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Spring 2005 has encouraged us to look at the nuclear energy option. We are not alone in this reappraisal of an alternative which has for many years been discarded by public opinion as worth no practical consideration. Whether or not the public, however defined, has changed its mind about nuclear is uncertain, but energy planners and analysts have, for various reasons, reopened their files and environmentalists find the need to make a balance between CO_2 emissions and nuclear waste concerns.

IAEA seems the logical place to start, and we are indebted to David Waller and Alan McDonald for introducing the subject. They remind us of the rationale for the renewal of interest: nuclear is a safe alternative (in spite of its Chernobyl reputation), there is increasing pressure on traditional energy sources, diversification is important to large consumers and the environment is at the top of most agendas. Nuclear today provides 16 per cent of the world's electricity and there are nearly 450 nuclear power plants in operation – it is not a dead industry as many imagine. They are, nevertheless, cautious about the future; they show confidence that the share of nuclear is unlikely to diminish and will, indeed, increase, but it will be a controlled and specific expansion.

Judith Greenwald concentrates on the challenge of CO_2 emission reduction in making a similarly cautious claim for nuclear as part of the solution for the USA. There the future of nuclear is more acutely under threat in that, while 20 per cent of US electricity supply comes from nuclear, 40 per cent of that capacity will be retired by 2015. The industry is faced by universal problems linked to waste disposal and proliferation, the economics of nuclear plants and political influences, but the demand for CO_2 reduction is playing an increasing part in the formation of public perception. What is needed is international coordination and cooperation in finding guidelines for nuclear development. For the USA, while nuclear still remains an important component of the energy mix, its future, however logical or desirable in terms of a low-carbon environment, is subject to much political, social and economic interplay.

Paul Mobbs introduces a different constraint into the debate. Many of us will have accepted, perhaps without much thought, the general proposition that uranium is found

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in so many places that nuclear power will never find itself short of fuel. Mobbs points out that in practice this is not the case; that the concentration of uranium is critical, as is the type; and that the amount of uranium required depends on the type of reactor. He also states that, if nuclear is to provide a larger proportion of the world's total energy supply, nuclear energy must increase by a factor of 4–8 times in order to make a significant difference to the use of fossil fuels. In these circumstances the lifespan of the known available uranium resources would be dangerously reduced for the continuing operation of the nuclear plant implied. This may seem a peculiarly esoteric argument in the current debate, when it seems to require superhuman effort to agree to the building of even one plant, but it is surely preferable to be sure of the resource before it might be needed.

From nuclear we move to look at mainly non-OPEC oil production in two regions outside the Middle East – West Africa, which has been seen by some as a particularly hopeful area for new oil supply, and South America. Clearly the international system needs a boost from outside the Middle East in the medium and longer term and, in spite of intermittent optimism attached to Russia, other regional expectations would be welcome.

Andrew Hayman analyses the West African scene, but finds that in the period up to 2010 there is unlikely to be any major excitement. Nigeria may increase production by 1 mb/d and Angola by 0.5 mb/d; Equatorial Guinea may reach 0.35 mb/d, but the rest have limited potential. The region is unlikely to produce more than 6.5 mb/d by 2010 (including OPEC Nigeria), but that will be a valuable addition to world supply.

Ivan Sandrea has done the same for South America, excluding OPEC Venezuela. Here the picture is dominated by Brazil and seems unlikely to add much to a regional production hovering around 4 mb/d in the period to 2010. What is lost in the rest of the region will hopefully be replaced by additional Brazilian production. Sandrea shows, however, the extent to which Brazil is the key player, and the technical and managerial problems that it must overcome. The longer-term predictions are not very favourable for the region.

Our other main article concerns Gas in India. Chris Hansen analyses the role LNG may play provided that the central government and regional policies give it room to manoeuvre without imposing political or economic constraints. He looks at the possibilities of imported pipeline gas from Myanmar or Iran and domestic gas from new discoveries. He also deals with the complicated pricing sensitivities around gas, and concludes that the major determinant may be the regulatory and taxation regime.

Personal Commentary is by Walid Khadduri, who looks at what OPEC policy has been in practice as opposed to what some critics have claimed for it. OPEC has consistently produced the oil required by the international system in spite of sanctions imposed on oil-producing countries by consuming countries. Investment for more capacity, however, remains an outstanding question for OPEC countries to grapple with.

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Nuclear Power

David Waller and Alan McDonald ask whether a nuclear renaissance can be predicted

This March, high level representatives of 69 governments, including 25 at the ministerial level, gathered in Paris to consider the future role of nuclear power. Their concluding statement noted, inter alia, that: 'a vast majority of participants affirmed that nuclear power can make a major contribution to meeting energy needs and sustaining the world's development in the 21st century, for a large number of both developed and developing countries'. A 'vast majority' out of 69 is particularly striking given that only 30 countries currently have nuclear power plants, and a few of those, Germany and Sweden, for example, currently have plans to phase them out.

Whether or not the Paris statement signals a renaissance for nuclear power, it at least shows that many people, and governments, have recently taken a critical look at nuclear power – perhaps for the second or third, or fourth, time – and have concluded that it is an option they want to remain available. What are the reasons?

A Good and Lengthening Track Record

Nuclear power is a more reliable workhorse in the global energy system than is commonly realised. It supplies 16 per cent of the world's electricity, a percentage that has remained essentially constant since the early growth spurt halted abruptly in 1986. Thus for the last eighteen years, growth in nuclear electricity generation has kept pace with the steady growth in overall global electricity use. Currently there are 441 nuclear power plants operating worldwide and cumulative operating experience now exceeds 11,500 reactor-years. Asia – the location of 17 of the 25 reactors currently under construction and 20 of the last 30 reactors to be connected to the grid – is the centre of expansion. And, Western Europe will resume nuclear construction later this year when Finland begins building its fifth nuclear plant, marking the first new nuclear construction in Western Europe since 1991.

Nuclear power also has an excellent safety record. There has been but one major accident – at Chernobyl. That accident cost lives and caused misery. But it also brought about major changes. It led to immediate design and operating modifications in Chernobyl-type reactors, but also changes that went far beyond, including, most importantly, the founding of a 'safety culture' of constant improvement, thorough analysis of experience and sharing of best practices. That safety culture now has nearly two decades of impressive statistics demonstrating its effectiveness, and it is that safety record that is a basis for countries considering constructing nuclear power plants.

Growing Energy Needs

All independent analyses and forecasts of global energy needs project large increases in the century ahead – as a result principally of population and economic growth in today's developing countries. Even with population growth now slowing – and demographers at the International Institute for Applied Systems Analysis (IIASA) predict that growth will come to an end in this century – if the world is to meet even a fraction of the economic aspirations of the developing world, energy supplies must increase substantially and consistently.

Countries are presented with varying energy demands and opportunities. However, the best strategy usually involves a mix of energy sources; and, for each country that mix is different. It depends, first, on the indigenous resources available – hydropower in Norway or Austria, coal in the USA, wind on the Danish coast, oil in Saudi Arabia, natural gas in Russia and, in the unfortunate case of some countries, precious little of anything.

Second, the right mix for a given country depends on its energy needs and how fast they are growing. And, as countries develop economically, final energy use generally shifts towards electricity. At the point of use, it is cleaner, more convenient and more flexible.

And, third, a country's energy mix depends on national preferences and priorities as expressed in national policies. How countries trade off among considerations including environmental quality, jobs, occupational hazards, energy security and energy costs is at least partly a matter of national preference, and thus an area of legitimate disagreement – even where there is agreement as to the relevant facts.

But while the situation in every country is different, the entire world is ultimately drawing from the same global resource base, whether it is oil underground or land available for biomass. So while one country may choose differently from its neighbours, they are all affected by each other's choices.

Another reason the participants in the March meeting in Paris want to keep open the nuclear power option is the dramatic fluctuation – largely upward – recently experienced in the prices of oil and gas. There may still be significant oil and gas reserves, but increased prices suggest that no country can count on them being available when needed. Moreover, rising prices indicate the market expects that demand will grow faster than supply, with China being a major factor. It transitioned from an oil exporter to an oil importer in 1993; between 1998 and 2003 it alone accounted for almost 40 per cent of the world's increase in oil consumption; and its oil imports grew by 30 per cent between 2002 and

2003, and they appear to have grown even faster in 2004.

New Environmental Constraints

Russian ratification of the Kyoto Protocol in November 2004 triggered the Protocol's entry into force 90 days later – on 16 February 2005. Its limits on greenhouse gas (GHG) emissions should improve the economic competitiveness of all energy sources with low, or no, GHG emissions. This includes renewables. It also includes nuclear power, for which GHG emissions are only 2–6 grams of carbon per kilowatt-hour for the full fuel chain (including construction of all facilities) – about the same as wind and solar power, and one to two orders of magnitude below gas and coal fired power. In the past, the low GHG emission advantage of nuclear power and renewables was irrelevant to investors, as the virtual absence of restrictions or taxes on GHG emissions meant there was little economic value to their avoidance. That has all changed with the entry into force of the Protocol.

Nonetheless, it is important to distinguish the direct near-term effects on nuclear power of the Protocol's entry into force from the potential longer-term implications. The former are likely to be slight. The latter may well be substantial.

First, the Kyoto Protocol limits GHG emissions only for 2008–2012, known as the first commitment period. And, 2008 is but three years away; very little lead-time for a new nuclear power plant. The emission limits after 2012, which might guide longer-term planning, are still to be negotiated, and initial discussions last December at the 10th Conference of the Parties (CoP) to the UN Framework Convention on Climate Change (UNFCCC) were not encouraging, with neither the large developing countries nor the United States showing much interest. The large developing countries have rapidly growing GHG emissions, but although they are parties to the Protocol, they have no emission limits in the first commitment period. The USA has the highest GHG emissions in the world, but it is not a party to the Protocol and thus also has no binding emission limits.

Over the longer term there are major indirect implications for nuclear power. Kyoto is the first legally binding quantified GHG emission limitation established by the international community. If it succeeds, it will be at least a partial demonstration of the UNFCCC principle that developed countries should take the lead in climate protection. It is an opportunity to test the three 'flexibility mechanisms' and gain experience regarding transaction costs, liability enforcement and dispute resolution. Most importantly, it gives a clear signal that a global carbon emission constraint is emerging that might become increasingly stringent.

> "while the situation in every country is different, the entire world is ultimately drawing from the same global resource base"

All rational actors will hedge against the risk of tighter future CO_2 reduction requirements. This triggers investments in non-carbon technologies, including nuclear. Yet, the impact of these effects on nuclear power will only be felt sometime after the first commitment period.

Security of Supply

In the 1970s, the oil shocks triggered concerns regarding the security of national energy supplies and were major drivers of nuclear expansion in both Japan and France. Similar concerns may prove to be a driving force in the coming decades. The January 2004 Green Paper on Europe's supply security estimated that business-as-usual strategies would increase dependency on imported energy from the then 50 per cent to approximately 70 per cent in 2030. In the electricity sector, where natural gas is the fuel of choice for new plants, and imports from Russia continue to rise, the principal concern is an over-reliance on a single source.

The best strategy to strengthen energy supply security is, of course, to diversify among sources and suppliers. In most countries, nuclear expansion would increase diversity in the electricity sector. And, volatility in nuclear fuel costs is both less likely and of less consequence than potential volatility in, particularly, natural gas prices. Nuclear fuel is provided by a diverse global roster of stable uranium producers, and a long-term supply of fuel requires little storage space. And for nuclear power, fuel costs are a smaller fraction of generation costs than they are for either gas-fired or coal-fired generation.

Aspirations and Expectations

As stated above, current nuclear power expansion is centred in Asia, a continent that is also projected to account for the lion's share of continued nuclear growth in most long-term scenarios. Reinforcing these projections are the explicit expansion plans articulated by China and India, which, between them, account for 37 per cent of the world's population. China plans to expand nuclear capacity by a factor of five to six by 2020; India plans to expand it ten-fold by 2022 and 100-fold by 2052, increasing its share of national electricity from 3 per cent today to 25 per cent at mid-century. A 100-fold increase sounds enormous, but it is equivalent to an average of 9.2 per cent per year, the same as the global average growth for nuclear power from 1970 through today.

And a final reason for rising expectations about the future of nuclear power is based on what the experts are saying. The IAEA publishes two annually updated projections of nuclear power capacity – a low projection, which assumes that no new nuclear power plants are built beyond those under construction or firmly planned today, and a high projection, which assumes additional reasonable planned and proposed projects.

In 2004, the low projection was adjusted upwards for the fourth year in a row, reflecting an increasingly bullish outlook on the part of the utility industry. It now predicts 427 GW(e) of nuclear capacity in 2020, the *equivalent* (new plants, and up-rating and licence extension of existing plants) of 127 more 1000 MW(e) nuclear plants than suggested just four years earlier.

In the high projection there has been less change, and a less consistent pattern of change. Still, the latest high projection shows an 86 per cent increase in nuclear electricity production between 2003 and 2030. The list of reasonable medium-term projects is fairly stable, and each year more of them get promoted from promising prospects to actual projects in the pipeline.

Conclusion

Thus there are good reasons for rising expectations about nuclear power and for the support for it expressed by so many governments in Paris: a good and lengthening track record, increasing energy needs, rising oil and natural gas prices, new environmental constraints, concerns about energy supply security, the nuclear expansion plans of key countries, and the increasingly bullish projections of experts.

So can we predict a nuclear renaissance? Renewables may yet be able to expand at the pace predicted by their strongest advocates, rather than at the more modest rates found in more dispassionate studies. Technological breakthroughs may bring nuclear fusion on line sooner than expected, or allow coal combustion with carbon sequestration and no GHG emissions. Nanotechnology may develop solar cells that can be spread on structures like a coat of paint, or genetic engineering might yield microorganisms that use sunlight directly to split water and produce hydrogen.

More likely, however, the best energy strategies for countries will remain less dramatic. They will vary with national situations, and each will involve a mix of energy sources. In some developing countries, for example, the best promise for rural communities may be that offered by off-grid renewables. For urban situations and the growing mega-cities, on the other hand, large centralised power generation may best match the large centralised demand.

New nuclear power plants are most attractive where energy demand growth is rapid, alternative resources are scarce, energy supply security is a priority or reducing air pollution and GHG emissions is mandated. Nuclear expansion currently remains centred in the Far East and South Asia where these factors are most immediate. But, as reflected in Paris, the ‘area of immediacy’ appears to be broadening. How quickly this happens will depend partly on expectations about market factors, such as the increasing price of natural gas. It will also depend on government policies that encourage long-term thinking, such as those driven by the Kyoto Protocol. And, as always, the prospects for nuclear power will benefit from continuing industry progress in reducing construction costs and improving operating performance.

Judith M. Greenwald discusses keeping the nuclear power option open

Introduction

Addressing the challenge of global climate change will require a sustained and comprehensive commitment to climate-friendly policies and investments throughout the world. Such policies and investments must be focused on enabling a transition to a low-carbon economy through a significant reduction in annual greenhouse gas (GHG) emissions by 2050. A commonly stated goal is to stabilise the atmospheric concentration of carbon dioxide (CO_2) at twice its pre-industrial level – that is 550 parts per million or less. Such a ‘decarbonisation’ in the context of increasing global demand for energy would necessitate an increase of roughly 100 to 300 per cent of present-day worldwide ‘primary power’ consumption from non-CO_2-emitting sources such as renewables, nuclear power, the use of fossil fuels with carbon capture and sequestration, and energy efficiency improvements.

Achieving this transition depends on both near-term and long-term actions. In the near term, it will be necessary to take advantage of current technologies and opportunities, and to make substantial investments in promising technologies for the future. Considering the magnitude of the long-term challenge, differences in the current cost and level of commercial maturity of various low-carbon energy technologies, and variation in the low-carbon resource and technology availability worldwide, it is likely that a portfolio of options will be required, and these investments will need to be sustained for many decades.

Accordingly, it is important to consider any and all low-carbon technology options, including nuclear power, as potential contributors to a low-carbon future. Due to the long-lived nature of capital stock in the energy sector and the effect that early choices have on future GHG emissions, it is important to focus serious policy and investment attention on low-carbon energy sources as soon as possible. Nuclear power provides an example of the urgent need to assess the ability of this technology to play an important role in meeting the long-term climate and energy challenges facing the world.

Opportunities and Barriers

Nuclear power potentially offers a virtual greenhouse gas (GHG)-free source of energy for the electric sector. In addition, nuclear power could enable a future decarbonisation of the transport sector – either through electric vehicles or through the use of electrolytic hydrogen in hydrogen internal combustion or fuel cell vehicles. Despite nuclear power’s potential to contribute to a low-carbon future, its further development is hampered by many problems, and further deployment of nuclear power is essentially 'on hold' in many developed countries – a situation well illustrated in the United States.

Nuclear power currently provides approximately 20 per cent of US electricity supply from 104 operating reactors. Despite its significant role in the US electricity mix, the last new nuclear plant was ordered in 1979, and there are no current plans to build more in the United States. Furthermore, approximately 10 per cent of US nuclear plant licences will expire at the end of 2010 and more than 40 per cent will expire by 2015. Any significant ramp-up of nuclear capacity would probably be a lengthy process, due in large part to the significant time required to license and build a new nuclear plant. Thus, it is likely that the ability of nuclear power to contribute to avoiding significant GHG emissions by 2050 will be determined by whether a major deployment of nuclear power in the United States starts in the next ten to fifteen years.

"approximately 10 per cent of US nuclear plant licences will expire at the end of 2010 and more than 40 per cent will expire by 2015"

Under current conditions, such a near-term deployment seems unlikely, as it depends on the degree to which the nuclear industry can overcome serious barriers, including:

- cost
- technical, political, and social concerns about nuclear waste disposal
- increased proliferation risk, and
- public concern about the continued and expanded use of nuclear power.

Each of these represents a significant barrier alone, and in combination has stymied the US nuclear industry for over the last two decades. Of particular concern to many in the international community right now is the threat of increased proliferation risk caused by continued and expanded production of certain types of nuclear materials.

Grounds for Keeping the Option Open

Despite the obstacles facing an increased deployment of nuclear power, the imperative to decarbonise the future world energy economy to mitigate climate change provides strong motivation to keep the nuclear power option open. This requires stakeholders and policy makers to be frank about the challenges as well as the potential benefits of this technology, and to make the best informed policy and investment decisions with regard to nuclear power in this context in the near term.

In the past, the nuclear debate in the United States has been characterised by two well-entrenched ideological positions. On one side are those who do not consider nuclear power a viable alternative to fossil fuels – mostly on the grounds of safety and waste disposal issues – contending that these problems are insurmountable. The other side argues that nuclear power would be economically and technologically viable if it weren't for misguided public opposition.

As in many other countries, signs are emerging that the nuclear debate in the USA is changing. Some are now asking: 'despite its significant risks and challenges, how can nuclear power be made to work in the context of a carbon-constrained world?' This is mostly due to the recognition that in order to address climate change effectively, all low-GHG emitting options have to be seriously explored. Recognition of the potential value of nuclear power has started to emerge among some of those advocating for near-term action on climate change, and many in the US nuclear industry are touting nuclear power as an option for addressing global warming.

The Path Forward: International Cooperation and Domestic Action

Many questions and challenges remain to be addressed before nuclear power could contribute significantly to climate change mitigation in a way that is acceptable domestically and internationally. Most pressing is the need to minimise the risk of proliferation of weapons-grade nuclear material. Power reactors are not themselves the major proliferation threat; enrichment and reprocessing plants are. Thus one option is to reorient the Nuclear Nonproliferation Treaty (NPT) framework to establish two paths for countries to take: 'reactor only' and 'full fuel cycle'. States with fuel-cycle facilities would be subject to stringent safeguards, but states choosing the reactor-only path could avoid fuel-cycle investments, intrusive safeguards, and nuclear waste challenges.

"Power reactors are not themselves the major proliferation threat; enrichment and reprocessing plants are"

Even if the international community is able to adequately resolve concerns related to international waste disposal and proliferation, cost, domestic waste disposal, safety, and public perception concerns are still likely to hinder the development of nuclear power in many countries. Accordingly, nuclear power is likely to require a near-term policy 'push' in many individual countries in order to be in a position over the long term to contribute to significant GHG reductions.

Recognising both the significant challenges facing the industry, and the potential for nuclear power to play a critical role in enabling a low-carbon future, a study led by a group of MIT and Harvard professors completed a report in 2003 entitled *The Future of Nuclear Power.* Although acknowledging the significant problems associated with this technology, the study group concluded that considering a 'global growth scenario' for nuclear power in the near term was prudent in light of the role that it could play in the challenge of addressing global climate change. Furthermore, the group concluded that enabling such a growth scenario would probably require an explicit near-term policy focus. Listed below are some of the near-term policy options that could address the barriers to nuclear generation and that could increase the likelihood of a large-scale deployment scenario in the United States:

- Electricity production tax credits for a new generation of 'first mover' nuclear plants up to 10 gigawatts electric (Gwe) at a level similar to the US wind production tax credit (currently 1.8 cents/kWh)
- Significant expansion in size and scope of the US DOE's nuclear waste management R&D
- Strengthening and reorientation of the current international safeguards regime in order to meet the non-proliferation challenges of globally expanded nuclear power
- Re-ordering of the priorities of the US DOE nuclear fuel cycle R&D to focus on the 'once-through' fuel cycle, as opposed to fuel reprocessing with its inherent proliferation risks (the once-through mode means removing the spent nuclear fuel for geologic disposal. Closed fuel cycles are those in which the irradiated fuel is chemically processed to separate and recycle in the reactor components that have energy value, principally plutonium)
- Public dialogue and education on the costs and benefits of nuclear power, especially in the context of climate change

Thus, clearly governments – working together internationally, and individually in their own countries – have a key near-term role to play in helping to determine the long-term role of nuclear power in addressing climate change. However, even with the adoption of a comprehensive suite of policies to promote nuclear power, the MIT study group concluded that the role of this technology in the future will ultimately be determined by the willingness and ability of the electric power industry to increase deployment of nuclear plants. Most importantly, governments and industry need to act in the near term to enable an informed decision on whether nuclear power can play a significant role in addressing climate change.

Conclusion

Global climate change presents a daunting challenge for the global community. Yet it can be addressed through a 'decarbonisation' of the global energy economy over the next 50 to 100 years with a portfolio of low-carbon energy and resource technology options. Accordingly, it is important to seriously consider all low-carbon energy options – including nuclear power. If the international community, domestic governments, and the nuclear industry can overcome the significant barriers facing an expansion of nuclear power, it could play an important role in meeting the climate change challenge. Nuclear power can be part of the solution to climate change, but only if it can solve its own problems.

(This article relies heavily on material previously published in the following publications: 'The Future of Nuclear Power' (J Deutch and E Moniz, co-chairs), Pew Center on Global Climate Change and National Commission on Energy Policy Workshop Proceedings – the 10-50 Solution; and E Moniz 'Nuclear Power and Climate Change' – Overview paper in Workshop Proceedings – the 10-50 Solution, Technologies and Policies for a Low-Carbon Future. This article does not necessarily reflect the views of the MIT 'Future of Nuclear Power' study group or the National Commission on Energy Policy.)

Paul Mobbs considers the availability of uranium and the future of nuclear energy

Introduction

The nuclear industry has traditionally argued that nuclear energy is a reliable source of energy in the longer term, but for how long? There are many technical issues, related to the choice of reactor and the operation of the fuel cycle, which affect the longevity of the uranium resource. Potentially these choices could limit the viability of the uranium resource to a few decades.

To decide how valid an option nuclear energy is we must understand the limitations on the availability of uranium, and the current state of reactor technology. There are many uncertainties about how the nuclear industry might develop in the future, but it is possible to conclude that the supply of uranium, at a level that could support large-scale power generation, might only be viable for a matter of decades. Potentially, could a shortage of uranium be the Achilles-heel of the nuclear industry that, so far, the anti-nuclear lobby has missed?

Uranium Resources

Uranium is a resource that is as common as tin or zinc. Some analysts argue that the production processes of the uranium mining industry, and the nuclear industry's use of uranium, mean that we should evaluate the supply of uranium in a similar manner to the evaluation of metal resources. It is the quality, not the quantity, of the resource that we must concentrate upon.

According to the 'Red Book', the OECD Nuclear Energy Agency's statistical study of world uranium resources and demand, in 2002 the world consumed 67,000 tonnes of uranium. Only 36,000 tonnes of this were produced from primary sources.

The balance came from a variety of secondary sources, in particular the ex-military inventory of uranium which is being released as nuclear weapons systems are run down. The availability of cheap uranium from the military has been one of the contributing factors to the shrinkage of capacity within the uranium mining sector over the last decade. It also entails that at some point between 2010 and 2020 the uranium mining industry must dramatically expand to meet future demand.

Estimating the available reserves of uranium is a little difficult as various agencies interpret the availability of uranium resources using different methodologies. If we add together all potential sources, including 'unconventional' sources such as sea water, the amount of uranium that is accessible around the globe is in excess of 17 million tonnes. Most estimates, which consider known reserves and reasonable estimates of other high grade sources of uranium ore, put the figure at around 4 to 5 million tonnes. Some authorities take a more sceptical view. For example the European Commission's 2001Green Paper on Energy discounts speculative sources and quotes only the known uranium resource (2 to 3 million tonnes).

Generally uranium reserves are classified according to the cost of recovery as a dollar value. Clearly this is an imprecise measure given that it does not reflect the net value of the energy produced from uranium less the energy used in its mining and processing and in the generation of power. Below a certain concentration the recovery of uranium will take more energy than it produces. The most productive uranium ores contain 1,000 to 20,000 parts per million of uranium (ppmU). Other potential sources, such as igneous rocks, have concentrations of uranium of around 4ppmU. Sea water, also quoted as a future source of uranium, has an average uranium content of 0.003ppmU. In the 1970s Peter Chapman calculated the cut-off value, at which the energy used to extract uranium from the ore exceeds the energy produced from the nuclear plant, at around 20ppmU. Even with advances in processing and reactor design this is unlikely to fall far below 10ppmU. This puts a limitation on the theoretical size of the uranium resource because a number of the potential sources fall below this level.

Fuel Cycles and Uranium Consumption

The world's nuclear capacity is based upon 'thermal' fission reactors that split uranium atoms and produce heat. The problem with this type of reactor is that it can only split atoms of one isotope of uranium – uranium-235 (235U). As 235U only constitutes around 0.7 per cent of the uranium resource, the amount of energy that nuclear energy systems can generate using current technologies, is very limited.

> "Below a certain concentration the recovery of uranium will take more energy than it produces"

The bulk of the uranium resource, made up of the isotope uranium-238 (238U), does not take part directly in nuclear fission. However some of the 238U is converted to plutonium-239 (239Pu) whilst inside the reactor and this is also fissioned to produce additional energy. The only way it is possible to use the majority of the uranium resource is to adopt a different reactor technology – the 'fast breeder' or 'fast' reactor. This exploits the conversion of 238U into 239Pu by 'fast' neutrons in order to produce 239Pu, and following reprocessing of the nuclear fuel the 239Pu can be substituted for the 235U for future energy production.

The primary difference between the thermal reactor system and the fast breeder reactor system is the way that the nuclear fuel cycle operates. Thermal reactors operate a 'once through' cycle. Nuclear fuel is used to generate energy and then it is put into indefinite storage. Some nuclear fuel is reprocessed in order to recover the plutonium, but at the moment the recycling of plutonium back into the fuel cycle operates at a minimal level – through the production of 'mixed oxide' (or MOX) fuel. Switching to a system where fast reactors are used more widely, in order to operate a more 'closed' cycle, would allow a greater proportion of the uranium resource to be utilised. However, it would also require that the world's nuclear reprocessing capacity was dramatically increased as the closed cycle cannot operate without these reprocessing facilities. The requirement to significantly expand fuel reprocessing, far beyond the world's current capacity, also brings with it unknown factors in relation to the consequential increases in releases of persistent and bio-accumulative radioactivity into the environment.

In 2003, the Massachusetts Institute of Technology produced a detailed study of the future of nuclear power. This provides a wealth of data on the various types of nuclear fuel cycle that might operate in the future, and how much uranium these different fuel cycles consume. On the MIT analysis, the effect of switching from a 'once through' to a 'closed' cycle (where a mixture of thermal and fast reactors is used and the plutonium is recycled through fuel reprocessing) is to nearly halve the consumption of uranium per unit of energy produced. However, despite the fact that using fast reactors would reduce uranium consumption, and allow a greater proportion of the uranium resource to be utilised, no viable commercial design for a fast reactor has yet been produced. The major fast breeder projects have been curtailed by technical flaws principally related to the problems associated with cooling the core of the fast reactor system. This impasse seems unlikely to change in the future given that the new (Generation III) reactor designs currently being tested, and most of the future (Generation IV) reactors that are being designed, are thermal not fast reactors.

The Lifetime of Uranium Resources

The nuclear industry often expresses the contribution of nuclear energy in terms of electricity generation, but it is more realistic to look at its contribution in terms of global energy supply. This is because, as fossil fuels become scarce, nuclear energy would have to displace the energy currently supplied by fossil fuels. Although nuclear energy provides 16 per cent of the world's electricity supply, recent estimates put the contribution to the world's total energy supply at between 6.1 per cent and 6.6 per cent.

> "The actual lifetime of the uranium resource will depend upon the technologies adopted as part of any new nuclear capacity"

At the current level of uranium consumption (67,000 tonnes per year) known uranium resources (2.8 million tonnes of uranium) would last 42 years – a fact highlighted by the European Commission in their Energy Green Paper. The known and estimated resources plus secondary resources (such as the military inventory), a total of around 4.8 million tonnes, would last 72 years. Of course this assumes that nuclear continues to provide just a fraction of the world's energy supply. If capacity were increased six-fold then 72 years would reduce to twelve years. This is because nuclear energy, in terms of global energy supply, must increase by a factor of four to eight to make any significant difference to the use of fossil fuels around the globe.

Consequently, the expected lifetime of the uranium resource would fall by a similar factor. The actual lifetime of the uranium resource will depend upon the technologies adopted as part of any new nuclear capacity. New reactor designs are more thermally efficient (up to 45 to 50 per cent rather than 30 to 35 per cent) which could extend the lifetime of the uranium resource by a factor of 1.7. Introducing a number of fast breeder reactors, to increase the efficiency of uranium consumption, might increase the lifetime of the uranium resource by a factor of 2. Even so, taking these two factors together alongside a six-fold increase in capacity, the lifetime of the known and estimated uranium resource would still be less than fifty years.

This stark problem, if one reads many papers on uranium resources produced by the nuclear industry, is an issue that is recognised but seldom explored. It was highlighted in OECD research six years ago, which noted that if the nuclear option were adopted without a radical change in technology then known uranium supplies would only last 'about a decade'. The recent MIT study briefly acknowledges the matter but, perhaps due to the USA's large indigenous uranium reserves, discards it. Others have acknowledged the short-term problems of capacity in the uranium industry, especially the problems that might arise if mining capacity does not expand before the military inventory is exhausted, but do not look to the longer-term lifetime of the resource. A very few portray a wholly unrealistic scenario, that forecasts hundreds or thousands of years of nuclear energy. This is because they do not take into account the need for the nuclear industry to grow massively in order to displace fossil fuel use, or that a significant part of the globe's entire theoretical supply of uranium may be unusable (because its extraction and use would take more energy than it would provide).

Conclusion

To make a significant contribution to energy supply, nuclear energy would have to expand by such a scale that the lifetime of the uranium resource, along with issues such as the management of radioactive waste and the control of fissile materials, are always going to be problematic. Unlike plant safety or the emission of radioactivity, which can be controlled through better engineering or management, the basic issue of how much energy can be produced from nuclear sources is limited by physical laws and the scale of current global energy demand.

There are clear shortcomings in the current methodology for assessing uranium resources because they are based entirely on the economic costs of production, not the net energy value of the resource once the costs of extraction and use are taken into account. This has important implications, which vary according to the selection of the fuel cycles and reactor technologies used, on the lifetime of the uranium resource. Until the net energy value of the uranium resource, and different fuel cycles, is taken into account we can have no clear understanding of the productive future of the nuclear industry. It is also difficult to assess the environmental implications of the nuclear option as each technology creates varying environmental impacts.

It would be unwise to advocate adopting the nuclear option when we have no realistic idea of how long the uranium resource will last. Clearly the 'once through' cycle has no future – if the world were to adopt this option the world's uranium resources would be exhausted in a few decades. We would very quickly shift from shortages of oil and coal to shortages of uranium. The principle solution to the problem of the 'once through' cycle, adopting a more 'closed' cycle using fast breeder reactors, is itself fraught with dangers. There is no tried and tested fast breeder technology. In addition the scale of the increase in nuclear capacity required to displace fossil fuel is such that the lifetime of the resource would still be a matter of decades, not centuries. For this reason it may be that the longevity of the uranium resource, quite apart from the issues of waste or radioactivity, could be more significant to the future viability of the nuclear industry.

Indian Gas Supply: Elixir for Growth or Priced Out of Reach?

Chris Hansen

Introduction

The continued development of new gas supplies in western India will have a significant impact on electricity markets and new investment in power, fertiliser and other industrial sectors. However, rising international oil and gas prices and the preponderance of gas contracts benchmarked to crude prices have increased prices of imported gas supplies and may scupper demand growth. This article surveys the gas supply situation in the sub-continent and examines the emerging LNG regassification market in western India, and how electricity and industrial companies may respond.

Background

Power and fertiliser sectors currently account for 80 per cent of gas demand in India, 5.7 billion cubic feet (bcf)/day, a total which is projected to grow to more than 0.6 bcf/day by 2010. The total demand for gas in Gujarat alone is approximately 2.3 bcf/day in 2005 and by 2009 demand is projected to increase to 3.2 bcf, a 40 per cent jump. New demand will be driven by sanctioned power plants, (e.g. Torrent and Essar's captive/merchant plants), fertiliser manufacturers and the Gujarat State Petroleum Corporation (GSPC) for resale to retail customers and for state-owned industries.

To meet this demand, India is pursuing supply from the gulf via LNG and several large domestic sources delivered by pipelines. In recent months, state-owned Petronet has commissioned its first LNG regassification terminal in Dahej, Gujarat on the western coast to import 5 (growing to 10) million tonnes/yr and Shell plans to receive its first LNG cargos in June of 2005 at its Hazira facility. (Natural gas is typically measured in cubic feet or m^3 or in energy content, for example million British Thermal Units (MMBTU). LNG is typically quoted in metric tonnes per annum (mtpa). For simplification these units are used throughout. To convert, 1 million tonnes of LNG is equal to 50.9 billion cubic feet (bcf) or 1.44 billion cubic metres (bcm).)

In addition, Reliance and ONGC have announced plans to bring an estimated 14–25 trillion cubic feet (tcf) of new gas finds from the Krishna-Godvari Basin to major consumption centres across the country. At first glance, it would seem that India is now poised for its own version of the 'dash for gas': high demand for electricity, ageing power infrastructure, a new regulatory climate and newly discovered large supplies of natural gas have provided a confluence of forces, which may well make gas the fuel of choice for Indian power and industrial companies.

The future of gas in India in the medium term depends on two main factors. First, whether gas prices will remain low enough to drive reticulation and industry investment vis-à-vis coal and other fuel options; and second, whether an adequate gas pipeline network and regulatory structure for gas transport will be created to send clear, stable investment signals to the market. The two factors will reinforce each other; e.g. high gas demand is likely to provide the political pressure to solve access and regulatory issues, and better regulation/access will increase gas demand.

The most likely fuel competitor is coal, which can provide the lowest cost electricity in some situations, such as a pit-head power station with marginal costs less than Rs1/kWh and levelised cost of Rs1.5/kWh. However, coal supplies are currently constrained by lack of mining capacity and railroad transport bottlenecks. The Indian government has even had to restrict supplies to several coal-fired stations in 2005 due to low production tonnage and is considering cutting all coal allocations for non-power plants to ensure power facilities can operate. Compounding the coal shortage for western India are the added costs of transporting coal from the eastern coal fields. To try to address this problem, Gujarat has announced investment in a 2500 MW lignite pit-head plant as well as a joint venture with Madya Pradesh to build a 2000 MW coal plant that proposes to use nearby captive mines for supply. Both projects are far from financial closure and it remains to be seen whether either state will be able to afford the projects. The other possible solution is to use imported coal at the port to generate power, but with estimated levelised costs of Rs2.25/kWh and plenty of fuel price risk, this may not be viable. In the long term, even with more coal production, Indian rail infrastructure will struggle to move enough coal to keep up with demand and pithead plants will require huge transmission investments to deliver the power to demand centres. Given the poor supply and transport situation, this article will concentrate on gas options.

LNG Supplies and Pricing Variables

In the short term, the two LNG regassification facilities in Gujarat, Shell's Hazira and Petronet's Dahej, are slated to receive as much as 423 bcf (12 bcm) by the end of 2010, compared with 812 bcf (23 bcm) total Indian consumption in 2001. This LNG goal may prove ambitious if prices cannot be reduced and 'guaranteed' for the anchor customers. LNG price of supply contracts have historically been tied to oil price baskets, an arrangement that acts to effectively reduce gas as an alternative power fuel during periods of high oil prices and put the brakes on new CCGT investment. Nervous private power companies and industrial consumers such as Torrent have stated that gas prices over $3.5/MMBTU will make power production unviable. Thus forcing the question: will new gas supplies be priced out of reach for Indian markets?

Reducing price risk may require using a more inclusive basket of fuels to index gas prices, such as adding international coal prices to establish contracts, rather than just oil linked pricing or using longer-term contracts with 'manageable' ceiling tariffs. For example, the recent agreement signed with Iran for LNG has used a two-phased deal to overcome the current high crude prices. For the first three years of the contract (2009–2011), Iran will sell 7.5 million tonnes/annum (mtpa) at a fixed price of $2.97/MMBTU, and then will use a Brent indexed price with a $31/b ceiling and a $10/b floor, or $3.21 and $1.82/MMBTU, respectively. In addition, Iran offered the Indian government a 30 per cent stake in the related liquefaction plants and a 20 per cent stake in the 300,000 b/d Yadravan field plus 30,000 b/d from the Jufier field.

One advantage that India does have in the increasingly global LNG trade is location. LNG transport costs are directly related to distance and India is the closest market for Persian Gulf-sourced LNG. In comparison, the transport costs from Qatar to major regasification sites are estimated in Table 1.

Table 1: LNG Transport Costs from Qatar

Qatar to; Location	*$/MMBTU*
Dabhol, India	0.28
Fukuoka, Japan	0.95
Guangdong, China	0.80
Long Beach, USA	1.71
Everett, USA	1.41
Milford Haven, UK	1.13

Source: *Gas Matters* shipping calculator, 2005

This spread means that India has an arbitrage margin of more than $0.5/MMBTU when compared to its principle demand ‘rivals’ in East Asia. However, the Japanese and Korean markets have historically supported high prices, currently above $5/MMBTU spot price, with their high value-added export industries, which may make this spread too small for India to benefit in an era of tight LNG supply and high crude prices. Currently, the LNG imported by Spain, France, Belgium and Korea is priced around $6.25/MMBTU on a long-term contract. US gas prices are now hovering well above $6/MMBTU and are likely to stay at that level for the short term. However, futures contracts for early 2006 show prices below $5 as expectations of increased supply are factored in. At the $6 level, US LNG terminals look very attractive on a netback basis and could pull supply away from the Indian market as suppliers will not under-price LNG sales when there is a large demand in the world market.

Petronet’s Dahej and Shell’s Hazira LNG projects in Gujarat benefit from the relative proximity, and thus a sizeable transport margin, of LNG liquefaction plants in Oman and Qatar to source ‘cost competitive’ gas. The cost structure for the gulf-sourced LNG includes $0.30/MMBTU for transport and regassification charges, computed by the Indian Tariff Commission using a return on equity of 12 per cent, at $0.54/MMBTU, for a total gas at terminal price of less than $3.50/MMBTU under current supply agreements. The first tranches of the gas have been sold by Petronet for $4.87/MMBTU plant gate in Gujarat, and about 6 cents more in northern India to pay for pipeline costs. The quick sale of this regassed LNG to industry for non-power use demonstrates large pent-up demand for gas and indicates that the market for near $5 gas has some depth. This LNG, priced at nearly double the state subsidised gas price of $2.5/MMBTU bodes well for Shell/Total as they continue to negotiate deals for the new LNG capacity that will be online in June 2005. However, the short-term sales contracts may not be sustainable if LNG prices remain high or if a cheaper alternative is available from new pipeline supply.

Pipeline Supplies of Gas for Western India

The current gas supply is principally from the associated gas found in the Bombay High fields and is distributed through the HBJ pipeline. The state controls the distribution of this gas by offering subsidised rates to power and fertiliser firms. This limited supply of price controlled gas is virtually unavailable to industry and the government is now considering price hikes and full deregulation as it did in the petroleum market.

The most promising new sources of domestic gas supply in India are the discoveries in the Krishna Godvari Basin. Development plans indicate that the production and delivery infrastructure will be available by 2007, but uncertainty over total recoverable gas reserves (estimated at 3–25 tcf) and a number of regulatory and land purchase issues will likely slow the pipeline completion. Reliance has committed Rs150 billion ($3.3 billion) for the two-phase development of its offshore blocks, with an initial production of 40 million m^3/day of gas (1.4 bcf). Water depths in the basin vary from 400 metres to 3000 metres. The project may be held up however by pipeline issues as Reliance is threatening not to develop its holdings in the basin unless state-owned GAIL concedes its current statutory monopoly on inter-state pipeline connections.

On the western side of the country, Cairn Energy has announced gas finds 75 km south of the operator’s giant Mangala oilfield development in Rajasthan. Cairn is now moving to drill an appraisal well to determine the reservoir size. New pipelines would also be needed to bring this gas to market.

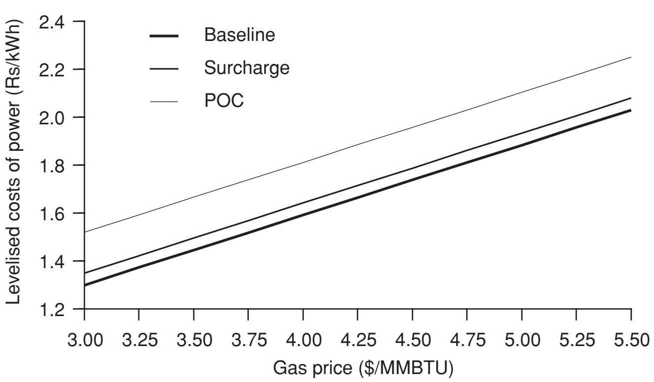
The prospect of international gas imports via pipeline has also been picking up steam. India has signed a long stalled agreement to import gas from Myanmar (Burma) using a $1 billion pipeline across Bangladesh, according to a joint statement from the three governments in January 2005. The agreement is the first international gas pipeline for India and was completed after years of political delays from Bangladesh. The sweetener was a bilateral agreement with India allowing it to increase trade with Bhutan and Nepal. ‘We proposed for a corridor to transport goods to Nepal as well as to import hydroelectricity from Nepal and Bhutan. We have also urged India to narrow the huge trade gap between India and Bangladesh,’ said Bangladesh’s Energy Minister AKM Mosharraf Hossain.

The other main international option is the long touted Iran-Pakistan-India pipeline. The projected 2775-kilometre pipeline would cost $4.16 billion to build at current prices. However, the project faces many hurdles, not least of which the tensions between India and Pakistan. The USA has also entered the fray by increasing pressure against the project under the belief that such a project would aid Iran's economy, turn India and Pakistan into key strategic allies of Iran and reduce US leverage to thwart Tehran's nuclear programme. With the new Iran LNG deal in progress, and growing political hurdles, it is doubtful the pipeline will come to fruition before 2015.

Gas Demand and Price Sensitivity

Regardless of the source of gas supply, the price sensitivity of the Indian power market will be a major factor in gas sales growth. Figure 1 displays the results from a price modelling exercise, assuming a weighted average cost of capital of 17.5 per cent and $600/kW overnight cost for CCGT capacity – this cost is defined as the total resources needed to build a power plant including accounting for capital expenses during the time of construction, land costs, equipment, engineering and commission expenses. The additional lines in the Figure examine the effects of parallel operations charges and additional cross-subsidy surcharges that may be levied by the state on captive and independent power producers.

Figure 1: Gas Price Sensitivity for CCGT in India

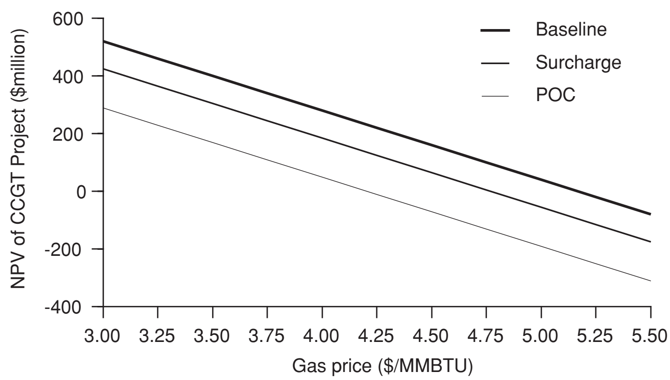


For the baseline case, a competitive levelised cost of power can be generated up to approximately $4.75 for captive use and $4.00 if parallel operations charges are levied. Figure 1 indicates that the high tariffs currently charged by the GEB to industrial consumers, more than Rs4.25/kWh in 2005, can be undercut even at high gas prices. As a result, the gas demand market for power production sold to industry should prove robust even when crude-linked prices are high.

For power plant investors, the other measures to consider are the NPV and the IRR of power projects and Figure 2 displays the results over a range of gas prices.

The baseline case indicates that $3.50/MMBTU gas would yield a NPV of $400,000,000 for a 30-year project, which corresponds to a 10 per cent IRR assuming a Rs2.5/kWh price for the power and neglecting plant size effects. Possibly more threatening than the gas price volatility is the unsettled regulatory issue of parallel operation charges (POC) and surcharges. Looking at the gas price scenario of $4.25, the project NPV dives from more than $200,000,000 in the black to negative value with the addition of the charges. This adds to the argument that gas prices are not the biggest source of uncertainty for power producers, especially if long-term contracts can be used to hedge price and currency risk. Instead, companies face more pressure from the political and regulatory regime to make gas projects profitable.

Figure 2: Net Present Value of CCGT Projects in India



Gas Regulation and Tax Considerations

While the gas regulatory picture is still somewhat cloudy, and the national gas policy still in draft form, there have been positive signals for gas developers. The recent reduction in gas sales tax in Gujarat from 20 to 12 per cent, and the Indian Supreme Court's decision to strike down state regulatory authority over gas have both been reassuring to investors. Going further, the state-owned National Thermal Power Corporation (NTPC) has petitioned the Gujarat government to lower them further to 4 per cent. Competition between states to attract LNG facilities may lead to a tax reduction 'arms race,' which will likely lead rates to fall as a result.

Reports in July 2004 indicated that Gujarat Gas (a BG Group company), India Oil Company (IOC), Reliance (through Gujarat Adani Energy Ltd.), GAIL and GSPC are all pursuing gas transmission and distribution projects. The biggest commitment to date is GSPC's February 2005 announcement of investments totalling more than Rs 50 billion for 2500 km of transmission pipelines in the state. More transmission to serve industrial, CNG transport demand and urban areas is needed, but with a state company dominating the ownership of pipelines, open access may be an issue. The 2003 national gas plan calls for a 25 per cent overcapacity margin for all new pipelines and sets out a goal of achieving open access for all buyers and sellers. With proper implementation, this will reduce the market power of gas transport companies. On the trading side, there are already 25 active players in the market, representing both private and state-owned firms. However, India's track record on opening network industries is mixed at best, with the telecom sector the only notable bright spot.

Conclusions

In summary, the dash for gas faces several major hurdles including high prices leading to demand destruction and regulatory uncertainty. Gas prices over \$4.75/MMBTU will make gas-fired power generation difficult in most scenarios, thus both pipeline gas and LNG suppliers will have to be wary of price elasticity in the Indian power market. Innovative contractual arrangements in which power plant owners bear less of the price risk are needed for the dash to continue. The first adopters are likely to be large-scale CCGTs and industrial plants needing process heat or firms looking to escape high power tariffs from the state electricity boards. Looking beyond gas prices, it is likely to be regulatory and taxation decisions that will have the greatest impact on gas demand, and policy makers will have to be wary not to hobble investment and risk losing a gas-fuelled elixir for economic growth in India.

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Oil Production Expectations outside the Middle East

Andrew Hayman considers West African production growth from 2005 to 2010

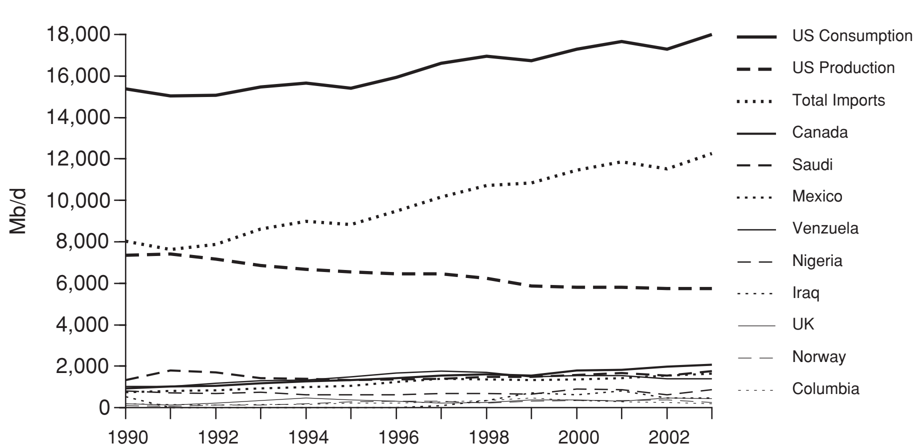
The West African margin continues to attract significant attention from the oil-consuming nations, most notably the United States. In a time of increasing uncertainty of oil supply, particularly from traditional OPEC partners in the Middle East, the USA is looking to supply its ever-hungry economy from partners in West Africa – notably, but not exclusively, Angola and Nigeria. It is no coincidence that President Obasanjo of Nigeria was the first African leader to be received in Washington, in December 2004, after President Bush's re-election to a second term. During his visit, at a forum held by the influential Leon Sullivan Foundation (whose President is ex-US Ambassador to the United Nations, Andrew Young), President Obasanjo said that Nigerian imports would rise from 7 to 15 per cent of US demand. Likewise, President dos Santos of Angola was received in Washington in May 2004.

The US domestic consumption is projected at 20.9 million barrels of oil per day (Mb/d) in 2005, with a 2 per cent per annum growth thereafter. Imports consisted of 12 Mb/d in 2003, or 60 per cent of demand. It is this latter figure, showing the growing dependency of the USA, which is driving oil politics (Figure 1).

The traditional top producers are shown in Figure 1. But with obvious long-term problems in Iraq, tensions with President Chavez of Venezuela, and ongoing ideological differences with Mexico, the USA is looking to secure long-term ties with the African producers. Both Nigeria (currently no. 5) and Angola (no. 7) will move up in the scale of suppliers to the United States.

Major US companies such as ExxonMobil and ChevronTexaco seem to be comfortable working in Angola; industrial projects get done in acceptable time-frames and according to plan. The country is now producing over 1.1 Mb/d (November 2004), and in the last year has successfully put on stream the Exxon-Mobil operated deepwater field Kizomba A (to reach 250,000 b/d in Q1 2005). Girassol-Jasmim, operated by Total, now contributes

Figure 1: US Oil Production, Consumption and Imports



over 240,000 b/d; Xikomba A was put on stream by ExxonMobil in November 2003. Deepwater development operations ongoing at the moment include Kizomba B, BP's Greater Plutonio complex in Block 18, and ChevronTexaco's Belize-Benguela-Lobito-Tomboco compliant tower plan (Block 14). The latter block has been extremely prolific for ChevronTexaco, and significant exploration upside remains.

"the USA is looking to supply its ever-hungry economy from partners in West Africa "

In the pipeline – approved but not started – are Total's Dalia field (240,000 b/d plateau), and tie-back of satellite discoveries in the same area of Block 17 in a follow-up phase of development.

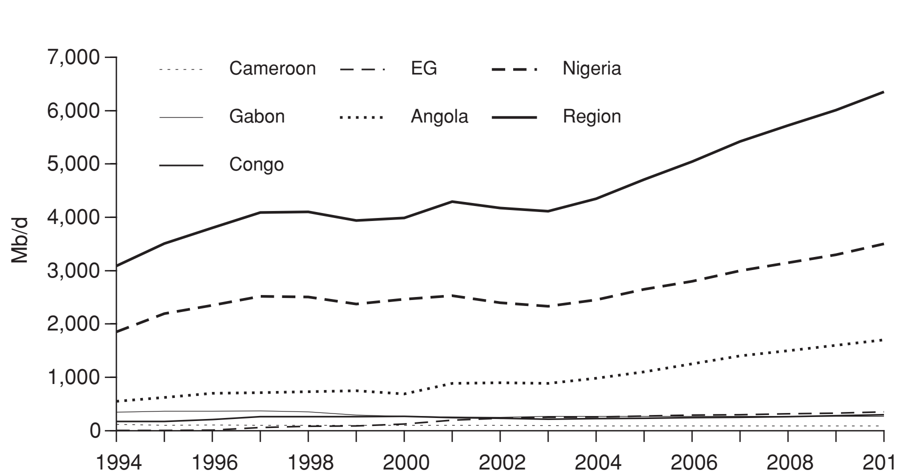
In the ultra-deepwater (Blocks 31, 32, 33), after a difficult start, the operators have successfully cracked sub-salt seismic imaging by using long receiver arrays, and advanced processing techniques including identification of DHIs (direct hydrocarbon indicators), and PSDM (pre-stack depth migration) of copious volumes of 3D seismic data. To date, it seems as though the recoverable oil volumes per discovery are in the range of 100 to 200 million barrels of oil, and clusters will have to be developed together to make commercial viability (? 500 Mb). In 2004, discoveries Gindungo 1 (Block 32), Saturno 1 (Block 31), Plutão 1 (Block 31), Marte 1 (Block 31), Negage 1 (Block 14), Clochas 1 (Block 15), Kakocha 1 (Block 15), Bavuca 1 (Block 15), Tchihumba 1 (Block 15) appear to be exploitable, although none is a giant. Most are Miocene-Pliocene turbidite plays. Sub-sea tie back to planned floating production storage and offtake (FPSO) facilities in shallower-water blocks 15 (Exxon-Mobil), 17 (Total) and 18 (BP) is also a plausible route to exploitation.

An interesting new find by operator ChevronTexaco is the KX-2 (Lianzi) field which is situated in the joint development zone between Angola and Congo. It appears to be commercial. Relations between Brazzaville and Luanda are cordial, and development should not be impeded. In the longer term, the Congo Canyon area is regarded as prospective, though operations will be difficult with the seabed topography.

Nigeria is the other pillar of West African production. Currently national production is around 2.5 Mb/d, of which Shell is the prime producer at over 1.0 million barrels per day. Although traditionally production has been onshore in the swampy Niger Delta, the logistical dangers of working onshore, plus the evident deepwater prospectivity, have motivated the operators to focus more and more offshore – first on the shelf, then into the deep- and ultra-deep waters. But due to internal government bureaucracy, politicking, and complications over gas utilisation, development times to first oil have been, and remain, unacceptably long. Field economics are also seriously degraded by such delays. The Bonga oil field was discovered in 1996 but will not be on stream before late 2005. Plateau production will be 200,000 b/d. The situation at Agbami is similar; a giant field discovered by Texaco in 1998, but which will not be on stream before Q4 2007. It will eventually add 250,000 b/d to Nigerian production. The ubiquitous prospectivity of the deep waters has led to other giant discoveries (Erha, Bosi, Usan-Ukot, Bolia-Chota, Akpo), all of which will be exploited. The key question is – how long will it take to obtain the necessary approvals and finance to move each of these projects forward? The government has often touted its desire to reach the 'Vision 2010' figures of 40 billion barrels of oil recoverable reserves and 4 Mb/d production capacity (from the end 2004 totals of 35.5 Bb and 2.5 Mb/d). Despite the theoretical possibility (given the size of the discoveries), these now seem to us to be unattainable. Perennial problems of adequately funding the government's share of exploration (the so-called cash call) in the traditional onshore and shallow-water permits is also restricting various phases of E and P. In addition, OPEC membership has restricted Nigerian output. We see that 3.5 Mb/d is more plausible by 2010.

Despite stunning successes in the period 2000 to 2003, the first tranche of well results in deep- to ultra-deep waters (in the toe-thrust belt) – ChevronTexaco, Iroko 1; Petrobras, Erinmi 1; Agip, Dou1) – have been disappointing and have put a brake on the rush to ever-deeper waters. Nevertheless, a major programme of exploratory drilling is already firm for 2005. A drillship, the Transocean 'Deepwater Pathfinder', is to drill no

Figure 2: West African Oil Production



less than eleven wells in Nigeria in a rig-sharing contract, over the next fourteen months. Several are Royal Dutch/Shell. Although it is absent from Angola, Shell has many eggs in this Nigerian basket, and OPL 245 and OPL 322 are key to its long-term exploration strategy.

Turning to other countries, Equatorial Guinea is steadily moving up the league table of producers. Zafiro produces 280,000 b/d and is one of ExxonMobil's key West African assets. The Ceiba field – which was put into production in just fourteen months after discovery – will be joined by the Okoume complex (also operated by Amerada Hess) which will contribute 50,000 barrels per day. Hess is investing almost $1 billion. The government oil company GEPetrol has predicted that, unconstrained by OPEC quotas, national production will increase to 350,000 b/d, when it will be capped. On the exploratory side, there have been few heavyweight discoveries outside the Northern Block G area in 2004. However, Marathon has added over 160 million barrels of oil equivalent to its reserves (gas + condensate) in the Alba area through appraisal drilling.

> "In the ultra-deepwater … the operators have successfully cracked sub-salt seismic imaging"

Other countries in West Africa which may contribute to regional oil production by 2010 are Côte d'Ivoire and Ghana. Côte d'Ivoire has one deepwater field (Baobab) currently under development by Canadian independent CNR International (200 million barrels of oil recoverable; 70,000 b/d plateau production). A further Albian fault-block prospect, drilled in January 2005 as Zaizou 1, was unsuccessful. In the west of the Ivorian offshore, Houston-based US independent Vanco Energy has recently assembled a group of Chinese and Indian companies (in expansionary mood overall in Africa) as co-venturers to drill the San Pedro prospect in March this year. If the well is successful, we would expect a rapid development using an early-production leased FPSO. So far, the civil disturbances in Côte d'Ivoire have not affected the offshore operations, and in any case, contingency plans are in place to operate offshore assets from neighbouring Ghana.

Further east on the transverse margin, through Ghana-Benin-Togo, exploratory drilling has not been markedly successful through 2003 and 2004. Expensive deepwater wells have been drilled by Kerr McGee (2 in Benin, both with minor oil), Devon (Ghana) and most recently Hunt Oil (2 in Togo). But the perception will rapidly change with a good success in the vicinity – for example by Vanco. Other acreage – in the Cape Three Points area of Ghana – is in the initial stages of exploration by Vanco Energy, and newcomer Kosmos Energy, which has committed to undertake 3D seismic in Q1 of this year.

Other sub-Saharan African countries striving for deep-water oil discoveries in 2005 include South Africa, where in the Orange Basin, BHP-Billiton and Forest Oil/PetroSA should drill this year. The first well for the Nigeria-São Tome Joint Development Zone Block 1 may be drilled at the end of this year by ChevronTexaco. Prospect sizes are likely to be upwards of 250 Mb, to judge by the nearby Akpo success. But the proof of the pudding will be in the drillbit.

As Figure 2 shows, we see the West African region contributing up to 6.4 Mb/d to world production by 2010 – with the lion's share at 1.7 Mb/d and 3.5 Mb/d to Angola and Nigeria respectively. However, post-2010, there will still be a lot of fuel left in the tank.

Ivan Sandrea analyses South American (Non OPEC) medium-term production outlook

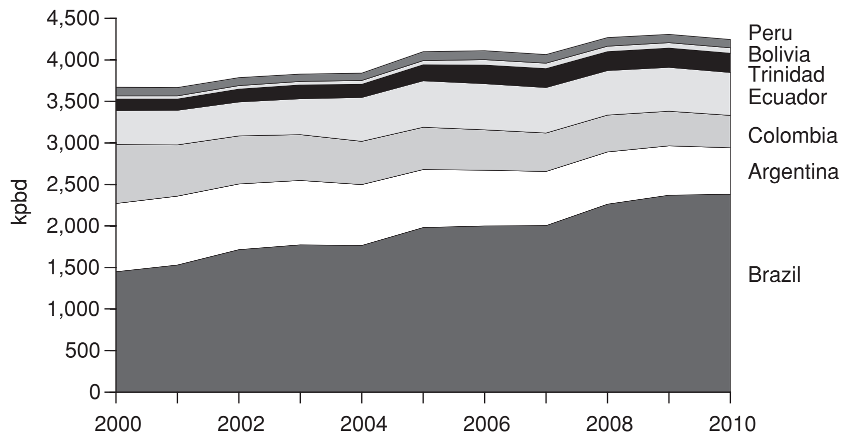
During the1960s, oil production in South America (i.e. Argentina, Bolivia, Brazil, Colombia, Ecuador, Peru, and Trinidad) rose gradually to average 2 per cent of World oil supply or 1 million barrels per day (Mb/d). Oil production then continued to rise slowly due to limited access to prospective areas and technological constraints, except in 1973 when production increased sharply to 1.25 Mb/d (Ecuador began pumping from the Shushufindi field). In 1979, oil production reached 1.4 Mb/d and the largest producers were Argentina, Ecuador, Peru, and Trinidad (i.e. 80 per cent of total production from South America ex Venezuela). Oil production in Brazil remained flat through the 1970s, and in Colombia it declined by half.

However, the next twenty years from 1980 to 2000 saw profound changes in technology, and in the fiscal and industry structure in most South American countries, particularly in the 1990s. This led to increased exploration, the discovery of several giant fields and the start-up of new projects from the Andean foothills to Brazil deepwater. Oil production increased to 3.4 Mb/d in 2000 from 1.4 Mb/d in 1980 and South America's share of World oil production doubled to 4.6 per cent from 2.3 per cent. Proven reserves also increased to 18 billion from 7 bn barrels. By 2000 virtually all South American countries allowed foreign participation in E&P except Brazil, where the oil industry remained nationalised until 1997. Despite the fact that Brazil was the last to open its industry, the discovery of the Campos basin, combined with the successful development of cost effective technologies by Petrobras, made Brazil the engine, but not the only country, driving production growth in the region. Of the 2 Mb/d net volume growth between 1980 and 2000, Brazil accounted for 1.2 Mb/d, Colombia 580 thousand barrels per day (kb/d), Argentina 313 kb/d, and Ecuador 203 kb/d. On the other hand, production declined in Peru which saw its peak production in 1983, as did Trinidad in 1978.

In terms of exports, all countries except Bolivia, Brazil, and Peru were net exporters by 2000. The relatively superior quality of South American crude and its proximity to the US market made the region an important supplier to the United States – in 2000 South America (ex Venezuela) accounted for 6 per cent of US imports or 500 kb/d. Outside of the USA, oil exports remained limited to other countries in the region as well as Central America and the Caribbean due to low spare export capacity and lack of suitable markets beyond.

From 2000 to 2004, oil production in South America rose further to 3.87 Mb/d (4.7 per cent of World oil supply), due to contributions from deepwater projects in Brazil, together with expansions in Ecuador and Trinidad (Table 1). However, larger than expected field declines in Colombia and Argentina, and the accident in Brazil (P36), slowed the growth trend of the region. Total proven reserves also increased in all countries, except in Colombia, to reach 21 bn barrels in 2004. In terms of exports, Ecuador increased its supplies to the USA to 228 kb/d in 2004 from 128 kb/d in 2000 after the OCP pipeline began operating. But exports from Argentina and Colombia to the USA declined by 200 thousand barrels per day.

Figure 1: South American Production Outlook



Outlook for the Region

Looking ahead, in the period between 2005 and 2010 oil production in South America (excluding Venezuela) is forecast to expand to 4.3 Mb/d by 2010. Brazil, however, is expected to be the only source of growth where it is anticipated that oil production will reach 2.3 Mb/d in 2009/2010. At least twelve deepwater projects are scheduled to start bringing 1.3 Mb/d of new volume excluding field declines. Production is forecast to remain broadly flat in Trinidad, Ecuador, Bolivia, and Peru as field declines are expected to be offset by new projects (most of which are small) and expansions in gas fields that contain liquids (i.e. Camisea field in Peru, Margarita field in Bolivia). In Argentina and Colombia, production is forecast to continue to decline at around 4 per cent p.a. accelerating to >6 per cent p.a. towards the end of the decade. Some positive surprises from Trinidad and Ecuador should not be ruled out, although, in terms of volume, any positive surprises are unlikely to represent more than a maximum of 2 per cent of South American oil production in any given year.

In terms of exports, future trends do not look much different from those in the 2000–2004 period although Ecuador's export growth is likely to be limited. In Brazil, domestic demand growth is forecast to broadly match domestic supply plus net trade growth until 2007/08. Post 2008, Brazil is expected to become a net crude exporter but the volume is unlikely to be material, unless domestic market demand growth is less than predicted.

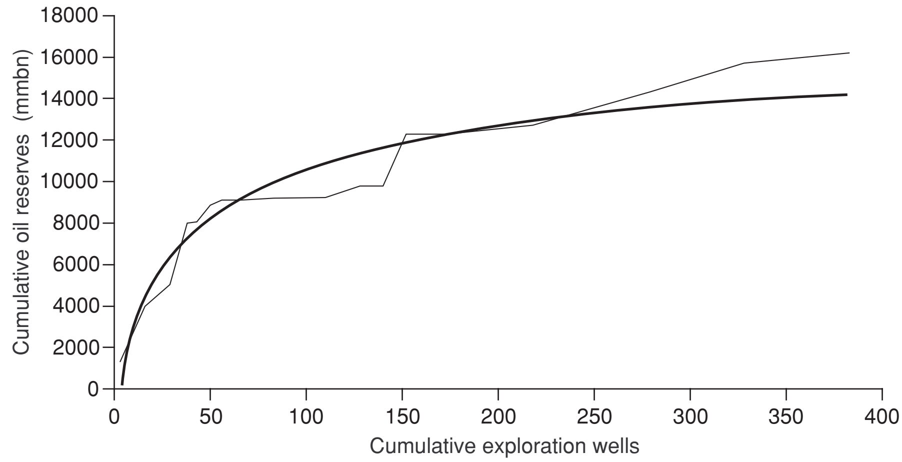
Table 1: South American Oil Production by Country (kb/d)

	1980	*1990*	*2000*	*2004*	*% of production available for exports (2004)*	*Peak Year*	*2003 Reserves (bn bo)*
Brazil	188	650	1,451	1,770	0 per cent	not yet	10.6
Argentina	506	517	819	730	51 per cent	1998	3.2
Colombia	131	446	711	522	33 per cent	1999	1.5
Ecuador	206	292	409	530	40 per cent	2005	4.6
Trinidad	212	150	138	157	30 per cent	1978	1.9
Bolivia	33	34	38	46	0 per cent	not yet	0.2
Peru	196	130	104	89	0 per cent	1983	1.0
Sum	1,472	2,219	3,670	3,844			23.0
Per cent World	2.3	3.4	4.9	4.7			

Uncertainties

The ability of the industry in South America, except in Brazil, to maintain oil production and deliver growth can be described, compared to other regions of the world, as highly uncertain and technically challenging. This assessment is supported by increasing decline rates in key fields – in some of which the causes remain unexplained – the small size and low number of new projects, the low average size of recent discoveries, and the relatively more attractive opportunities outside the region from a technical and political point of view. The last point is particularly important given that strategic and financial commitments towards the region, particularly in Argentina, Bolivia and Colombia, appear to be short-term rather than long-term, and at best, gas oriented. In addition, the absolute level of exploratory activity in the region (including Brazil) has declined in spite of $40 oil. For instance, although in Colombia fiscal changes have been introduced in order to attract investment in exploration, the industry has yet to respond. New areas offshore Colombia in the Pacific (deepwater) will also be offered soon, although these are unlikely to draw material interest given geological constraints. Argentina's economic challenges have created uncertainty in the entire energy sector and this has resulted in investment plans being delayed and changes in the strategy of some producers. In Trinidad and Bolivia, the successes of the last few years have resulted in greater policy and industry focus on gas projects. Last but not least, there seems to be some renewed interest in Ecuador and Peru, but activity remains limited due to complex geology and access.

Figure 2: Brazil Cumulative Exploration Wells vs Cumulative Reserves



Brazil: Challenges and Projects

In contrast to the rest of South America, Brazil has an extensive programme of projects, but expected production growth is subject to additional and particular challenges; on the one hand a tight delivery schedule for twelve complex deepwater projects and, on the other, accelerating decline rates in giant deepwater fields producing heavy crude, such as Marlim and Albacora. There is also a heavy ongoing investment requirement for these projects which could be subject to oil price volatility or domestic policies.

Recent experience shows that the average delay from the original start-up date to the completion date of major deepwater projects in Brazil has been around ten months. For instance, construction delays pushed back the start-up date of Barracuda and Caratinga by almost a year. Over the next four years, at least twelve green and brown field deepwater projects are expected to come on stream. Barracuda and Caratinga are already producing, with a combined output of 300 kb/d at peak (see Table 2). Two more projects are scheduled to start later in 2005, Jubarte Phase I and Albacora Leste, with a combined output of 240 kb/d at peak to be reached in 2006. No major green field projects are scheduled for 2006, but Albacora Leste could slip to late early 2006 due to bidding and construction delays. In the 2007 to 2008 period five more projects are scheduled to start, including the giant Roncador field. But, the programme for the Roncador field as well as the expansion of several new fields in the Campos basin is also dependent on the execution of the recently sanctioned PDET project, forecast to start commercial operations in December 2006. The PDET project will allow tankers to load oil from a group of platforms for transportation to coastal terminals or directly for export to other countries.

Table 2: Key Deepwater Projects in Brazil

Project	*Start Year*	*Period*	*Operator*	*Volume at peak*
Albacora Leste	2005	3Q	Petrobras	180
Barracuda	2005	1Q	Petrobras	150
Caratinga	2005	1Q	Petrobras	150
Jubarte Phase I	2005	2Q	Petrobras	60
PDET (facilities)	2006	4Q	Petrobras	
Marlim Leste	2007	2Q	Petrobras	140
Roncador P 52	2007	1Q	Petrobras	180
Roncador P 54	2007	4Q	Petrobras	180
Frade	2007		CHX	110
Marlim Sul P 51	2008	1H	Petrobras	180

Considering that the giant Marlim and Albacora fields (among others) which account for 30 per cent of Brazil's total output are already in decline, any material delays in the start-up of new projects, will impact Brazil's output growth rate and consequently the growth rate of the entire South American region. The decline rate of deepwater fields post peak tends to be higher than in offshore/onshore fields and Brazil's deepwater fields are no exception. In fact, the difficulties are greater in Brazil compared to other deepwater provinces given the water depths, reservoir depth and crude properties. There is no doubt that Petrobras has a fine technological track record, but the physics of deepwater fields once they begin to decline remains highly uncertain, as already seen in the Gulf of Mexico (i.e. Mensa, Brutus, and so on).

It is also necessary to point out that Brazil has been experiencing a lack of exploration success in searching for commercial oil deepwater (and onshore), and, if this trend continues, deepwater oil production growth could be constrained post 2010. International companies have been disappointed with exploration results across the country and this has led to an overall decrease in the level of exploratory activity despite the level of oil prices of the last five years. Recent discoveries have tended to be relatively small, low API, away from infrastructure (i.e. Espirito Santo basin) and not necessarily in shallow water. By the end of 2003, a total of 383 exploration wells had been drilled in deep water resulting in 34 discoveries (9 per cent success rate). However, discoveries peaked in 1987 and 82 per cent of the reserves discovered have been concentrated in the Campos basin. As a result, Brazil's deepwater creaming curve, which in theory shows the maturity of the region, already displays a profile comparable to that of a mature region such as the North Sea (Figure 2).

On present evidence, there is little doubt that the next leg of production growth in South America not only rests on one single Country and a single Company undertaking some of the most complex projects in the industry, but also rests on the ability of the industry to manage field declines effectively and discover new reserves in other South American countries in a highly challenging and uncertain environment. Beyond 2010, if the medium-term forecast turns out to be accurate, South America is likely to reach a plateau shortly after the end of this decade, accompanied by a peak in production in Brazil. Other areas of South America are unlikely to come to the rescue. Chile is a small oil producer (12 kb/d) and has no real prospects. And, although new frontier exploration activities are being undertaken offshore Guyana and Suriname, it will be some time before we learn about the commercial prospectivity, if any, of these two countries.

Russian Oil Supply: Performance and Prospects by John D. Grace

A New Book from Oxford Institute for Energy Studies, price £45

As the world confronts a new phase in the oil market with prices not experienced since the early eighties, we face an odd asymmetry. Demand growth is certain over the long term, but uncertain in the short term, especially given its preponderance in China. But the inverse is the case for supply: certain in the short term, less so for the long term. The most important non-OPEC exporter by far is Russia. Understanding Russia and its potential to help meet the growth in world oil demand is a key to postulating the future of the world oil market. In a new book soon to be published, Dr John Grace provides a timely and essential analysis for discussing the role Russian oil might play.

Russia's oil resources are not in question. Its conventional oil reserves are the largest of any non-OPEC country. Since the world oil industry began in the 1860s, Russia has produced more oil than any other country, after the USA. During the Soviet era its production rivalled those of the USA and Saudi Arabia. In 1987 Russia was the largest producer in the world. Nine years later in the chaotic wake of the Soviet collapse, production had sunk to nearly half. Since then Russia's production has steadily increased; by 2004 it again approximated Saudi Arabia's.

What is behind this recovery? Can Russia continue to expand and exceed its mid-eighties levels? And more important, will it and should it? This book provides the framework regarding Russia's oil endowment needed before one can consider answers to these and other questions. John Grace reminds us of how central oil has been to the modern economic history of Russia, beginning in Baku in the late nineteenth century. Oil has been the engine pulling the country's material production. But like any engine, its future performance depends on its past maintenance and in many ways oil reservoirs are no different. The author provides valuable insights into how geological caprice bestowed on Russia its hydrocarbon riches and how Russia exploited and abused that endowment.

The legacy of the Soviet era management and petroleum production practices is imprinted on today's Russian oil industry and in particular its structure. Understanding this aspect helps us comprehend the ranking and geographic focus of the Russian companies that are quickly becoming household names, which fields constitute their core assets, what their upside might be, and where they might sit as a potential target for renationalisation or merger. The concentration and size distribution of the companies is reflected in the size of the fields under production and development, mirroring to a certain extent a worrisome structural phenomenon among the international oil companies after their mergers and acquisitions during the nineties. Very large oil companies are not sustained by small oil fields. We also begin to understand why Yukos's return to state ownership might be about more than reprimanding its principal owner for interfering in politics.

Even a passing knowledge of post-Second World War Russian history shows how this background of the Russian oil industry, its endowment and management figured in the command economy. We also might appreciate why, during the Yeltsin interregnum, oil was the target of perhaps the most egregious appropriation of a nation's resources by private agents in history; and then understand the recent methodical and heavy-handed restoration of those resources to state ownership.

How the Russian leadership uses oil and gas to gain political legitimacy and leverage will be a force to understand and watch carefully. Just as Lenin saw electrification of Russia and Soviet control as defining communism, perhaps Putin sees oil and gas as defining post-communist Russia. Subsidised domestic energy prices and hydrocarbon exports underpin the current Russian economy. While this dependence alone might qualify Russia for membership in OPEC, more relevant is whether Russia and OPEC have competing or convergent interests in the oil market. This book provides the basis for beginning to understand what position Russia might take should oil prices ever decline to levels that begin to seriously erode Russia's revenues from oil.

Personal Commentary

Walid Khadduri

Most analyses of oil supply and demand include a statement about the geopolitics of the Middle East and the possibility of supply disruption from the region. There is, therefore, an assumed political premium to the oil price.

While it is true that the Middle East has been in a constant state of trouble and mayhem as far back as one can remember, and events since September 11 indicate that we are in for major confrontations and changes in the long haul, the fact of the matter is that the actual impact on the security of supply has been minimal. One can even venture to say that the conscious commitment to deliver the oil to world markets is stronger now than it has ever been.

The Middle East has been stigmatised by the 1973 Arab oil boycott. This characterisation still finds itself in the energy literature of the day as a route the Arabs might possibly take against the West.

What this argument neglects is the politics of the Middle East today, with the US navy and bases all over the region, the disparate politics of the Arab world which allows for virtually no common policy (positive or negative), and the emerging intricate trade relations between the Arab countries, the United States and Europe that necessitate free trade and open markets rather than boycotts.

When Saddam Hussain stopped oil exports in April 2002 in support of the Palestinian Intifada, he did not find any support among the Arab countries. Even Iran, which had originally called for the boycott, did not extend support to Baghdad.

What has emerged in the past few years is OPEC taking the initiative, without much fanfare, in assuming the role of the First Line of Defence in support of market stability. This policy has evolved both as a result of the new world politics and the self-interest of the major producing states.

A clear demonstration of this policy can be traced to December 2002, with the successive disruptions to the Venezuelan production and the consequent stoppage of the short-haul exports to the US market, the ethnic and tribal conflict in Nigeria and the invasion of Iraq. These events (on and off), shut down between 2 and 3 million b/d of crude oil. However, OPEC member states substituted the difference, and there were no supply shortages in world markets.

What is ironic is that, while the Gulf States provided the necessary crude to substitute for the shortfall, the neo-conservatives in the United States launched a vocal propaganda campaign showing how Russia and Iraq would replace the Gulf in general and Saudi Arabia in particular, as the main suppliers of crude to world markets. The impression given from within the Beltway during 2003 was that the world balance of oil power was about to change, or even had already changed, with the invasion of Iraq.

Now that OPEC states, other than Saudi Arabia, are producing at capacity, there is little blame being attached to them for the current high prices. The issue now is sustained rising demand instead of producers reducing supplies to raise prices.

Nevertheless, two subjects continue to be raised in the current discussions about OPEC.

The first is that OPEC states are producing at high rates because they need the money, and their public budgets demand the extra revenue.

While it is true that the economics, and politics, of the Middle East leave much to be desired, and many reforms are necessary to straighten matters out, it is clear that the present state of high oil prices is demand-driven and not the evil work of the producers.

The second is the increasing reference these days to market fears about lack of appropriate spare capacity and that the 1.5 to 2.0 mb/d put aside by Saudi Arabia is not sufficient. There are legitimate grounds for this fear, especially now that world oil consumption is around 82 million barrels per day. However, blame should be distributed evenly among all those concerned.

There is a lack of timely, comprehensive and transparent information on supply and demand. The monthly secondary source figures leave much to be desired. Meanwhile, the scores of analysts and research institutions have failed to predict the rise of demand in China and the rest of Asia. The fact that we have all been surprised since 1Q and 2Q 2004 about the surge in demand, instead of the predicted shortfall, does not speak well for all the research and monitoring tools that have been developed during these past years.

Finally, there are two gaps in the discussions about capacity. One does not need much reminding that the preferred policy of the White House and Congress in the past two decades has been to impose sanctions, particularly oil boycotts, against rogue states which happen to be mainly oil-producing countries.

Whatever the political merits of the case, and this is not the place to discuss this issue, the fact of the matter is that the boycott of Iraq, Iran and Libya over some two decades has thwarted the oil development of these countries whose production capacity is around 8 million barrels per day. This sanctions policy is still very much with us today. The United States has just advised against the Iran-Pakistan-India gas pipeline, as well as issuing daily threats to impose sanctions against Syria and Sudan. There is a price to pay for all the disruption to capacity expansion in these countries, and the consumer is paying that price.

The other capacity issue concerns the producing countries themselves. If the North Sea has proven reserves of approximately 16 billion barrels and produces around 5.5–6 mb/d, why cannot the OPEC countries with their tens and hundreds of billions of proven reserves provide more capacity? Is the issue geopolitical, or economic? There is no clear and satisfying answer to this question.

Asinus Muses

Like Old Times

Asinus was temporarily jolted back to earlier decades of his life when he read the other day that Oman had signed an agreement with PDO to extend its concession until 2044. And it would be even more like old times if Libya, as is reported, might be thinking of offering new ones. Even if a twenty-first century concession isn't quite the same as a twentieth century one, it will nevertheless be a concession.

As Corny as Kansas…

Asinus is finding it increasingly difficult to keep pace with alterative energy sources. He is accustomed to – perhaps saturated with – sun, wind and tides, but it is the subdivisions of biomass that are now creating something of a fantasy world. Recently he has noted the following power station fuels: tallow, sawdust, sewage sludge, dung, chicken waste, palm nut kernels, olive cake, woodchips, willow and rapeseed. A worthy collection, it might be said, although tallow and sewage pellets are apparently about to be reclassified as waste by the EU and will no longer qualify as renewables. Never mind, what is somebody's energy loss will be someone else's wasteful gain.

Expert Witness

Calculating oil reserves is becoming increasingly complicated. You must first be able to describe the difference between the UNFC proposals and the definitions used by SPE/WRC and SEC; you must then be able to compare and contrast the advantages, for instance, of categories 111,112,113 over 1P, 2P and 3P. Having mastered that, you may be able to qualify as a lobbyist for whatever system you think is the most logical, desirable or favourable to the world at large and/or your own interests. As far as can be seen, however, the actual oil reserves will remain unchanged in spite of your new expertise.

Traffic Jams

General Motors has predicted that by 2020, which is getting quite close now, there will be over 1 billion vehicles on the world's roads. What hasn't been predicted is how many more miles of roads there will be, nor where they might be going to or coming from.

Kyoto Police

With the ratification of Kyoto by Russia we are assured that this legally binding Treaty must now achieve its objectives. It is, however, unclear to Asinus who will do the policing and what sanctions can be imposed by whom on any treaty transgressors. He imagines, however, that this is something that can be sorted out to the advantage of politically influential defendants in due course.

Unconventional Responsibility

Asinus reads that Shell 'will become a world leader in the responsible production of unconventional oil'. Can we be sure that this isn't a misprint for 'unconventional production of responsible oil'?

Fakir Emplacement

Will those who used to lie on beds of nails now be tempted to try their luck on pebble beds?

Creative Litigation

It seems that the EU has decided that, if you can't beat OPEC, you should join it. Asinus reads (or was it an April fool?) that OPEC and EU will meet together in June to discuss ways of stabilising oil prices. He can't be the only person wondering if there's a possibility of class action litigation ahead.

In the Rough

With oil prices around $50 the scope for speculative investment seems as compelling as it was to those tulip bulb investors a few centuries ago or to the dot.com merchants a decade ago. In Canada they apparently call this type of hopeful acreage 'moose pasture', although, if the moose actually exist, they probably constitute more of an asset than whatever is contained in some of the dubious seismic evidence on offer.

Elemental Responsibility

When he was younger Asinus remembers that, whenever there was a drought, a heat wave, prolonged frost or what seemed like a month of rain, this was simply attributable to 'the weather'. Nowadays we only need a couple of days of what is perceived to be abnormal heat, cold, rain or wind to have it blamed on 'global warming'. Holding the weather responsible is obviously insufficiently rational for the twenty-first century.

An OPEC Bonus

Asinus recently saw the following essay question in an examination paper. 'If bonus and stock options for oil company executives depend on the company's results and its results are greatly influenced by the level of oil price, to what extent are oil company executives reliant on OPEC for their bonuses and stock options?' Discuss.

Nightmare

Asinus dreamed the other night that, while he was Saving Oil in a Hurry, as suggested by the IEA, he fell over an oil Superspike erected by Goldman Sachs. He then woke up.

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