appear to have vindicated in full the costly strategic initiatives that the Brazilian state steadfastly clung to even during times of abundant oil supplies, notably the massive biofuels and deep water exploration programmes. Indeed, at this point in time, Brazil looks to be standing just below the cusp of a development promontory whose climbing has been both long and difficult, and whose surmounting is expected to lead to alleviating (if not ending) the abject poverty which still afflicts the majority of Brazilians. Crucially, in the eyes of the administrations of presidents Lula da Silva and Rousseff, Brazil's oil resources (and, more specifically, its pre-salt fields) are nothing less than the golden ticket that may open the gates of the promised land, not least because they are expected to allow Brazil to join the club of major oil exporters.

As important as the outlook of the Brazilian upstream is to Brazilians, a lot is also riding on it as far as the global petroleum industry is concerned. For one thing, international oil companies view Brazil as a privileged destination for their investment funds, in light of its excellent prospectivity, its openness towards foreign upstream investment (quite lacking in many otherwise attractive places), its enormous domestic market, its seemingly stable institutional framework and its favourable fiscal regime. For their part, global oil consumers are counting on the aggressive development of Brazilian oil and gas resources to take at least some of the edge off the very high prices that have materialised in the wake of production declines elsewhere, and hopefully to curb the market power of OPEC nations (and Russia). Finally, the management of Petrobrás is very eager to fulfill these expectations, seeing in them the chance to turn the company into one of the international super majors, even if this implies carrying out a massive development programme, the likes of which would strain the management and financial resources of the very largest among its peers.

Notwithstanding the rather fanciful nature of the Brazilian reserves estimates that have been bandied about thus far (especially by *Agência Nacional do Petróleo, Gás Natural e Biocombustíveis* ANP), there can scarcely be any doubt that Brazil will be a major player in the oil industry in years to come. Having said that, the near universal bullishness about Brazilian upstream prospects seems overdone, not least because what questioning there has been regarding the likelihood of the various Brazilian oil output scenarios (and there has been very little of that), has involved strictly technical aspects, mostly having to do with geology. In other words, it has tended to assume that the binding constraint for the development of new Brazilian fields will come in the form of underground factors. This is remarkable, given that over the past ten years or so, it has been overground (i.e. political and institutional) factors that have been behind the slowing down (or even the reversal) in the rate of output expansion in countries such as Russia and Venezuela. In economic terms, the tangible manifestation of these overground factors has been a grossly asymmetrical distribution of upstream proceeds between host governments (in their capacity as representatives of the owners of the natural resources being exploited), on the one hand, and the firms exploiting the resources, on the other. This imbalance became increasingly intolerable as oil prices rose, leading to the outcome that the governments involved devoted (and in places like Kazakhstan, continue to devote) most or all of their scarce expertise and manpower to restructuring legacy projects, as no new project can offer a better payoff than levying more reasonable taxes on indefensible contracts. This focus on restructuring (and its almost inevitable sequence, litigation) will, in the foreseeable future and in quite a few places, continue to snarl up the smooth flow of investment capital, which is a prerequisite for lower volatility and fair and sustainable prices.

These reflections are very pertinent to the case at hand because Brazil appears to exhibit many if not all of the economic symptoms that have triggered contract restructurings in places like Venezuela. As Figure 1 shows, on the basis of figures compiled for the period 1971–2008, it is difficult to avoid the conclusion that Brazil is a relatively undertaxed petroleum province, whose fiscal regime produces outcomes in terms of government take that resemble those of provinces where fiscal income considerations are not very important (notably the US Outer Continental Shelf and the UK Continental Shelf). This is not very surprising, given that the Brazilian upstream fiscal regime was designed at a time when the country was still a very substantial oil importer, and maximisation of domestic production was a weightier strategic imperative than fiscal revenues. Having said that, there are distinct indications that the Brazilian government is not completely happy about the behaviour of its petroleum fiscal income, notably the partial or total cancellation of two out of the last three acreage bidding rounds (the 8th and 10th), and its desire to adopt a completely new fiscal and contractual regime for pre-salt fields. Moreover, the institutional situation in Brazil seems particularly fraught because at its very centre is the Brazilian national oil company, Petrobrás, majority owned by the government. Quite apart from whatever organisational diagrammes might purport to say, the *de facto* licensing agency for the Brazilian upstream - particularly at the level of determining the rate of extraction and depletion of Brazilian hydrocarbons resources - is Petrobrás (rather than the ANP). Furthermore, one of the key roles for Petrobrás has been that of controlling its home government and majority owner. Thus far, the company has excelled at this particular function, as witnessed by the way in which it managed, firstly, to convince the government to make it (on a statutory basis) the preferred operator in the presalt; secondly, to adopt a contractual form and fiscal regime for the presalt which are likely to diminish further the government's per barrel take (if precedent from other countries is anything to go by), and, last but by no means least, to transfer to it (as an equity contribution in exchange for shares) title to a very large amount of reserves at an extremely advantageous price. However, Petrobrás flawless past performance is no guarantee of future performance, which should give observers of the Brazilian oil industry pause for thought, not least because outright conflicts involving governments, on the one hand, and their national oil companies, on the other, have culminated in especially messy outcomes (nowhere more so than in Venezuela).

Figure 1: Government Take as a Percentage of Upstream Income in Selected Offshore Petroleum Provinces 1971–2008



Asinus Muses

Rating the Raters

August was a cruel month. Rather than sit back and enjoy their holidays like sensible folk, ratings agency Standard & Poor's took the radical step of downgrading US government debt. But what looked like a bad moment for the US government quickly became an embarrassing one for the ratings agencies. Readers may recall the role of these agencies in the financial crisis, stamping the most toxic subprime mortgage derivatives with the sure-thing AAA label, and rating Lehman Brothers A or better right up until it declared bankruptcy in September 2009. Investors now take the agencies so seriously that they do precisely the opposite of what they recommend, responding to the downgrading by buying so heavily that US long-run interest rates collapsed to levels seen in late 2008, their lowest since Asinus's data source started counting in 1962.

Stock markets, correspondingly, took a nosedive, with the S&P 500 losing fully one-sixth of its value from early July to early August. Oil prices followed suit with WTI dropping 20 percent from peak to trough. While Brent held up a little better, otherwise the story on this side of the Atlantic was virtually identical: the FTSE 100 followed the S&P 500, and UK government bonds have followed exactly the trajectory of their US counterparts, with interest rates plummeting to historical lows. Indeed, bonds all the way up to seven-year maturities don't even keep up with the 2 percent inflation target. Given the reverse-psychology of Standard and Poor's in US debt markets, Asinus is dubious of Chancellor of the Exchequer George Osborne's argument that the agency's positive outlook on UK policy is something to be proud of.

Cuts: Investment and Power

Politicians love to use the metaphor of household finances for government finances, at least when it suits them. To a macroeconomist (and Asinus has some such pretensions) this feels a bit like an astronomer would feel hearing the government Chief Scientist base space exploration policy on astrology. But they are not even consistent in their illogic: if a household's roof is leaking or, let's say, their electrics don't work, then a period of miniscule interest rates seems the obvious time to borrow for investment. Yet in both the US and the UK government investment is being cut back. Asinus has just read that Disney is making the most of the situation by issuing over $1 billion of long-term bonds at record low interest rates. Apparently Mickey Mouse has a better grasp of basic economics than our political leaders.

If what passes for the political class in the US cannot think of any public investments that offer at least a 2 percent return, Asinus would like to humbly propose the power sector. According to Professor Massoud Amin, the US electrical grid has been suffering more and ever-worse blackouts over the past 15 years, now averaging 92 minutes per year in the Midwest and 214 minutes in the Northeast. Japan, known to all conventional wisdom as an economic basket case for the last 20 years, loses an average of only 4 minutes of power each year.

Lone Star Miracle

Take Texas, whose laissez-faire governor and presidential aspirant Rick Perry claims to have performed a 'miracle' with his state's economic recovery, achieving an unemployment rate only a bit worse than in New York (and considerably worse than in Massachusetts). Texas has declared its fifth 'energy emergency' this year, announcing rolling blackouts as its power infrastructure fails to keep up with the great state's great demands.

Rebels Without a Cause

In contrast to Texas's power outages we in the UK seem to have experienced an excess of another kind of energy, with an explosion of rioting and looting in major cities. Were they protesting at economic turmoil? Did they chant slogans demanding government action on high unemployment and inflation? Not quite. Asinus has been comparing the English Summer with the Arab Spring. Arabs took to the streets to fight for democracy and human rights, while the English took to the streets to fight for their right to Nike trainers and G-Star jeans. It was not so much banks or public buildings that suffered their ire, but shops selling consumer goods, to the point that someone coined the elegant term *shopping with violence* to describe events. But before we over-romanticize their lot and under-romanticize our lot, Asinus would remind readers of two things. The Arab protests started over the right to sell vegetables in the street; and it seems doubtful that the English rioters would have displayed so much aggressive exuberance had not the erstwhile irrational exuberance of the financial world left so many of them out of work and with nothing better to do.

Warming Thoughts

As the rich world slides into decadence, middle-income countries have been raising investments in renewable energy. China leads the world at $49 billion in 2010, with other emerging economies posting large rises. None too soon, since the Carbon Tracker Initiative has argued that current proven reserves of fossil fuels represent carbon emissions equalling five times the limit that climate change scientists have set the world all the way up to 2050. Asinus hopes that the current cooling of the economy may at least slow the warming of the planet.

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