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The world's growing demand for energy and a desire to diversify sources of energy has driven demand for natural gas. This issue of *Forum* looks closely at recent regional demand and supply developments: the greater flexibility of natural gas trade following the rapid growth in LNG trade over the past 20 years, allowing the emergence of major consumer markets in East- and South-East Asia; the development of hubs for spot trade in North America and Europe, allowing for a rethink of the traditional price link of contracted gas to oil or other energy prices in this part of the world; and recent technology breakthroughs in the area of unconventional gas, which may yet redefine the import and export market, most immediately the USA.

We start with an account of Europe's ongoing transition from a traditional market with oil-linked long-term contracts to one with shorter contract lengths with a much greater role for hub-based pricing. Thierry Bros argues that the rationale for the use of oil indexation in Europe has disappeared, making a greater share of gas-to-gas links in contract formulas more sensible. The biggest remaining challenge in his view consists in the European gas market's continued dependence on its main long-term gas supply partners. For this reason, Bros suggests Europe needs its own shale gas revolution similar to that in North America to ramp up production and supply options.

Given the concentration of gas suppliers to traditional import markets such as Europe, Laura El-Katiri reflects on the viability of what some market observers see as a potential gas-cartel in making, the Gas Exporting Countries' Forum. In her view, recent responses to the forum have been vastly over-exaggerated, for the continued predominance of oil-linked, long-term contracts limits exporters' ability to impose quotas and to reduce production, and the lack of liquid spot markets in most regions looks likely to prevent any change in prevailing contracting practices. This is because 'the reality is that gas markets, and the pricing of gas, until today function very differently from oil markets, and for a variety of good reasons.'

Howard Rogers turns to North America, where the spectacular breakthrough in US shale gas production during the late 2000s has fundamentally turned around the region's natural gas balance outlook. Rogers nevertheless cautions expectations about US gas exports, pointing towards declining Henry Hub spot prices and the big question of the commercial viability of much of the

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Natural Gas Demand and Supply

THE OXFORD INSTITUTE FOR ENERGY STUDIES

US shale gas industry in the coming decade. In Rogers' view, only sustained, sufficient Henry Hub price levels, and a positive long-term response by industry will maintain the present US outlook.

Australia looks set to overtake Qatar as the largest supplier of LNG before 2020 and David Ledesma believes that it can be expected to maintain this position beyond the next decade. The key challenge for Australia's LNG potential, he argues, is that 'over the past five years, the cost-base of LNG projects has increased, reflecting rising contractor and raw material costs. As a result, the Australian projects that are currently under construction are the most expensive LNG projects in the world.'

Russia, the world's largest gas producer and key supplier of Europe's market, is expected to maintain this role. Simon Pirani argues that nevertheless 'the way that Russia produces and markets natural gas will change substantially over the next decade.' This is due to changing market conditions both at home and in its main export market, including the geographical shift in production away from former key productive centres towards more frontier projects; a change in the industry's corporate make-up; new market conditions for the sale and marketing of gas under the planned domestic market liberalisation framework; and a further decline in Russia's share of the European market coupled to its increasing interest in Asian markets.

Turning towards main regional demand centres, Keun-Wook Paik analyses China's options as a natural gas consumer, and emphasises the country's growing need for imports – most importantly via LNG. Anil Jain looks at the Indian domestic market for natural gas, which is yet to evolve to match the country's significance as a demand centre on the global oil market. Looking more closely at regional trade options, Danila Bochkarev argues the case for the Trans-Afghan Corridor to supply both India and Pakistan with much needed natural gas. The project, first proposed in the 2000s, would involve not only a new regionally significant role for Afghanistan as a transit country, but would contribute to the creation of a new cross-regional sub-market between Central Asia and the Indian Sub-Continent.

Africa and the Middle East present a varied picture. Jon Marks argues that Sub-Saharan Africa, so far mainly viewed as a sub-regional net importer, may set out to become a producer, and possibly even exporter following East Africa's recent, significant discoveries of commercial quantities of natural gas. Hakim Darbouche suggests that the Middle East and North Africa's natural gas potential on the other hand remains under-exploited 'owing to a combination of low domestic gas prices, unattractive fiscal terms, and heavily-bureaucratised sector management.' In view of the region's own rapid demand growth, he sees the MENA likely to evolve as a growing demand and import market, rather than a major supply centre of natural gas. Walid Khadduri looks at the most recent offshore discoveries in the East Mediterranean, Israel, Cyprus, and the wider Levant basin. Rather than development potential, in his view it will be politics that are likely to determine the region's outlook as a future natural gas producer – and exporter – to the regional market and possibly Europe.

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European Gas Supply: On the Verge of Being Mostly Spot-Indexed

THIERRY BROS believes that Europe needs a shale gas revolution to achieve a fully functioning European gas market

According to our estimates, in 2011, 58 percent of the gas sold in Europe was under an oil-linked formula (Figure 1). Since the 2008 crisis, this ratio has remained unchanged at 58 percent: on the one hand successful renegotiations of long-term contracts introduced some spot indexation but on the other, due to demand destruction, buyers had to reduce their spot purchases and there was an increase in oil-linked Qatar LNG volumes in Continental Europe during this period. But contract renegotiations and arbitration cases could reduce oil indexation to less than 50 percent of the total by 2014. We believe this could be a tipping point.

In February 2012, GDF SUEZ confirmed that almost all its long-term gas contracts had been reviewed to increase market price indexation to above 25 percent, to lower oil-indexed prices and to shorten price review cycles. We therefore estimate that an additional 1 bcm of Russian gas has moved from oil indexation to spot indexation as the GDF SUEZ-Gazprom contract was formerly with 15 percent spot indexed.

In March 2012, ENI and Gazprom reached an agreement on gas supply contracts. ENI/Gazprom revised prices and flexibility but didn't disclose details on the agreement reached. We estimate that they agreed a total c.13 percent discount (taking into account renegotiations since 2009) but have maintained a full oil-indexed formula. With this discount, Gazprom gas is now more competitive than Statoil gas, which faces further renegotiations in 2012 (estimated).

In March 2012, E.ON and Statoil agreed a 'structural' solution on long-term gas prices. This is a long-term fix that allows E.ON not to find itself in the loss-making position of paying higher prices for its gas purchases than that obtained on resale. As neither of the companies gave details of the terms of the deal, if we assume that (i) Statoil/E.ON long-term contract is for 15 bcm/y and (ii) 25 percent has already been spot-indexed since the 2009 crisis, then the 'structural' fix means that it is now 100 percent spot-indexed. Our assumptions imply that the deal has moved (since January 2012) an additional 11 bcm from oil indexation to spot indexation.

Thanks to these recent deals, it is estimated that European gas supply could be 55 percent oil-indexed and 45 percent spot-indexed in 2012 (Figure 2).

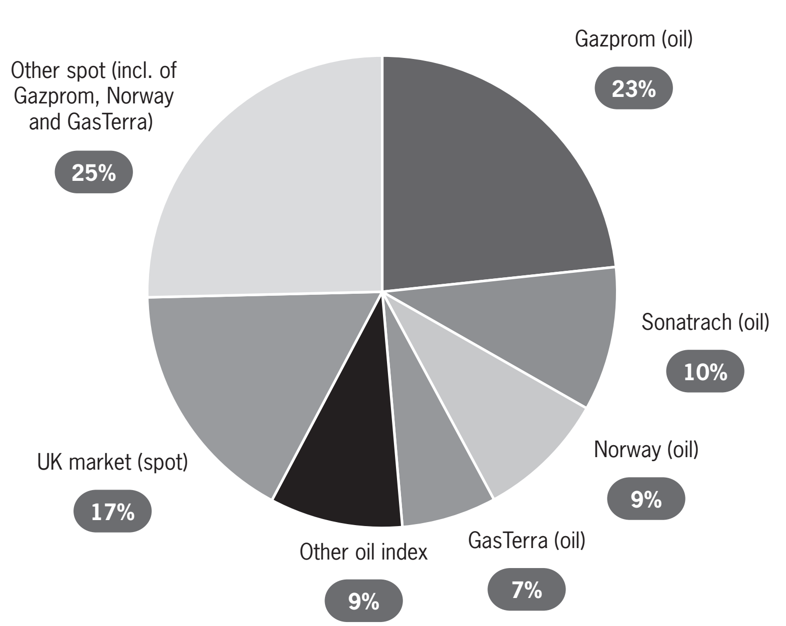
26 bcm of contracted gas from GasTerra are also up for renegotiation. Little information is available on the negotiations. But if we assume those volumes move from 75 percent oil-indexation to 100 percent spot indexation, then the split could even be 51 percent oil-indexed/49 percent spot-indexed.

The closer we get to 50 percent, the more unstable the system is going to be. So oil indexation is facing major challenges. The old system where oil-linked long-term contracts were signed to ensure both security of demand and security of supply and hub spot trading provided additional volumes, is facing a step change. It is estimated that by 2014 oil indexation pricing should represent the minority stake in European gas supply. In Europe, the rationale for oil indexation disappeared many years ago, so hub pricing makes more sense today.

In April 2012, a French court annulled a gas supply contract between ENI and a French gas-fired production plant in an attempt to prevent the latter's bankruptcy. This decision followed the implementation of a safeguard procedure that allows French courts to implement measures to improve the economic situation of a company. This decision could strengthen the buyers' case before an arbitration tribunal.

E.ON, RWE and PGNiG have taken Gazprom to arbitration in an attempt to index more of their contracted volumes to spot prices. The outcome of the arbitration process is difficult to predict and there may still be concessions on prices thanks to ongoing negotiations to avoid arbitration. One possibility is that the arbitrators may decide that the long-term contracts that used to be oil-indexed in the 60s, this being the only price mechanism available at the time, should now be spot-based, since it is estimated that this is the way the majority of gas should be sold in Europe from 2014. Such a decision could help the

Figure 1: European Gas Supply: 58 percent oil-linked in 2011



Source: SG Cross Asset Research

establishment of a single EU gas market and could possibly boost long-term gas demand.

How Long Can Producers Manage this Market?

Thanks to maintenance and production issues, gas producers have managed to keep prices fairly high. A back-of-the-envelope calculation shows that the total European gas demand for 2012e (485 bcm) at 460 \$/1000 cm for the oil-linked and 315 \$/1000 cm for the spot gives an average price in Europe of 400 \$/1000 cm, compared with 80 \$/1000 cm for the USA. For Europe, the 'overprice' in terms of the bill is therefore 325 \$/1000 cm or \$155bn for 2012e (0.9 percent of European GDP)!

The drawback is that gas is a fuel that is losing market share in power generation, as seen in the UK, Germany and Spain. On top of the renewables expansion backed by the EU member states, cheap coal is further displacing gas out of the European energy mix at a time when demand is low. High gas prices (mainly oil-indexed in Germany and spot in UK) make gas-fired power plants uncompetitive vs coal-fired plants as demonstrated by market clean spark spreads that have been lower (and even negative in some instances) than clean dark spreads for over a year.

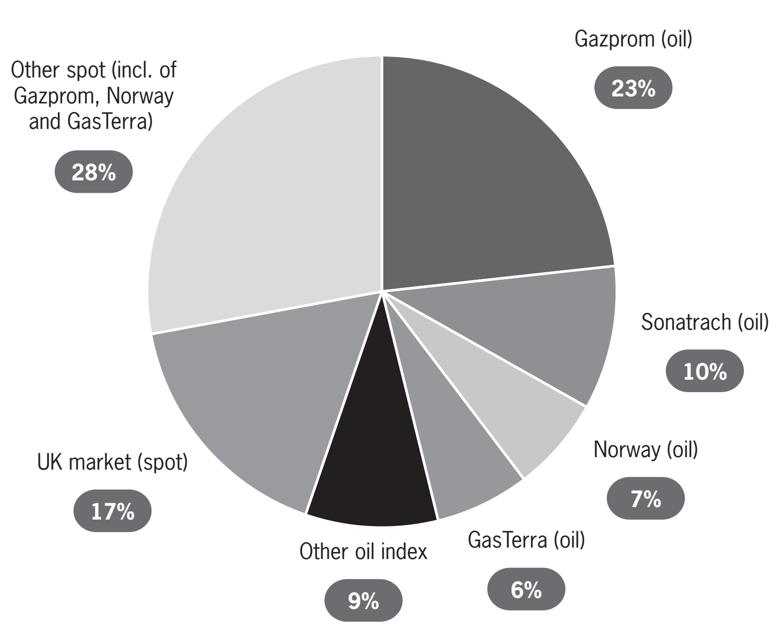
This is also the case in Spain, where a domestic coal support law went into effect in February 2011. Coal-fired plants are displacing combined-cycle gas plants as domestic coal generation is forced into the system. In 2011, Spanish gas demand for electricity was reduced by 19 percent, and this trend is continuing in 2012.

During 2009–2011, the big gas producers resisted major formula changes. They preferred to reduce their production levels while still enjoying the high rents enabled by high oil-linked gas prices. Now, with gas demand further down, the big gas producers are compelled to move, by agreeing to alternative pricing. Even Gazprom has recognised that the long-term contract formula needs to be addressed to enhance the competitiveness of Russian gas in Europe.

More Spot Means better Market Places Are Needed

The USA is the first gas market with 22 percent of the worldwide gas consumption. Thanks to a very liquid and transparent market, Henry Hub is a recognised commodity asset that is widely used by the financial community. With 16 percent of the worldwide gas consumption, the EU is the second gas market. So far, poor hub liquidity and poor transparency have limited access to the financial markets except in the UK.

Figure 2: European Gas Supply: 55 percent oil-linked in 2012e



Source: SG Cross Asset Research

Building on the success of its worldwide oil database (JODI oil), the International Energy Forum is poised to launch a one-month delayed (M-1) worldwide gas database by year-end, comprising freely available demand, supply, stocks and trade data. This database should be of great help to better assess monthly moves in the worldwide gas balance and could help European markets to thrive.

Relying only on hubs for price discovery makes sense in the USA where numerous producers are in competition. This is not the case in Europe where the main external sources of supply in 2011 were Russia (24 percent), Norway (19), Algeria (9) and Qatar (7), giving those four countries and their state-owned company c.50 percent of the market. So, long/medium-term contracts should remain an important tool to ensure risk is shared fairly between buyers and producers. But they will not be the same as previously (30 years, oil-linked). Instead, they could be for ten years and spot-indexed, with a floor and a ceiling to mitigate spot price volatility (in Northern Europe), or with an increased discount to oil (for Southern Europe) and with little volume flexibility, to suit both buyers' and sellers' new requirements.

But moving to a majority gas spot pricing in Europe could further shift the power in the hands of major producers at a time of high demand, if we don't, at the same time, manage to increase domestic production, increase import infrastructure and/or build new storage (to have ability and options to store gas when spot prices are low and withdraw it when spot prices are high).

Europe's gas proven reserves, which have declined by 4.4 percent on a compound annual growth rate in 2000–2010, can only grow if we decide to go for shale gas. And the European gas market will still not be able to function properly unless there is enough domestic production to counterbalance the power of Gazprom, Statoil, Sonatrach and Qatar Petroleum. After implementation of the third energy package, the EU Commission should foster domestic shale production as a diversification to boost not only security of supply but also to finally achieve a fully functioning gas market.

The Gas Exporting Countries Forum – Global or Regional Gas Cartel-in Waiting?

LAURA EL-KATIRI argues that gas markets need not fear any producers' cartel, be it the GECF or others

The GECF was launched at a meeting of energy ministers in Teheran in May 2001, by the governments of Algeria, Brunei, Indonesia, Iran, Malaysia, Oman, Qatar, Russia and Turkmenistan. The organisation describes itself on its website as 'a gathering of the world's leading gas producers aimed at representing and promoting their mutual interests' with the objective of increasing 'the level of coordination and [to] strengthen the collaboration between member countries.'

For the gas market observer, the move may not have been particularly surprising; gas markets themselves had by the early 2000s evolved considerably, not least through the firm growth of trade in LNG. Beginning with modest trade flows in the 1960s, LNG had by the 1990s grown increasingly important, and diluted the traditional, regional trading divide for natural gas, which pipeline trade entailed. The greater the destination flexibility of LNG trade, coupled to evolving contracting practices that involved more options for spot trade and intra-regional arbitrage, meant that gas producers at the beginning of the twenty-first century began to face considerably more choice, but also more uncertainty, than in previous decades.

Consumer-side organisations, such as the IEA which increasingly included natural gas on its agenda, demonstrated the obvious interest of at least some consumer nations to organise their interests; while structural market reforms in buyer countries, such as the liberalisation of the European gas market (notably the second European Gas Directive) at the end of the 1990s confronted natural gas producers with a sudden fait accompli in one of its key markets. Algerian energy minister Chekib Khelil, famously quoted in 2002, may have well summarised the rationale of some of those gas producers forming the GECF, complaining that 'those who have an impact on the market, that is the European institutions, should be aware of our issues. When they passed their legislation, they never consulted us. They never thought of talking to the gas-exporting countries before passing their laws.' The oil market by then already had its own exporters' interest groups, most importantly the Organisation of Petroleum Exporting Countries (OPEC) created in 1960.

Nevertheless, the new gas producers' forum set out initially as a very informal gathering, whose primary instrument was the annual meetings of member states' energy ministers, which generally bore little fruit other than occasional but altogether half-hearted debates around gas pricing mechanisms. An early attempt by Egypt in 2003 to propose a common gas-pricing framework to GECF member states fell entirely on deaf ears. By 2005, the Forum had, in the eyes of some observers, reached the status of an 'evidently troubled organisation' following a catastrophic conference in Trinidad with the attendance of only four energy ministers. With markedly absent Khelil slamming the forum as a 'waste of time' and organiser Trinidad and Tobago lamenting the apparent lack of co-operation and shared interests, the forum cancelled its 2006 meeting and had by then lost almost all of its Pacific members.

The perception of the GECF in the public eye had remarkably turned around by 2007. A successfully organised Ministerial meeting in Doha was overshadowed by controversial statements made in previous months by core members Russia and Iran. In January, Iranian head of state Ayatollah Ali Khamenei had called for the creation of a gas market cartel through the GECF, a 'Gas-OPEC' to control and manage gas export prices. Khamenei's outburst was a week later taken up by Russian president Vladimir Putin, who seemed to add further fuel to the fire at an infamous press conference at which he was quoted saying that the creation of a Gas-OPEC was 'an interesting idea' that he would 'think about'. Both statements triggered a media storm which persisted for another year, in which both media and – shamefully – a number of academics excitedly picked up on every bit of news that could indicate a potential conspiracy of gas producers, such as subsequent, bilateral high level business talks between Algeria, Iran, Qatar and Russia. A business trip by Russian Energy Minister Viktor Khristenko to Algeria in February 2007 to discuss joint projects with Sonatrach subsequently prompted the EU Energy Commissioner to express 'concern' over 'the development of the contacts between Russia and Algeria,' which could 'create a kind of cartel.'

Between Institutional Milestones and Handicaps

Much of the debate surrounding the GECF ebbed away in the following years. With a moderately united message at each Ministerial meeting that the GECF was far from intending to establish a sort of gas market cartel, the organisation instead began to keep a low profile – and to work on internal institution-building processes. The GECF as an organisation still today remains somewhat of an enigma. In 2008, the organisation adopted a Statute, which in very basic terms describes the functioning of matters such as decision-making and membership rights, and drafted out a vague line of interests of its member countries. In 2010, the forum opened a permanent office in Doha, with a permanent secretariat and a Secretary General, Leonid Bokhanovsky. The GECF also opened several, little advertised sub-divisions, such as a research and statistics office, tasked with the supposed development of an own gas market model. The GECF's statute is since September 2010 registered with the UN, providing the Forum with the legal character of an intergovernmental organisation.

While many of these institutional achievements are real and – considering the organisation's comparatively young age – understandably gradual, the GECF remains an organisation far from any move towards cartelisation, or from being an effective producer-interest organisation for that matter. Its handicaps are multiple, and overcoming them may well take more time than many of its members may have. For one thing, the GECF's members remain a volatile, if not unstable bunch whose reserves and production rates differ considerably both in volume and longevity. Of the GECF's eleven founding members, only four have remained member countries until today: Algeria, Iran, Qatar and Russia. While these four countries' weight within the group – owing to the mass of their reserves – is enormous, their interests are anything but aligned. Russia and Algeria, both major pipeline exporters, are direct competitors over their main export market Europe; Iran, barely an exporter at all owing to high domestic demand which has turned the country for many years into a net-importer of natural gas, appears to be undetermined whether to use its gas reserves domestically or for exports; its current lack of sizeable exports also means that Iranian threats of supporting a gas cartel can hardly be backed up by relevant export volumes.

LNG giant Qatar, by contrast, has adopted a perhaps surprisingly quiet stance in the Forum. The country secured the organisation's headquarters for location in Doha, but its apparent silence in and about much of the forum's debate suggests the country's interests are to be found primarily in monitoring other exporters' activities. Smaller members of the GECF such as Trinidad and Egypt are said to be interested in mingling with the 'big' exporters, possibly taking up some of their experience, while participating in anything relevant for their new but comparably smaller LNG export volumes. So far, no OECD countries, such as large-scale producers USA, Canada and Australia, are members of the GECF. Norway since the start, and the Netherlands since 2011, have held observer status, along with Kazakhstan, but have repeatedly declined to become full members. Their intent seems to be to monitor the Forum rather than to influence its actions.

The GECF has consequently suffered from a rather apparent lack of internal clarity over the organisation's realistic short- and long-term objectives. Apart from forming a gas market cartel-like structure, GECF members would have several, potentially fruitful options: to provide a business forum for inter-country dialogue on company cooperation; to become a 'signalling task force' whose role is to guide price levels and/or formulae in short-term markets and long-term contracts, similar to the way OPEC frequently acts as a signaller for crude oil prices; or to function as a producer-based information and data sharing platform, allowing for greater transparency on regional and cross-regional gas markets (a role which would indeed serve the entire gas market). So far, however, none of these roles has been filled, or any attempt made to fill them. Indeed, the evident lack of cooperation in most basic activities such as data sharing underlines the fact that the GECF as an organisation does not speak with a united voice – or barely speaks at all.

The potential undertaking of one day forming a cartel on gas markets, a dubious 'Gas-OPEC' shadowing gas prices in regional markets and cross-regional LNG trade, meanwhile remains constrained by yet another feature. This is the structure of gas markets themselves. The bulk of natural gas continues to be traded under long-term contracts, many under oil-indexation, which decouples prices for contract-gas from price movements in short-term markets. It would be this gas-to-gas link that could enable cartel-minded producers to try to squeeze markets via quota restrictions, provided sufficient support could be rallied by other producers. The cutting of long-term contract supplies by exporters wishing to obtain higher prices for their gas, can be held as nothing but unthinkable for it would be illegal and equivalent to blackmail, rather than quota-regulated supply on the short-term market. The non-existence of liquid spot and forward markets for natural gas in most parts of the world moreover means that linking long-term contract prices to short-term gas prices is an unlikely scenario in the near future. The reality is that gas markets, and the pricing of gas, until today function very differently from oil markets, and do so for a variety of good reasons.

GECF members have gradually come to accept this fact, as seems evident from their unusually united stance in support of long-term, oil-indexed contracts for gas at every single Ministerial meeting since 2009. The reasons for this support may involve an understanding that any undertaking, or threat thereof, towards a cartel-like structure may well render the whole group ridiculous. At the same time, another assumption forces itself on the observer; at a time when oil prices are relatively high, supporting long-term oil-indexation suggests the forum's gas producers are in favour of any contracting practice that maximises revenue. This is not a new or surprising lesson; but it does raise the question of what the forum contributed other than a discussion table to issue already known messages. ■

US Natural Gas – A Tale with many Twists

HOWARD V ROGERS suggests North America's shale gas breakthrough has not yet turned the picture completely

Historical Context

The US shale gas phenomenon and its attendant media coverage have raised (among other issues) awareness of the importance of natural gas in the North American energy mix. The prevailing impression is one of an abundant resource which is out-competing coal in the power generating sector and which is poised to 'go global' if some of the many US and Canadian LNG export schemes are approved and come to fruition. Natural gas in North America has a much longer history than in Europe. The first US gas well was sunk in 1821, in Fredonia, New York, although it wasn't until the 1920s that any significant effort was put into building a pipeline infrastructure for gas. US natural gas production grew dramatically following the end of the Second World War, reaching a peak in the early 1970s and maintaining an undulating plateau thereafter.

The period of the 1970s and 1980s was characterised by confusing and sometimes contradictory policy initiatives and related market fundamentals shifts. For much of this period intrastate and interstate gas trade was subject to separate regulatory regimes which created a fragmented market landscape and supply distribution bottlenecks. Supply difficulties during cold winter periods gave rise to a belief that the underlying problem was a resource constraint. Although this was largely overcome through deregulation by the early 1990s, both the Clinton and Reagan administrations had promulgated incentives to accelerate drilling to augment gas production. The gas supply 'bubble' of the 1990s became a 'sausage' and as a consequence the oil and gas Majors sought offshore US (Gulf of Mexico) and international investment opportunities in preference to those of the US onshore Lower 48. From a policy and industrial consumer perspective the experience of the 1990s gave rise to a view that natural gas was a plentiful, competitively priced resource, as evidenced by the surge in investment in Combined Cycle Gas Turbine (CCGT) generation. Between 1998 and 2003 some 220 GW of new CCGT capacity was built in the USA, boosting total generation capacity (all fuel and technology types) by 28 percent (Rogers, 'LNG Trade Flows in the Atlantic Basin', OIES).

A New Millennium and a Tightening Market

Although it was not widely appreciated at the time, the gas bubble/sausage was eroded in the second half of the 1990s, manifesting itself as a narrowing gap between gas production capacity and actual production. By 2000 this 'buffer' had been virtually eliminated. Between 2000 and 2005 the US gas market experienced higher gas price volatility.

The causes of price volatility in the period 2000 to 2006 included cold weather episodes coinciding with lower than average underground gas storage inventory, hurricane-induced production shut-ins in the Gulf of Mexico Offshore (of note Hurricane Katrina in August and September 2005), and a tightening international LNG spot market towards the end of the period. Despite a rising trend in both gas price and rig count, US domestic production fell by 2.1 percent per year on average between 2001 and 2005. As this trend of falling production became evident, two almost independent supply-side responses were set in motion.

Two Tribes

The oil and gas majors began developing large gas discoveries in the international arena to form integrated LNG supply chain projects with a peak of new project approvals reached in 2005. The most notable of these were the Qatari LNG projects but in the same 'wave' can be included projects in Russia (Sakhalin), Yemen and Indonesia (Tangguh). The intention with much of the LNG associated with these projects was to keep it 'destination flexible'; however the investment in North American LNG import regasification terminals is testament to the expectation of the need for significant LNG imports into the USA by the end of the 2000s. Total North American LNG import capacity stands at 200 bcma, of which 170 bcma is in the USA.

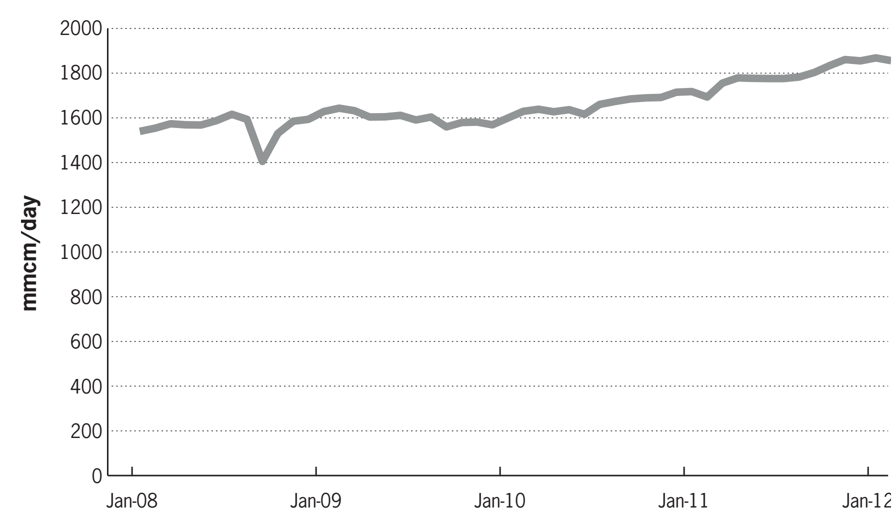
The US independents had been experimenting with combining horizontal drilling technology with hydraulic fracking to improve the well flowrate of natural gas in shale rocks, whose presence they had long been aware of through exploring for conventional gas. Shale gas is natural gas that remains captive in the relatively impermeable strata in which it was originally formed from the transformation of marine organic matter under high pressure and temperature. By 2006 shale gas production volumes were becoming significant, by 2010 they accounted for 23 percent of total US natural gas production.

In the latter half of the 2000s, despite net exports of gas to Mexico increasing, pipeline imports from Canada and LNG imports in general decreasing and US gas consumption (especially in the power sector) growing significantly, the USA from 2006 onwards developed a fundamental problem of oversupply – reflected in a growing inventory of gas in underground storage facilities. In this era of 'supply plenty', with Gulf of Mexico gas production less significant than previously, price volatility (except during the financial crisis of 2008) has been generally depressed. Henry Hub prices, which averaged \$12.69/mmBtu in June 2008, during the commodities 'bull run' just prior to the financial crisis, have since that time trended downwards, averaging just \$1.95/mmBtu in April 2012.

I See no Ships

The wave of new LNG supply, much of which was intended for the American market, came on stream in late 2009 and 2010. It was absorbed by a post-recession rapid rebound in demand for LNG in the Asian markets of Japan, South Korea, Taiwan, India and China and in Europe, which suffered abnormally cold winter conditions at the beginning and end of 2010 (and hence high space heating demand). Nevertheless the impact of recession and the position of plentiful supply in Europe created a wide differential between oil indexed pipeline gas under long-term contracts (principally from

Figure 1: US Monthly Gas Production January 2008–February 2012



Source: EIA

Russia) and traded gas hub prices, creating a strong preference for LNG supply sold on the European hubs. With limited LNG remaining after meeting Asian and European demand, US LNG import terminals in 2011 experienced a 6 percent utilisation rate; 3 percent for the first four months of 2012.

US Gas in 2012: After the Gold Rush?

In 2012, US gas production comprises conventional gas 70 percent (but in decline), shale gas 25 percent plus, with the balance being Coal Bed Methane. Due to typically rapid production decline of shale gas wells in their first year of operation, the underlying decline rate for total US natural gas production has deteriorated; in 2001 it was 23 percent per year, in 2011 32 percent. This translates into some stark statistics vis-a-vis how much production needs to be added each year from newly drilled wells to keep aggregate production level: in 2001 this was 124 bcma, in 2012 it is 227 bcma (broadly equal to twice the annual gas production of Norway). At the Henry Hub prices of $2.00/mmBtu prevailing in 2Q2012, production replacement is becoming a huge challenge. Michelle Foss ('The Outlook for US Gas Prices in 2020', OIES) estimates the Henry Hub price required to remunerate fully the build-up cost of dry shale gas at around $6/mmBtu. Clearly on this basis, current investment in dry shale gas is value-destructive and not sustainable. This is borne out in an analysis by Arthur E. Berman of the financial results of the 34 largest US shale operators in 1Q 2011 when the Henry Hub price was $4.2/mmBtu. Free cash flow generation in the quarter was $12 bn, but capital spend was $22 bn – resulting in a net cash injection requirement of $10 bn – from new equity offerings, increased borrowings or other means.

The Show Must Go On

Despite a backdrop of deteriorating gas prices, several factors have so far mitigated the economics of shale gas drilling and maintained investment momentum. Operators have been able to sell forward production on the US natural gas futures market, which has consistently been in contango since 2009. The support this has offered over prompt price outcomes however has diminished since that time. Operators who participated in the shale 'land grab' over the past few years regard lease acquisition as a 'sunk cost' in terms of making drilling decisions on a 'money-forward' basis. Landowners often require wells to be drilled within a defined time period, to avoid lease expiry which is an additional incentive supporting the drilling decision. A third factor is the effect of 'farm-in' transactions. These are common arrangements in the upstream business. If a new entrant wishes to access prospective shale acreage already leased it may reach an agreement with an incumbent operator in which the new entrant gains a working interest (equity share) of future shale gas production by paying a disproportionately high share of drilling expenditure and potentially an access fee. This arrangement has the effect of improving the operator's money forward drilling economics but also requires dry shale gas wells to be drilled contractually whereas the operator might have opted to drill more liquids-prone prospects.

To Pastures New

Despite the production momentum maintained in the face of the declining Henry Hub price since 2008, there have been clear signs that drilling activity in dry shale plays is declining. Operators have turned their attention (and drilling budgets) to 'wet' shale plays, which produce NGLs (ethane, propane and butane) and shale oil plays (with associated gas production), where oil price-related liquids revenues trump gas price considerations. Although this re-focusing of drilling still produces gas as a by-product, the volumes of gas production per well drilled are lower, for example in the 'wet' Eagleford play gas production per well is only 25 percent of that of wells in the Haynesville dry gas shale play (based on initial well production rates). The impact of this transition is beginning to show up in EIA data. Figure 1 shows US gas production reaching a plateau in September 2011, commencing a decline in January 2012.

Chesapeake Energy, one of the foremost US shale operators, in January announced a 50 percent reduction in Barnett Shale drilling and a production curtailment due to low gas prices. The Baker Hughes US rig count confirms a pronounced shift from gas to oil drilling since the beginning of November 2011.

Light at the End of the (long) Tunnel?

Of late, much media focus has been on numerous prospective LNG export projects from the USA (where these in the main involve incremental investment to transform LNG import terminals to export facilities) and from the Canadian west coast. With only the Sabine Pass facility approved to date and decisions on other projects likely deferred until after the 2012 presidential elections, the scale of US future export capacity is uncertain, with concern as to the upward impact on US gas prices a key factor. In Canada, approvals may be more easily forthcoming but greenfield investment costs will be higher; nevertheless the Kittimat project in British Columbia looks likely to proceed. While LNG projects offer a means by which 'excess' US production may be exported, it is unlikely that such schemes will commence operations prior to late 2015. This leaves US shale operators with the prospect of at least three more years of a very challenging business environment. While additional gas demand may result from the displacement of coal in the power generation sector further demand gains in the industrial sector are likely to follow an investment lag and moves to establish natural gas as a transportation fuel are likely to take several years to build up a meaningful market share.

Uncertainty in the Medium Term

In 2012 the USA emerged from a mild winter with a high underground gas storage inventory prompting fears that if production continued at year-end 2011 levels it would be likely that the end of the 2012 injection season could see Henry Hub prices testing new lows due to lack of adequate storage space. If dry shale gas drilling continues to slump and is not compensated by associated gas production from wet shale gas and shale oil drilling, this fear may be overtaken by concerns over falling total US gas production.
If such a trend becomes established, it would trigger upward pressure on Henry Hub prices. Such a rise in those prices would be restrained for a period by fuel switching in the power sector. As gas prices rise relative to coal, a reversal of the recent switch from coal to gas would take place at gas prices in the range $3 to $4/mmBtu. On eventually reaching $6/

mmBtu one might rationally expect an increase in dry shale gas drilling activity; however given the recent financial pain suffered in this sector and the more secure alternative of shale plays driven by crude oil prices, this increased activity may be slow in materialising, resulting in a classic commodity cycle price overshoot for gas. Assuming that at some point high US gas prices do result in renewed dry shale gas drilling activity, the key question is 'what is the shale gas production response to higher prices?'

Despite the high gas resource numbers quoted for the various US shale plays, ultimately the only meaningful assessment is the volume of gas that will flow through commercially viable wells. In the US plays so far developed, activity has concentrated on the play 'sweet spots' – the areas where well flow rates are highest and which best support economically viable production. These sweet spots may account for only 10 percent of total play volumes and already there are signs that the costs of incremental production additions on the Haynesville and Barnett plays are showing diminishing returns, i.e. that the best parts of the play have already been exploited. Given the inherent uncertainty over well flow rates from future wells on a shale play, the likely volume of viable production at higher future Henry Hub prices is a huge uncertainty. Yet this is exactly the nub of the issue when decisions on whether to authorise additional future US LNG export projects are considered.

If the shale production response to higher prices is poor, despite drilling investment forthcoming, then Henry Hub prices will rise, and LNG export economics will deteriorate. In this scenario, eventually the USA may be required to import higher quantities of LNG in which case Henry Hub would need to rise to European hub price levels in order to compete for available LNG supplies.

If the shale production response to higher prices is highly positive then abundant production growth would be available both to supply LNG export projects and at the same time meet US natural gas consumption needs at moderate (circa \$6/mmBtu) prices.

Conclusions

The US natural gas arena has, over the past three decades, undergone significant regulatory changes that have interacted with its supply-demand-price dynamics. The decisions required on whether to allow the export of significant volumes of LNG might have equally significant consequences. In an optimistic scenario for dry shale gas production (in terms of its production volume–price response) they could establish an arbitrage-driven linkage between a sustainable Henry Hub price and the destination markets of the European gas hubs and the Asian LNG spot market. In a less optimistic scenario for a dry shale gas production–price response, such LNG export schemes could become stranded assets should the USA in time need to import LNG to meet its gas consumption requirement. Prior to the start-up of US LNG export projects (2015 at the earliest), the industry will be subject to rationalisation in order to establish a more sustainable price level. Data on US production and rig counts indicate that this has already started. This is unlikely to be a smooth transition to a new equilibrium state, rather a classic commodity supply–price overshoot. The story of US natural gas is likely to yield a few more twists before the tale is concluded. ■

Australia LNG – Will the Growth in LNG Production be Maintained?

DAVID LEDESMA considers Australia's upcoming LNG potential

Background

Australia is fortunate to be endowed with considerable natural resources, not only for energy products, but also coal, metal ore minerals and precious stones. With 133 tcf gas reserves it is a major gas resource owner, the largest in Asia and ninth largest in the world. Australia, however, is a large country and its gas reserves tend to be located in remote locations and this, together with the small population of the country and its modest annual gas consumption (in 2011 26 bcma compared to 105 bcma in Japan and 80 bcma in the United Kingdom) means that, in order to commercialise its gas, capital-intensive LNG export schemes have had to be developed. Australian companies, supported by the Australian government, have been following this strategy since the successful start-up of the North West Shelf project in 1989, but only since 2010 has the industry seen a serious increase in the growth of LNG export projects sanctioned. In 2011 Australia exported 26 bcma LNG, through two LNG projects (the same amount of gas as it consumed domestically). LNG exports in 2011 were valued by the Bureau of Resources and Energy Economics at A\$11 bn, approximately 6 percent of Australia's energy and resources export earnings.

It is the planned future growth of Australia's LNG exports that will change the face of LNG globally with the country expected to overtake Qatar as the largest supplier of LNG before 2020. In addition, the country is the first to spearhead LNG production from coal bed methane (also known as coal seam gas), which can be produced in commercial quantities when the coal is de-pressurised and de-watered through drilling and the application of suitable well technology. This is a development that was not thought feasible ten years ago. Developers expected the location of the coal seam gas LNG plants on the East Coast – nearer to the main population centres and with an onshore gas supply – to lead to lower cost LNG export plants when compared to those located on the more remote, and environmentally sensitive, north-west of the country which are based on offshore gas reserves. The extent to which the East Coast LNG projects will be cheaper than the conventional gas projects of the northwest is still to be proven. This rapid growth of LNG export investment is causing substantial challenges to project developers as projects compete for resources, human and financial.

This article will examine the LNG projects that are under development and look forward to see how the Australian LNG sector can expand further in the future. It will also discuss Australia's competitiveness for future LNG supplies in the next decade.

Australian LNG Projects

Operational and Under-Construction

There are currently three LNG plants operational in Australia; the North West Shelf (16.3 mt), Bayu Undan Darwin (3.2 mt) and Pluto (4.8 mt). The Pluto project is the most recent to start operation in May 2012, eighteen months late and with serious cost overruns. In 2006 the project was planned to cost US$8 bn but by the time the project was operational, project costs were reported to have increased to US$14 bn. That said, once the project started it increased its production level to near nameplate capacity in less than a month.

There are currently seven projects under construction with a total capacity of 61.3 mt, of which three are located on the East Coast of Australia near the town of Gladstone and which will use onshore coal seam gas as feedstock to the plant. The other four are located in the north-west of the country and will use offshore conventional gas. Table 1 shows the capacity of the projects currently in operation and details of those under construction.

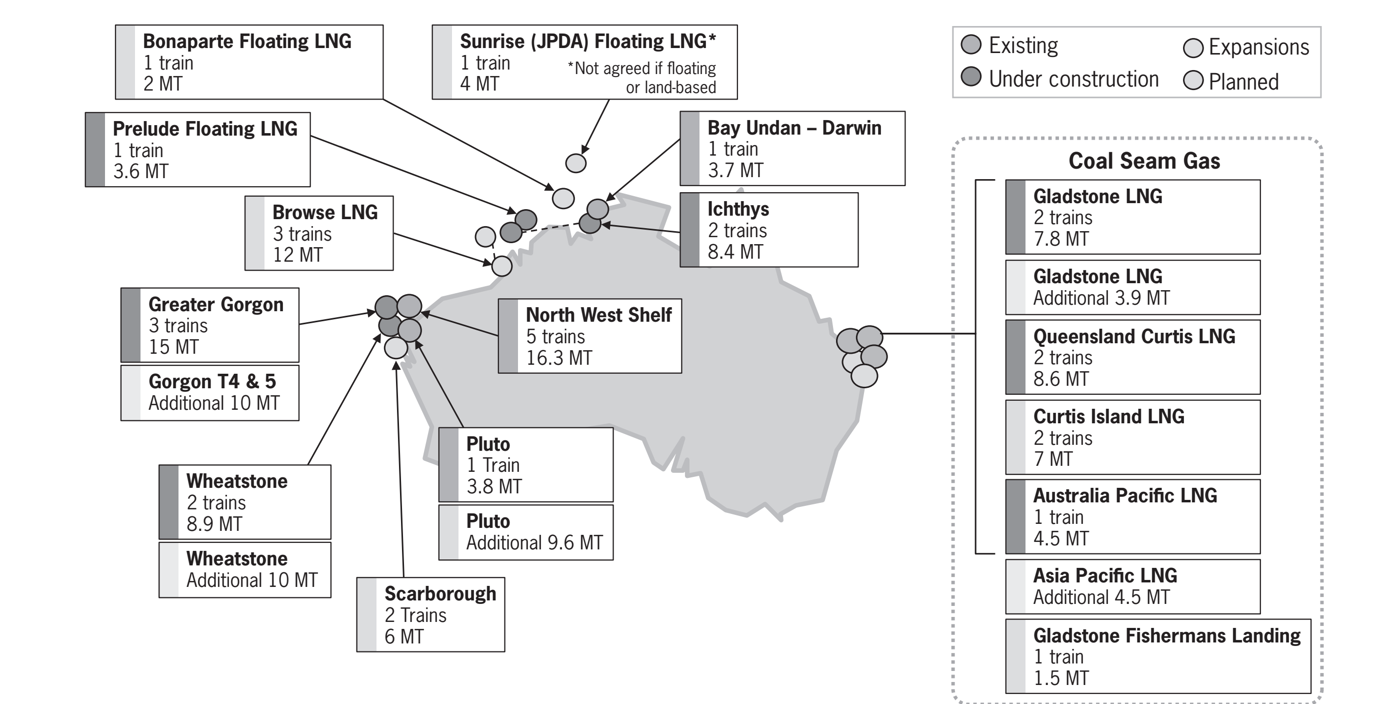
The projects that are currently under construction will face considerable challenges to deliver the LNG by the dates stated by their sponsors. In May 2012 BG announced that the cost of its Queensland Curtis LNG project had increased by 36 percent to US$20.4 bn and, in June 2012, Santos reported that the cost of its Gladstone LNG project had increased by 16 percent to $18.5 bn. The Gladstone cost overruns are also having an impact on the financial results of the sponsor companies: on the day the overruns were announced, the Santos share price fell, wiping half a billion dollars off the company's share value. Project developers say that the increase in costs is due to cost input inflation (some due to the strong Australian Dollar), landowner disputes and drilling delays.

While the liquefaction technology being used is proven and has been used in many LNG projects worldwide, gas from coal seams needs many low-flow rate gas wells to be drilled over the period of the twenty-year project life compared to the fewer high production wells from conventional gas sources. The coal-seam gas wells cost less, but it is the sheer number of wells, the logistics of drilling completion, hook-up, de-watering and the operation of these wells that is causing the developers problems. Most of the upstream gas supply cost is in the infrastructure needed to compress, gather and move the gas to the LNG plant and this requires a lot of labour, which is in short supply, particularly in specific skillsets. The project developers have tried to pass this cost risk to the contractors who are constructing the plants, with varying success, but further cost increases and delays may well be announced in the future. In July 2012, Origin Energy, a shareholder in the third Gladstone LNG project, said that there had been no significant change in the $20 billion project costs estimated for Asia Pacific LNG in 2011 when the joint venture approved the first

Table 1: Liquefaction Capacity in Operation and under Construction in Australia (mtpa)

Plants in Operation		24.3
Plants under construction		
Using conventional gas as feedstock	40.4	
Using coal seam gas as feedstock	20.9	
Total under construction		61.3
Total capacity of all plants		**85.6**

Figure 1: Australia LNG Export Projects



Source: South-Court Research

train, other than changes due to foreign exchange rates.

The local population is also complaining about the large number of wells and connecting pipelines that are being constructed or are planned to be built. In a recent report from Sanford C Bernstein & Co, it was said that companies had underestimated the number of wells needed to be drilled to support the three Gladstone projects, estimating an eventual total of 30,000 wells compared to an initial estimate of 18,000. The companies are also having problems firming up the required coal seam gas reserves, Santos has agreed to purchase gas from Origin for ten years from 2015 and this gas, together with gas from its conventional and unconventional gas reserves in the Cooper Basin, is planned to make up the potential supply shortfall for its Gladstone LNG project. BG has also secured gas for the ramp-up phase of its Queensland Curtis LNG project from Origin and ConocoPhillips.

In addition, there is a degree of company restructuring underway as project sponsors seek to manage higher costs and project delivery. BG is looking to sell 20 percent of its Australia interests and CNOOC, which has already signed a 3.6 mtpa LNG offtake agreement with Queensland Curtis LNG and has a 10 percent stake in train 1, is rumored to be a potential purchaser. The author understands that the reason for the sale is that BG wants to raise capital to support development of its planned energy projects in Brazil and East Africa. At the time of FID on the second train of Asia Pacific LNG in July 2012, Origin said that its share of the project costs would be funded by selling off a further 7.5 percent of equity in the project (in January 2012 Sinopec paid $1.1 billion to raise its stake by 10 percent from 15 percent). This means that additional equity will become available to investors from this project as well.

The four LNG projects based on conventional gas reserves may not be facing gas reserve shortages, but they could well incur severe delays and cost overruns, though, as at June 2012, none had been announced. Chevron are still planning to start train 1 of the Gorgon project by the end of 2014, but it remains a challenging and expensive project with CO_2 injection in the upstream and the plant being located in a wildlife reserve. The Shell sponsored Prelude project will be one of the world's first floating liquefaction facilities. At 488m long, 74m wide, and weighing about 600,000 mt it represents a considerable technical challenge but, with Shell as a sponsor, it is expected that the facility will be operational by 2017/18. The Wheatstone and Ichthys projects are both in different stages of construction with planned start-up in 2016 and 2017 respectively, though some commentators believe that these dates could slip. Figure 1 shows details of the LNG export projects.

Additional Projects under Development

There are also a plethora of other projects that are under consideration by project developers, many of which are expansions of projects that are currently under construction (Table 2). These projects face development challenges and may not all go ahead.

A key challenge in developing new LNG projects is cost. Over the past five years, the cost-base of LNG projects has increased, reflecting rising contractor and raw material costs. As a result, the Australian projects that are currently under construction are the most expensive LNG projects in the world. The question is – will new projects be as expensive? If they remain high cost, then other potentially lower cost projects elsewhere, such as East Africa, Russia and in the Atlantic Basin (including USA) could be developed ahead of the new Australian capacity. New CO_2 regulations in Australia may result in an increase in costs but, that said, a key factor supporting the development of new LNG capacity is that it will be, in many cases, an expansion to existing projects. Capital costs for expansion projects are normally 60–70 percent of that of new builds, as the expansion projects can take advantage of already developed infrastructure including existing site preparation, tankage, jetty and berthing facilities and utilities, even though, in some cases, additional storage and berths may be required. With the exception of the planned US Gulf LNG export projects that are being developed around existing regasification LNG import facilities, and potential de-bottlenecking of the Qatari LNG trains, most of the other new LNG projects that are planned outside Australia are greenfield and are likely to be less competitive than Australian expansion projects. Also, Australia is located close to the high value markets of Asia, which are currently willing to pay LNG prices high enough to support new LNG projects, with buyers who are willing to underpin projects with long-term take or pay LNG offtake agreements. These factors could well support the development of new Australian LNG export capacity ahead of the competition.

The availability of finance could also be a restricting factor in the development of new LNG projects. Tightness of third party project finance, due to the global financial credit squeeze and new Basel III regulations, could limit the number of new LNG projects that are developed. Developers of LNG projects are already turning to their own funds and debt

Table 2: Other potential LNG Export Projects under Consideration

Gorgon Train 4	Expansion	5.0
Gorgon Train 5	Expansion	5.0
Queensland Curtis (QCLNG) Train 3	Expansion	4.3
GLNG Train 3	Expansion	3.9
Wheatstone T3	Expansion	4.5
Wheatstone T4	Expansion	4.5
Pluto Train 3	Expansion	4.8
Pluto Train 4	Expansion	4.8
Curtis Island	Greenfield	7.0
Bonaparte	Floating	2.0
Sunrise	Floating	4.0
Scarborough	Greenfield	6.0
Gladstone Fishermans Landing	Greenfield	1.5
	Total	**57.2**

raised against company balance sheets, rather than non-recourse project finance, with only three out of the seven LNG projects under construction using third party debt financing. Lenders will seek to lend to those projects that carry the lowest risk and seek greater equity injection from shareholders and finance cover from Export Credit Agencies. Therefore, it will be easier to develop expansion LNG projects that can use income from existing production to fund part of the construction of new trains and which use proven technology and infrastructure. Projects that use new technology, such as floating LNG, may find it difficult to raise finance until the new technology has been proven. This was the case with the Shell Prelude floating LNG project which is being funded from shareholder funds with, until at least after start-up, no recourse to third party finance.

Concluding Remarks

Domestic gas demand growth will remain restrained in Australia due to the size of the country and its relatively low population. This means that, to commercialise large gas reserves, companies will have to continue to develop gas export projects, which effectively means LNG exports. New projects that are developed will primarily be expansions to existing facilities, due to the cost competitiveness of the expansion projects when compared to greenfield developments in Australia and elsewhere in the world. These projects will target the high value markets of Asia. Asian buyers will seek to negotiate lower prices as they are being offered alternative gas supplies from North America, but there is a limit to the volume of LNG that can be supplied from the USA on a US 'Henry Hub' pricing basis. Asian buyers will also not want to buy extensive LNG volumes from North America for security of supply reasons. Australian projects must endeavour to keep their costs down and, if delivery and start-up of the projects currently under construction are delayed, then this may impact on support for future project development. But even with these concerns, Australia will be the largest LNG-exporting country before 2020 and it can be expected that it will maintain this position well into the next decade, and probably beyond. ■

Russian Gas: The Next Ten Years

SIMON PIRANI sees change in the way in which Russia will produce and market its gas in the future

The way that Russia produces and markets natural gas will change substantially over the next decade. The main drivers of change may be grouped under four headings. First, production will shift geographically, away from its historical base in western Siberia. Second, the industry's corporate make-up will change, with Gazprom losing share to others. Third, a related process, domestic market liberalisation, will probably be the most important determinant of change in the way that Russian gas is sold; a further decline in Russia's share of the European market is a possible corollary. Fourth, while exports to Europe are likely to become less important, Russia will continue its long-standing endeavours to open up Asian markets. This article suggests ways that these four processes might play out, and offers some conclusions.

The Resource Base

A historic shift of Russian gas production is underway, away from its traditional heartland – the three now-declining supergiant fields (Urengoy, Yamburg and Medvezhe), and other dry gas resources, in the Nadym-Pur-Taz (NPT) region of western Siberia. A big part in replacing these resources will be played by the Yamal peninsula fields, which start producing this year: Gazprom estimates they will contribute up to 150 bcm by 2020. The pipeline taking gas to Russia's main transportation system from the first Yamal field, Bovanenkovo, began to be filled with linepack gas in June. Production of wet gas from deeper layers in NPT – much of which is owned by non-Gazprom companies – will grow, too; Gazprom has estimated that gas with high liquids content (propane, butane, ethane, etc) will account for 46 percent of total Russian output in 2016–2020, and 59 percent in 2021–2025. Output from the Zapolyarnoe field will continue to rise. Further out, fields in the offshore Arctic, and east Siberia (probably starting with Kovykta and Chayanda), are likely to be significant.

The west Siberia fields were developed in Soviet times; Zapolyarnoe, the main field developed in post-Soviet times, was financed largely by the state, Gazprom's main owner; the Yamal peninsula development began the same way. But future fields will increasingly be developed on a commercial basis. Moreover, the new fields are generally deeper, more distant, and more technically challenging than west Siberia's easily accessible dry gas resources.

The changeover is accelerating. Gazprom managers stated recently that output from Nadym-Pur-Taz – including the big three fields (Urengoy, Yamburg and Medvezhe), plus the Yubileinoy, Komsomolskoe and West Tarkosalinskoe fields – will fall from its current level of around 400 bcm (out of Gazprom's total 513 bcm in 2011) to about 300 bcm in 2015 and 230 bcm by 2020. So these fields, which have been the industry's backbone since the late 1970s, will in ten years' time account for one-third, or less, of total Russian gas output.

The Corporate Picture

Future field development will strike a contrast not only with the start-up of the west Siberian fields, which was accomplished by Soviet planning, but also with the near-monopoly in production and marketing enjoyed by Gazprom up to the mid 2000s. Since then, the government has tilted the regulatory balance towards (i) the oil companies, for whom both access to pipeline capacity and meaningful well-head prices for associated gas were elusive, let alone a framework to incentivise natural gas production, and (ii) Novatek, Russia's second-largest gas producer.

Market liberalisation, complete with a third-party access regime for transportation, remains a government aim that has been stated but not implemented. Gazprom's export monopoly, enshrined in law in 2006, will probably remain, with non-Gazprom producers' access to export markets restricted to LNG producers. But domestic market rules are changing. The government has insisted that pipeline capacity be made available for more non-Gazprom gas; sanctioned long-term supply contracts between Novatek and large state-owned power firms; and taken measures to reduce flaring of associated gas.

The results are striking: non-Gazprom producers now account for between one-quarter and one-third of the domestic market. Their aggregate output rose from 71.3 bcm (11.9 percent of a total 595 bcm) in 2002, to 104.1 bcm (15.9 percent of a total 652.7 bcm) in 2007, and then raced upwards to 160.7 bcm (23.9 percent of a total 670.5 bcm) in 2011.

An indication of the *potential* growth of the non-Gazprom share of production is Novatek's projection that by 2020 it will rise to 300 bcm (35.8 percent) of a total 838 bcm. (This not only assumes that Gazprom's output growth will be much slower than that company itself projects, but also implies an extremely optimistic view of demand growth.) A key factor is that the non-Gazprom producers have quite substantial resources that can be developed at lower cost than many of Gazprom's new fields.

The government's determination to move away from Gazprom's near-monopoly can also be seen in changes to upstream taxation. From 1 January this year, Mineral Resources Extraction Tax (MERT) on gas produced by Gazprom and its subsidiaries increased sharply, to 509 r./mcm from 237 r./mcm last year. Non-Gazprom producers pay a lower rate, 251 r./mcm, on the grounds that they have no access to export revenues. There is a debate in government about how and when the rates will converge: one proposal would tie the MERT rate to converging domestic and export gas prices.

The outcome of these discussions will help determine the order in which new fields are developed. Only time will tell whether the balance will be tipped as far in the non-Gazprom producers' favour as Novatek's projection implies, i.e. to bring their share of total output to more than one-third by 2020.

"… the idea of Russia using gas as an 'energy weapon' for political ends will be useless as an analytical framework in the next ten years."

Russian, FSU and European Markets

The changes in the geographical origin and corporate stewardship of Russia's gas will be matched by changes, just as far-reaching, in the markets where it is sold. Until the mid 2000s, under Gazprom's near-monopoly, the volumes of Russian gas exported to Europe were about one-third of what Russia consumed itself, but they contributed about two-thirds of Gazprom's sales income. The increase in gas prices in Russia and the much sharper increase in the largest FSU importer, Ukraine, have altered the balance. So European sales now contribute only about half of Gazprom's gas sales income, instead of two-thirds. A greater share is contributed by sales to FSU buyers, which rose sharply in 2011 to more than $21 billion – largely due to the completion of Ukraine's transition to European-netback-related import prices. Gazprom's gas sales in Russia are also growing in revenue terms: in 2011 they were about $25 billion.

Domestic market liberalisation, then, will not only change consumption patterns in the world's second-largest consumer of gas after the USA, but also generate much greater revenues from gas sales for producers – and become of correspondingly greater strategic importance for them.

As part of the reform, regulated wholesale prices are rising slowly. In 2011 they were, on average, 2746.7 rubles ($84.18)/mcm, and prices in the unregulated market surpassed 3000 r./mcm. These are roughly a quarter of European price levels, and one-third of what Ukrainian industry pays. The government's aim, of raising prices to a European netback level (i.e. equal to the price of Russian gas exported to Europe, minus additional transport costs and duties), is now expected by economics ministry officials to be achieved by 2021. By then, though, the process of bringing prices to European netback levels may itself be superseded by other means of creating a Russian market with its own price dynamics, which – despite much political foot-dragging – stands out clearly as the government's long-term goal. Another element of liberalisation is the re-establishment of the gas exchange that operated experimentally in 2006–09, on which volumes are sold at unregulated prices: this will probably move ahead only when the government is convinced that balance is restored to a market that has been oversupplied.

Far-reaching changes in the European gas market are also impacting Russia. In the decade prior to the 2008–09 economic crisis, the *volumes* of Russian gas going to Europe generally rose, but its *share* of imports to Europe fell. Since the crisis, and the consequent fall in European demand, the wide differential that has opened between the price of gas sold at 'hub' prices and that sold on long-term contracts has provoked conflict between Gazprom and its European customers. With the tide turning against oil-linked pricing in Europe, and the prospect that gas-to-gas pricing will soon dominate, Gazprom has offered stiffer resistance to these changes than other importers – and, in the short term, has braved reductions in the volumes it delivers to some contract buyers. Its repeatedly stated policy is not to compromise on price, even if it loses sales volumes. And with the European market likely to remain oversupplied until the middle of this decade, Gazprom's share of imports may fall further. But there is little evidence that this is a long-term (i.e more than five years) phenomenon. The recovery of European demand to pre-crisis levels is being delayed, but if and when it takes place – and if it coincides with a growth of LNG demand elsewhere – Russia is the most obvious source of additional imports.

It seems unlikely, then, that Russia's position as the largest source of gas imports to Europe will change. But as revenues from domestic and FSU markets continue to grow, the volume of gas exported to Europe may not rise, and the strategic priority accorded to it will surely fade. (One question arising from these prognoses is: what is the logic of adding to the extra export capacity provided by the Nord Stream pipeline, by building South Stream?)

Russian Gas for Asia

Russia has over the last 15 years set out ambitious plans to open up gas export routes to Asia – but its lack of success in implementing them has been striking. Nevertheless, the government's sights remain set on building both export pipelines and supply infrastructure for Russia's own territory east of the Urals, which is scarcely touched by the gas supply system built in Soviet times.

The only notable export project successfully completed in the Asian part of Russia is the Sakhalin II LNG plant (developed under production sharing legislation by Shell, Mitsubishi and Mitsui, with Gazprom taking a controlling share in 2007). Exports of LNG began in 2009. But Russia has so far failed in its most important Asian objective, to conclude contracts with China for 65 bcm/year of gas sales, as envisaged in a memorandum between the two countries signed in 2006. The main outstanding issues in long-drawn-out negotiations appear to be price, and price formation: essentially, China is not prepared to pay prices comparable to, or linked to, those of Russia's exports to Europe.

The weakness of Russia's position has been underlined by China's success in building the Central Asia–China pipeline and securing agreements to import up to 65 bcm/year of gas from Turkmenistan, the former Soviet Union's second largest producer. These imports began in 2010 and are likely to reach 20 bcm this year. From 2014 China will increasingly be supplied from Turkmenistan's new supergiant Galkynysh (South Yolotan) field. These rapidly expanding Turkmen sales to China have not only ended Russia's position as a nearly monopsonistic buyer of central Asian gas, but also weakened further Russia's bargaining position on its own exports to China.

With central Asian gas flowing to western China, plans to send west Siberian gas there via a mooted Altai pipeline are unlikely to materialise. But the economic

"European sales now contribute only about half of Gazprom's gas sales income, instead of two-thirds."

logic of developing Russia's substantial east Siberian gas resources – to supply China and other East Asian buyers with pipeline gas and LNG, and with the added bonus of gasifying local regions – remains compelling. So it seems likely that at some point in the next decade the obstacles to such development will be removed. The lead times involved mean that volumes in any way comparable to Russia's exports to Europe, or to FSU buyers, will not reach Asia until the 2030s. Nevertheless, the opening of this route would lay the basis for a completely new facet to the Russian gas industry, which since its foundation has almost exclusively supplied European Russia and westward export routes.

Some Conclusions

There is no doubt that the geographical and geological base of Russia's production will move, and little doubt that western Siberian 'wet' gas and Yamal peninsula resources will dominate the new profile. It seems very likely that Gazprom will cede shares of the Russian market to its corporate rivals, but it is harder to say how far and how fast the market will be liberalised. Russia will surely remain the world's largest producer; and while its share of the European market may continue to fall, that is far from certain. It is even more difficult to forecast how it will fare in Asia.

As for the role that gas plays in shaping Russia's place in the world, it may be stated confidently that the idea of Russia using gas as an 'energy weapon' for political ends will be useless as an analytical framework in the next ten years, just as it proved to be in the last ten. Whatever western observers, and some Russian political leaders, thought, in practice Russia's activity on export markets was directed mainly to strengthening Gazprom's commercial position. This was very rarely trumped by political considerations. And Russia's ability even to pursue commercial aims was constrained by market conditions. With the sharp fall in gas demand that followed the economic crisis of 2008–09, Gazprom found it hard to defend commercial bridgeheads, let alone use gas to stake out political ones. Far from flooding Europe with cheap gas that could then be cut off for political reasons, Gazprom preferred to cut exports in pursuit of its commercial objective of keeping prices high.

Take, for another example, Russia's two crucial 'gas wars' of 2009, with Ukraine in January and Turkmenistan in April. The shutdown of transit through Ukraine, however it began, was certainly seen by Russia's political leadership as an opportunity to 'teach Ukraine a lesson'. But the gains achieved in settlement of the dispute were commercial – chiefly, a steep increase in Ukrainian import prices, and strong German support for the Nord Stream pipeline as a transit diversification project. It was the Ukrainian electorate, not Gazprom, who removed Viktor Yushchenko as president and ended his pro-Nato foreign policy orientation. In the dispute with Turkmenistan, Gazprom (presumably in breach of contracts) sharply cut imports. Here, Russia acted out of commercial necessity – in response to drastic oversupply in its own, and European, gas markets – and thereby undermined its own strategic interests in central Asia (by reaffirming Turkmen determination to develop its relationship with China). Moreover, Russia weakened its own hand in talks with China about export prices. What kind of an 'energy weapon' was that?

Contrary to the 'energy weapon' dogma, a more convincing analytical framework considers Russia's heavy economic dependence on exports, of both oil and gas, as a factor that weakens it on the world stage. In the last ten years, Russian governments have repeatedly acknowledged the importance of economic diversification, but progress has been at snail's pace. If oil prices in the next decade are on average higher than in the last decade, as seems likely, it is hard to see what will trigger any breakthrough. On this view, dependence on raw materials exports – together with demographic decline, Russia's stagnation relative to China, and so on – will continue to weaken its position in the world economy, and, consequently, in world politics. This is a more pressing set of problems to think about than the 'energy weapon' discourse, which may now be abandoned. ■

China's Gas Expansion

KEUN-WOOK PAIK traces China's growing role in driving world natural gas demand

At a gas conference in Kuala Lumpur on 5 June 2012 the IEA stated that consumption of natural gas could rise by 17 per cent by 2017, and that Asia will be by far the fastest growing region, driven primarily by China, which will emerge as the third largest gas user by 2013. The driving force of this expansion is the Chinese authority's effort to reduce its heavy dependence on coal use and to increase significantly the role of gas in the country's energy balance.

According to BP's *Annual Statistical Review of World Energy*, at the end of 2009 China's total proven gas reserves were 2.9 tcm, and the reserves-to-production (R/P) ratio was 29.0. This somewhat conservative estimate, however, has done little to dent Chinese confidence in its ability to expand domestic capacity. In November 2004, an authoritative report on China's energy future was prepared by the State Council's Development Research Centre (DRC) under the title 'Research on National Energy Strategy and Policy in China'. This advocated the greater use of natural gas as a clean alternative to coal, in particular in the power and residential sectors. It also stressed the importance of raising natural gas to 10 percent of the energy mix by 2020.

During the 2000s an effort was made to bring about a gradual price reform and to a certain extent this has helped the expansion of gas use in China. According to CNPC's analysis, during the period 2000–2009, China's natural gas consumption increased from 24.5 bcm to 88.7 bcm, with an annual growth rate of 15.4 percent. Annual average growth was 4.5 bcm during the period 2000–2005 and 10.5 bcm in 2005–2009. The share of natural gas in China's energy consumption mix increased from 2.4 percent in 2000 to 3.8 percent in 2009.

The two most important institutions in China's energy bureaucracy that supervised this unprecedented gas expansion were the State Council and the National Development and Reform Commission (NDRC), while the three NOCS – CNPC, SINOPEC and CNOOC – are the main vehicles for implementing the expansion. Like Gazprom in Russia, CNPC is exclusively authorised to handle the transnational pipeline development negotiations with both Russia and the Central Asian Republics – mainly Turkmenistan, Uzbekistan, and Kazakhstan. SINOPEC as the latecomer in the gas upstream business is increasing its presence in both the Sichuan and Tarim basins. In the case of offshore gas field developments and the LNG import business, CNOOC is at a real advantage. It is worth noting that the Ministry of Land and Resources is responsible for the current initiative for shale gas development in China. However, the gas expansion drive by the three NOCs was, is, and will be significantly affected by NDRC Price Department's stance towards the long delayed gas price reform.

Maximisation of Domestic Gas Production

Among the three Chinese NOCs, CNPC was the driving force behind the expansion of gas production in China during the 2000s. In July 2009 a prominent Chinese energy expert, Jia Chengzao, chairman of the Chinese Petroleum Society (CPS) gave a strong indication that China's gas production capacity will reach 250 bcm by 2030, and consequently China will have to import 150 bcm of gas in order to cover the 400 bcm/y gas demand in that year. Xinhua News Agency's 'China Natural Gas Report' pointed out that the country's gas development is driven by four key regions – the Tarim basin, the Sichuan basin, the Ordos basin and the South China Sea basin. At their peak, production in these regions will, respectively, reach 75–80 bcm, 55–65 bcm, 40–45 bcm and 40–50 bcm. The total could be in the range of 210–240 bcm. During the December 2011 World Petroleum Congress in Doha, PetroChina's vice president Ning Ning said China's gas production will reach 150 bcm by 2015, of which 43 bcm or 29 percent will come from unconventional gas production. He predicted that by 2030 the figure would be 250–300 bcm, of which 100–150 bcm will be from unconventional gas.

Beijing planners have high expectations for coalbed methane (CBM) and shale gas production. According to the National Energy Administration (NEA)'s CBM industry development plan for the 2011–2015 period, China's CBM is projected to reach 20–24 bcm by the end of 2015, of which 10–11 bcm from surface wells and 11–13 bcm from underground sources. This target figure was reconfirmed in NDRC's 12th Five Year Plan. The draft plan envisages 21.5–23.5 bcm/y production by 2015. In the case of shale gas, in March 2012 China officially unveiled shale gas production targets, with the NEA's 12th Five Year (2011–2015) Shale Gas Development Plan calling for output to reach 6.5 bcm/y by 2015 and between 60 and 100 bcm/y by 2020 (the initial projection was 80 bcm/y).

Western institutions are not as convinced about the rosy picture of the shale gas revolution in China during the 2010s. Wood Mackenzie projected that by 2020, China's CTG (coal to gas) and CBM production will reach 27 bcm and 17 bcm respectively against only 11 bcm of shale gas production. These projections suggest that China could fall considerably short of its shale gas production goals. Wood Mackenzie also predicted that CTG and CBM will each deliver more output than shale into the Chinese gas market right up to 2024, and added that shale gas development is a long-term story in China that will only accelerate after 2020 to provide a major boost to domestic gas output. By 2030, it could potentially contribute around 150 bcm. It remains to be seen whether this ambitious target can be achieved. The shortage of water supply in the northern part of China, however, will restrict shale gas production significantly.

Unprecedented Demand Growth

Despite the rapid rise of domestic capacity, the level of gas demand outpaced it. According to the CNPC, natural gas consumption in China recorded an annual growth of 16 percent during the 2000s, reaching 107 bcm, 4.4 times the use in 2000. It constituted 4.4 percent in the total use of primary energy, up from

2.4 percent in 2000. China's production during the 2000s recorded 14 percent annual growth, reaching 94.5 bcm in 2010, 3.6 times higher than in 2000. Demand in 2011 reached 130 bcm, with production at only 110 bcm.

In 2010, the NEA predicted that China would witness an unprecedented increase in gas use, and that demand in 2015 would reach 260 bcm, 8.3 percent of China's primary energy mix. Immediately after the 12th Five Year Plan (2011–2015) announcement, the Energy Research Institute (ERI) projected that China's natural gas supply by 2015 would be as high as 230–240 bcm/y, of which 150 bcm would be domestic production, 30 bcm imports in the form of LNG, and 50 bcm imports by pipeline. CNPC projected that demand in 2030 would reach 392 bcm. This figure is based on the reference scenario; under the high growth scenario the figure is 438 bcm, and under the low growth scenario, 341 bcm. Wood Mackenzie went so far as to state that total gas demand would rise from 93 bcm in 2009 to 444 bcm in 2030, a compound annual growth rate of 7.5 percent, most of the growth coming before 2020.

Against CNPC's 2010 projection of 392 bcm/y of gas demand by 2030, ERI and SINOPEC's 2011 projection easily passed the 400 bcm benchmark, reaching 430 bcm and 467 bcm respectively. A year later CNPC's projection reached 500.0 bcm for the first time. What is not clear at this stage is how large a contribution domestic production will make in China's gas expansion in the coming decades. During the World Gas Congress conference in Kuala Lumpur in early June 2012 Wood Mackenzie predicted that China's gas demand would increase from just over 150 bcm today to more than 600 bcm in 2030 – accounting for almost 30 percent of incremental global gas demand growth over that span. Even with unconventional gas growth, Wood Mackenzie added that China would still require over 130 bcm of uncontracted imports by 2030.

Uneven Distribution of the Gas

Despite massive gas expansion, the benefits will not be equally shared among provinces. Natural gas comprises 12 percent of Beijing Municipality's energy mix, the highest ratio of China's 31 regions. Shanghai ranks a distant second with natural gas forming 4.12 percent of the municipality's energy mix last year. In the prosperous economies of Tianjin Municipality and Guangdong Province gas accounts for approximately 3 percent of energy consumption. Several regions in west China, including Shaanxi, Shanxi, Qinghai and Gansu provinces as well as the Ningxia Hui Autonomous Region, boast higher proportions of natural gas in their energy mixes due to proximity to major gas production bases. Due in part to substantial newly discovered gas reserves, Sichuan Province boasts a higher ratio of gas utilisation than other Chinese regions at an estimated 2.71 percent.

According to CNPC, eastern China areas would see higher demand for natural gas than western areas, while more than 65 percent of the nation's total demand for natural gas would come from central and southern China by 2030. It also forecast that carbon dioxide emissions are to be reduced by 300 mt, 470 mt, and

"Beijing planners have high expectations for coalbed methane (CBM) and shale gas production."

67 mt respectively by 2015, 2020 and 2030, while sulphur dioxide emissions are to be reduced by 5.05 mt, 7.68 mt, and 10.97 mt assuming that all the natural gas consumed is used to substitute for coal. This projection confirms that the Beijing authority is serious about reducing pollution levels in China; and the short cut to dealing with the issue is to reduce the country's dependence on coal.

Table 1 shows the ERI's projection that gas demand by the power sector will reach 80 bcm/y by 2030, while the demand by city gas (town gas) will be only 70 bcm. However, the ERI projection is very different from that of the Chinese NOCs such as CNPC and SINOPEC, which envisaged a much greater demand by city gas in the coming decades.

Gas Import Options: Pipeline vs LNG

The figures of 500 bcm/y projected by CNPC and 600 bcm/y by Wood MacKenzie are very encouraging in terms of slowing down China's heavy dependence on coal use. A significant volume of pipeline gas and LNG would have to be imported to meet the demand. Beijing planners prefer to maximise pipeline gas imports as it does not require sea lane supply. However, Beijing's preference does not necessarily mean that the maximisation of pipeline gas imports in the coming decades will save the market for 68 bcm pipeline gas supply from Russia to China. China is already committed to import a total of 100 bcm/y of pipeline gas from the Central Asian Republics, of which 65 bcm/y from Turkmenistan, 25 bcm/y from Uzbekistan, and 10 bcm/y from Kazakhstan. In April 2011, NEA indicated that construction of the third, fourth and fifth West-to-East pipelines (WEP) will begin during the period 2011–2016. If the construction of WEP III, IV and V are completed by 2020, the maximum supply capacity will be 120 bcm/y (30 bcm/y x 4). As WEP II and III are already allocated for the

Table 1: ERI's Projection of China's Gas Demand by Sector (Unit : bcm)

	2010	2020	2030
Town gas	19.0	33.5	69.0
Service	8.5	16.9	35.0
Heating	6.0	13.2	26.0
CNG	4.0	14.3	27.0
Industry	35.0	98.0	147.33
Power Gen	23.0	71.2	80.13
Fertiliser	21.0	40.8	45.44
Sub-Total	116.5	287.9	429.9
Oil field's self use	5.0	5.9	7.5
Total	121.5	293.8	437.4

Source: Energy Research Institute, NDRC, China (2011) pipeline gas supply from the Central Asian Republics, the space for Altai gas from Russia's west Siberia can be identified only after WEP IV and V are completed. It remains to be seen whether an integrated package deal (based on cooperation in upstream, midstream and downstream sectors) offered by the Chinese side during the first half of 2012 will open the door to the pipeline gas supply from Russia to China during the second half of the 2010s.

Apart from the 110 bcm of pipeline gas (including that from Myanmar), China is determined to expand its LNG supply very rapidly. Until 2011, a total of five LNG terminals were in operation, and four more terminals are now under construction. The total LNG receiving capacity for the nine terminals will be around 30 mt/y (with the second stage development, it will be at least 50 mt). If the additional eight to ten proposals to build LNG terminals are approved by NDRC, the scale of LNG supply to China will be massive. Interestingly, Wood MacKenzie made a cautious projection on China's LNG expansion. In the mid-term, China's position is stronger than that of regional buyers like Japan and India, with LNG demand reaching only 18 bcm by 2017. Long-term LNG demand will accelerate, requiring an additional 33 bcm by 2020 and 50 bcm by 2030. Considering that Chinese NOCs are very sensitive about the price of imported LNG, price competitiveness will play a critical role in LNG expansion. In this context, Russia's Asia strategy to prioritise LNG export will be heavily affected by the price factor. One thing for certain is that the price of Vladivostok LNG based on the long distance pipeline gas supply from East Siberia will not be competitive.

In short, China is set to witness a massive gas expansion during the 2010s as Beijing is determined to increase the role of gas in China's energy balance. It remains to be seen whether China will be the beneficiary of the shale gas revolution. The result of unconventional gas development in China during the 2010s will balance the level of pipeline gas and LNG imports to China. One thing for sure is that China will not simply wait for the pipeline gas supply from Russia; if there is no breakthrough by the end of 2012 it will give maximum attention to alternative gas supply sources, in particular LNG. For this reason many western observers are very interested in understanding the role of Russia's pipeline gas in China's gas expansion in the coming decades. If the breakthrough is made in 2012, the impact on regional and global gas trading will not be small. ■

Gas in India: The Transition Challenge

ANIL JAIN reflects on India's growing reliance on natural gas imports

India is 70 percent import dependent for crude oil, but imported gas (LNG) accounts for just 28 percent of its total gas consumption. With the former comprising 30 percent of India's primary commercial energy supply against 11 percent of gas (*BP Statistical Review of World Energy, 2011*), it is evident that unlike oil, imported gas has not featured predominantly in the country's energy mix. There are several reasons for the limited role to date of natural gas imports on the Indian market – most prominently the difficulty of establishing a transnational gas pipeline and the absence of a long-term pricing policy in Indian gas user industries, which is necessary to support LNG supply contracts. Consequently, and in spite of the proximity of India to large gas deposits in the Gulf, the country is not an important player in the world gas market at present.

This is, however, set to change. In May 2012 an Indian government gas company (GAIL) and its counterpart in Turkmenistan, signed an agreement for the supply of gas through the overland TAPI gas pipeline. LNG imports are likely to treble in the next four years, with new contracts being signed up from Australian and US gas fields. These developments are a result of a conscious policy decision to encourage gas consumption in the country, including under the government's objective to help India diversify its energy supply sources.

The Supply Trigger

India's policy review that envisions a greater role for natural gas – both domestically produced and imported – was catalysed by a large exploratory success under a new E&P regime, the New Exploration Licensing Policy (NELP). The first major gas find under NELP came from the KG-D6 block, which supplied 63 million metric standard cubic metres per day (mmscm/d) of gas in 2010. With this, private production overtook NOC production, with the latter dropping from 70 percent of total production in 2007, to a little over 40 percent by 2009 (Jain, *Natural Gas in India*, 2011). The start of this new source of supply has been hailed as a significant development, because in addition to the environmental benefits of gas, it may help check India's rising oil import dependence.

The ramp up in domestic gas is being supported by activity on the LNG front as well. The first LNG receiving terminal went live in 2004, and total supplies have since risen to 12 mmtpa, which are likely to triple by 2016, thus significantly increasing its importance on the Indian market. The initial LNG purchase agreement was supported by back-to-back sale contracts for a limited volume with government fertiliser and power units. This deal notably succeeded despite including substantially higher prices for gas than charged by domestic Indian NOCs whose gas prices remain administered by government. The reasoning behind the agreement was that if the price of urea and power were to be kept low for the agriculture sector, the higher price for gas would have meant a higher subsidy outgo.

Domestic Policy Areas: Pricing and Gas Allocation

India's new domestic production by private companies and its new import deals, have triggered a series of policy changes. The first set consists in pricing policies. The earlier supplies of NOCs were priced by the government on a cost plus basis, allowing a normative post-tax rate of return. Under the subsidy policy of the government in the urea and power sectors, fuel (and feedstock) prices have historically been a pass-through in price fixation, with the final price being further discounted by grant of subsidy as well as cross-subsidisation from industrial and commercial consumers (in the power sector). However, the new source of gas coming from private sources could not be priced at a discount. After considerable debate, the KG-D6 gas was priced in 2007 at $4.20/mmBtu. This was a major departure from the existing gas pricing regime, wherein the NOCs were getting $1.79/mmBtu. The NELP price approval came as a boon for NOCs too, with the government approving $4.20/mmBtu for NOC gas in 2010.

The second set of changes is taking place in the subsidy policy. While so far both input and output subsidies have been in existence in fertiliser and power sectors, there is now a change. With a higher gas price, the government has had to shift the gas price burden entirely to the output stage. As it has not raised the retail price of urea, the enhanced subsidy is being financed entirely through the budgetary process. Total central government expenditure on subsidies to fertilisers in 2010–11 amounted to almost 1 percent of GDP (Jain, 2011,). An old recommendation of several government committees to make subsidies direct, has found acceptance due to the trigger of a higher gas price, and a shift away from input subsidy. Secondly, it is also notable that a higher gas price has meant a higher price for electricity, especially for traded power as opposed to base load supply, as well as for non-agricultural electricity users. Since urea is an important input in agriculture, its prices have been kept static however. The adoption of merit-based subsidy reflects a change in the overall subsidy policy outlook and is the second change in the subsidy policy. The acceptance of higher priced non-NOC gas (even LNG) in the urea and fertiliser sectors is evident from Table 1.

The third set of changes belongs to the broad category of gas allocation. Any scarce resource would naturally generate large demand, especially if the price is administratively fixed below what the market can bear. India has had a long history of prioritised gas allocation, which has strongly influenced planning and execution in the main gas-consuming sectors. The objectives of this system were (a) to 'manage' shortages in gas availability (b) provide gas at subsidised prices and (c) to play an integral part in the planning process. With stagnant domestic supply, which was allocated to prioritised consumers by the government, gas markets failed to evolve. Consequently, in the absence of a vibrant market mechanism, the new gas supply was distributed by the government as per a priority order. This allocation is quite different from the system that prevailed for NOC gas in the nineties, and while not entirely market friendly, is nevertheless, for the following reasons, an important step towards the evolution of free markets. The new gas has been allocated across all consumer categories – urea, power, city gas, refineries, steel and petrochemicals, and it is expected that enhanced supplies will lead to inclusion of yet more categories. Already, a liberal pipeline policy has been announced, wherein private sector investment has been allowed for the first time. Expanded pipeline infrastructure has, in turn, promoted new LNG terminals (as discussed earlier, supplies to rise substantially). The setting up of a Joint Venture by BP/Reliance Industries for gas marketing marks the arrival of big corporates in this business.

Table 1: Gas Consumption by Sector 2011 (mmscm/d)

Sector	NOC Gas	Private Gas	R-LNG	Total
Fertilisers	14.36	15.34	8.18	37.88
Power	22.75	33.41	4.26	60.42
Others	19.17	15.66	33.93	68.76
Total	56.28	64.41	46.37	167.06

Source: Ministry of Petroleum and Natural Gas, Government of India

The transition occurring in India's gas sector is part of the larger movement of the economy from a centrally planned and administered system to one based more on the operation of market principles. Situations of economic transition cannot be understood simply in terms of the conventional paradigm of demand and supply being brought into balance by prices. That is why, although the NELP PSC provides for marketing freedom, it also has provision for government's possible role in gas allocation, which was invoked when the new gas supply started. The gas producers from the KG-D6 fields, probably with a view to facilitate the transition of the gas market, themselves proposed a moderately high price for their supply, whereas the prices of imported gas supplies were ruling much higher. With the government-owned PSUs being the biggest consumers (especially in the fertiliser and power sectors), this has helped in re-aligning the pricing and subsidy policies, without a gas 'price shock'. Towards this end, the government announced a gas consumption priority order, which because of the gas price being kept uniform across the consuming sectors did not put the producers to any loss. While this new allocation system may not be market determined, it has nevertheless set the process in motion for the evolution of a diversified gas market.

Importance of this Change

India's annual per capita electricity consumption was 778 kWh in 2009, against world average of 2782 kWh in 2008 (Press Information Bureau, Government of India, 12 August 2011). An official Indian Government document (Integrated Energy Policy) acknowledges that 'energy security' is not only about supply, it also ought to come at affordable prices. The gas supply trigger, and the accompanying set of changes in pricing and growth of markets, may be the first step towards liberalising the entire energy sector. Not that there are no policy developments in the other energy sub-sectors, but the NELP gas success will perhaps have far-reaching effects in all fuel sectors. For example, although changes in coal policy are being driven by the opening up of power generation, production is still primarily in the hands of a government company with the coal being priced administratively. Therefore, even after reforms in the power sector, status quo exists on coal prices. Consequently, policy change in natural gas is the first bold attempt to price energy commercially. This is a tall order for a fuel that meets only 10 percent each of the primary energy demand of the country and power generation capacity by fuel. On a positive note, there is a re-think in the government on natural resources allocation policies and coal blocks are now set to be auctioned on a premium basis.

The recent exploratory successes in gas assume a lot of importance and could be the solution to the energy security problem of the country – not only in view of the country's continued import dependence for nearly-two thirds of its crude oil supply. Since only half the sedimentary area has been fully explored so far, if India were to step up investments in the oil and gas E&P, looking to NELP successes, there is the likelihood of vast hydrocarbon resources being found. A favourable pricing and market based allocation policy would be the pre-condition for the above happy event to happen. As of now, energy supply in India may be coming from diversified fuel sources, but the energy market is not well segmented by price. Hence, gas faces competition from other fuels, and a successful gas supply policy pre-supposes a dynamic overall energy policy, which this gas supply trigger may help usher in.

Resistance to Change

The interests of gas-consuming sectors should not normally be contrarian to those of gas producers. But, if there be a rent seeking paradigm, it would be difficult for anybody not to desire a share in it. The existing regime of administered pricing, subsidies and government-mandated allocations in many commodities, has created vested interests and lobbies, leading to resistance to change. It has also discouraged investors from taking an active interest in the country's natural resources, with the result that India is still importing coal while at the same time, oil and gas basins remain underexplored. Since domestic supplies are not rising, and imports come at market price, it is becoming increasingly difficult for the government to supply affordable energy to the common people.

"The current situation can be seen as a 'half way house' – a stage on the way to a fuller reform."

The change in gas policy is also being resisted by the urea and power sectors, which while being desirous of free pricing in their segments are nevertheless cautious when it comes to gas. It would be easier if there were a common demand to open up pricing along the entire value chain – at least, there would be no challenge to the economic rationale, and less interest groups to contend with.

In addition to stakeholder resistance, another difficulty is change management. An overhaul of the existing system needs the right policies, and acknowledgment of the fact that transition takes place over time, not over night. For pricing to be opened up, all the stakeholders, including the government have to make compromises. We have seen that higher fuel price means higher subsidy. Therefore, resistance to change is coming from both within and without.

Way Ahead

As discussed in the preceding paragraphs, gas policy in India is changing, albeit slowly. In 2007, when NELP gas supply was around the corner, the producers wanted market price, an entirely new concept for the country. But, in spite of resistance, policy makers went ahead and gave their approval. However, there is again fresh uncertainty on both the pricing of additional supplies, and the price revision of the earlier one due in 2014. There is also no long-term gas supply policy outlook. The government cannot go on allocating private gas. It can at best prioritise sectors, and let the market processes take over, while building safeguards to ensure that price discovery is not thwarted in this exercise. The crude price having risen from $65/barrel in 2007 (when the NELP gas price of $4.20/mmBtu was approved) to around $100/barrel presently, there is a huge demand for domestic gas, making allocation a sensitive subject. Therefore, while gas price needs to reflect present day market reality, supply priorities need a firm policy plank. The most vital issue is linking the price discovery with the consumers – given the fact that for many (urea and power), gas price is a pass-through. It remains to be seen what would be the price discovery process in the long run – who will comprise the universe from where the future gas prices will be discovered.

The current situation can be seen as a 'half way house' – a stage on the way to a fuller reform. The good news is there is realisation in the government that competitive markets can help bring more investment into E&P, and LNG infrastructure. Natural gas is now, constitutionally and popularly, regarded as part of the whole country's inherited wealth. That might encourage the thought that it should be fully brought into production and used in such a way that it diminishes other less desirable parts of the country's heritage – underdevelopment and inequality.

Note: This article reflects the views of the author and does not in any way convey the official view of the Government of India.

Building the Case for a Trans-Afghan Gas Corridor

DANILA BOCHKAREV argues India's and Pakistan's energy security might soon depend on the Trans-Afghan Gas Corridor

Natural gas has a potential to gain importance in India and Pakistan as a key component of the energy mix, particularly in the power sector. Gas is already playing a major role in Pakistan's energy sector and is rapidly gaining market share in India. For example, Pakistan has the region's highest per capita natural gas consumption with the notable exceptions of gas-rich Iran and Turkmenistan.

Natural gas can provide a quick solution to the energy/power deficit in both India and Pakistan, emerging as a regional energy 'game changer'. In the case of Pakistan the role of gas can be complemented by the import of a surplus of cheap hydropower electricity from Tajikistan and Kyrgyzstan. Hydropower can in principle play a significant role in ensuring energy security, but planning and construction of hydropower installations are very time consuming and often carry considerable economic, political and social costs: dams can disrupt water basin balance, remove water from the agricultural sector and complicate relations between upstream and downstream countries. Nuclear power stations are also expensive to build and create a number of safety and security risks, linked to their working cycle and utilisation of spent fuel. 'Green' electricity produced from wind and solar could theoretically be competitive if compared to diesel-based generators. However its share in the regional energy mix to date is low and renewables are virtually nonexistent in Pakistan and relatively unimportant in India. Renewable energy sources like solar and wind, therefore, will not be able to address the deficits in Pakistan and India anytime soon. They are also costly investments, requiring special electricity grids and backup power generation capacity.

Energy deficit is a very serious challenge both for New Delhi and Islamabad. Estimates of the Planning Commission of Pakistan suggest that losses arising from electricity and natural gas shortages held down GDP growth by 3–4 percent in 2011/2012. Insufficient exploration, inefficient policy regulations and lack of conventional gas resources led to stagnation of domestic gas production and consumption in Pakistan. For instance, in 2011 gas production decreased by 1.2 percent to 39.2 billion cubic metres (bcm). The lack of gas supplies is particularly harmful to Pakistan's electricity sector where the gas deficit led to more intensive usage of costly fuel oil in thermal power stations, increasing the cost of electricity by 40 percent. Until recently consumption of natural gas has been growing rapidly, mostly driven by cheap domestically produced gas sold under regulated prices. The access to natural gas both at home and abroad is clearly becoming a crucial challenge for the country and its electricity sector. The absence of progress in hydropower generation and coal mining further emphasises the importance of access to new supplies of natural gas.

Despite a number of impressive 'success stories', India is facing similar challenges. The Economic Survey of India 2011–2012 estimated that power shortages represented a loss of US$3.4 billion in generational capacity, which is equal to a US$68 billion annual decrease in GDP growth. This number represented 4 percent of India's $1.727 trillion nominal GDP. India is also experiencing growing difficulties in securing an adequate growth of gas supplies, which is starting to limit natural gas consumption, especially in the power sector. From January to April 2011, gas usage in India's thermal power generation plants decreased by 4 percent together with expensive diesel generation (-13.07 percent), while overall thermal power generation grew by 166.5 percent. Increasing primary energy and electricity consumption, insufficient domestic production and an unwillingness to import excessive amounts of expensive LNG seem to put India in the same boat as Pakistan regarding the urgent need to find new sources of (imported) gas.

The Iranian and Qatari Supply Options

There is clearly no shortage of gas in the region due to the geographical proximity of Iran, Qatar and Turkmenistan with respectively 33.2 trillion cubic metres (tcm), 25 tcm and 24.3 tcm of natural gas reserves. However, reality is shaped by obstacles other than the advantages of geography. For example, although Iran is theoretically able to cover most of Pakistan's and India's gas imports, international sanctions have prevented it from expanding its capacity. Even if sanctions against Iran were removed, it might take the country between five and ten years to increase substantially its gas exports. There has been an absence of sufficient investment in the Iranian energy sector for too many years. The gap between natural gas consumption and production even appears to be growing: production of natural gas in Iran grew in 2011 by 3.9 percent to 151.8 bcm, while consumption increased by 6.1 percent to 153.3 bcm. In 2011, Iran, the country with the world's second largest reserves, had to import natural gas! These issues are likely to heavily affect the ability even of a post-sanctions Iran to immediately export sufficient amounts of natural gas to India and Pakistan.

Qatar could be a major supplier as well. In 2011, India bought 13 bcm of Qatari gas and is in principle eager to further increase LNG supplies from this country. Doha might be willing to sell more gas to

"In 2011, Iran, the country with the world's second largest reserves, had to import natural gas!"

New Delhi but at a high price, and India will have to compete with East Asian buyers, accustomed to the Asian LNG prices. There is a cap of $500–520 per 1000 cubic metres (mcm) of gas that India might be able to pay, yet prices of Qatari LNG often reach $600–700 per mcm. Furthermore, even a $500 ceiling is rather high if compared to an estimated price for Turkmen gas imports (400–450 per 1000 cm depending on the price of Brent). That makes Qatar only a secondary (yet still important) source of additional supplies for India.

Pakistan has also shown an interest in gas imports from Qatar. According to a Memorandum of Understanding signed in February 2012, Pakistan was planning to import up to 5.1 bcm/year of Qatari natural gas. However, it is likely to cancel the deal due to the high price ($630 per mcm) asked by Qatar. Doha's decision to charge an excessively high price is possibly explained by a number of setbacks and problems, including political favoritism. On 3 November 2011, *Interfax* reported that Islamabad initially awarded French energy company GDF Suez a contract in February 2010 to supply up to 5.2 bcm / year to the planned LNG terminal at Port Qasim next to Karachi. The Supreme Court of Pakistan however canceled the agreement in April of the same year, claiming that the Ministry of Petroleum & Natural Resources had bypassed a lower bid by the Fauji Foundation, an investment group run by former Pakistani military officers, and energy trader Vitol.

Turkmenistan as the most likely Option

In the 'absence' of Iran and Qatar, Turkmenistan is likely to become the best available option. This country with up to 24.3 trillion cubic metres (tcm) of gas reserves can provide enough gas to India and Pakistan via the TAPI pipeline at a relatively affordable price. Turkmenistan, courted by numerous clients, has already a vast choice of export options. According to *BP Statistical Review of World Energy* in 2011 exports to Russia reached 10.1 bcm, to Iran – 10.2 bcm and to China – 15.5 bcm. Turkmenistan has enough gas to supply all of its existing and potential clients, including India and Pakistan. Even back in the late 1980s, Turkmenistan was already producing up to 90 bcm, exploiting at the time a smaller natural gas resource base. However additional export volumes are conditional upon Turkmenistan's ability to develop its resources at the right time.

Furthermore, potential gas supplies from this country are affected by a number of important challenges. Firstly, the security situation in Afghanistan has been complicating and de facto preventing the realisation of the TAPI pipeline and CASA–1000 electricity network. China's relationship with Turkmenistan as a major consumer of the country's gas is the second important factor affecting the regional energy landscape, in particular a trans-Afghan energy corridor. Beijing is already the second largest importer of Central Asian gas and will soon overtake Moscow – currently the largest buyer. In 2011 almost 50 percent of China's natural gas imports came from Turkmenistan. Beijing plans to further increase the imports from 15.5 bcm in 2011 to 65 bcm post 2015. The IEA estimates that China's gas imports will reach 109 bcm by 2017. Central Asia's supplies, predominantly from Turkmenistan, will therefore account for at least 60 percent of China's natural gas imports.

Chinese imports of 65 bcm as of 2015, continued Russian and Iranian purchases of a combined minimum average of 30 bcm/year by 2014–2015, and Turkmenistan domestic consumption (20 bcm/year) might result in a situation where not enough Turkmen gas for the TAPI gas pipeline will be available unless new production capacities are brought upstream. It still remains to be seen if Turkmenistan is capable of increasing its production capacity above the ceiling of 110 bcm per year in the period of 2015–2018. Though Beijing never publicly voiced concerns regarding the TAPI gas pipeline, one can assume that China is not too eager to share its access to Turkmenistan's gas supplies unless it can be confident that they are adequate to meet its own rapidly growing demand.

Thirdly, the transit of energy via Afghanistan will require a multitude of important regulatory and investment decisions. It would be helpful to rely for those decisions on already established and internationally accepted energy transit regulations and mechanisms for investment protection. In this context, energy transit and trade could in principle play a constructive role and act as a catalyst for more efficient regional cooperation between Central and South Asian countries, if the aforementioned challenges are resolved. Due to its major importance it might even re-create the positive spillover effect of the European Coal and Steel Agreement (1951), and improve the frequently rocky political relations between India and Pakistan. Both Islamabad and New Delhi therefore have a strong common interest in ensuring reliable gas supplies from Central Asia.

Current energy planning in the region however depends heavily on China's vested interests as a major consumer of Turkmen gas. India and Pakistan standing in comparison at the 'end of the queue' might consider a joint consultative process with Turkmenistan, China and other consumers of Turkmen gas regarding allocation and timely development of the gas reserves. It could be achieved through an international consortium, helping Turkmenistan to increase its gas production. This consortium should have an open membership, conditional upon the approval of the Turkmenistan authorities.

The construction of TAPI and CASA–1000 and the transit of gas and electricity via Afghanistan will require a multitude of important regulatory and investment decisions. It would be helpful to rely for those decisions on already established and internationally accepted energy transit regulations and mechanisms for investment protection. The Energy Charter Treaty (ECT) could become an appropriate 'umbrella' providing for such regional 'rules of the game'. One might argue that multilateral institutions already present in the region should instead be used to facilitate the implementation of TAPI and CASA–1000 projects. However the South Asia Association for Regional Cooperation (SAARC), the Economic Cooperation Organization (ECO) or the Regional Economic Cooperation Conference on Afghanistan (RECCA) all largely fail to give sufficient attention to the complicated and diverse energy landscape in the region, primarily due to the lack of accepted legally-binding instruments, relevant policy mechanisms and their limited geographical scope. The World Bank's Central Asia Regional Economic Cooperation Program (CAREC) does have a geographically relevant membership and scope of action. However, it does not deal directly with energy governance or energy cooperation issues.

The importance of the ECT appears greater in Southwest Asia than in Europe, for which it was originally created, due to the region's poor record of genuine multilateral cooperation and bilateral relationships often shaped by profound mistrust. Potential gas and electricity suppliers such as Turkmenistan, Tajikistan and Kyrgyzstan are already full members of the ECT. Afghanistan, India and Pakistan should consider becoming full members of the Energy Charter Treaty as well. That would put TAPI and CASA in a homogeneous legal and regulatory framework and facilitate uninterrupted flows of energy via Afghanistan. ■

The views expressed in this article are those of the author and are not necessarily shared by the EastWest Institute, its board of directors or other staff.

East African Gas finds a Probable 'Game-changer' for the Region

JON MARKS explains why the global gas industry should look at East Africa

The East African coast, stretching from Somalia, down past Kenya and Tanzania to Mozambique was long thought to be a region of Africa that, while rich in minerals, was of little interest to international oil companies (IOCs). On the rare occasions that drilling had taken place in this vast and diverse region, it had too often failed; prolific oil seeps had failed to reveal commercially exploitable fields. And when potentially commercial fields had been found, for

example in Somalia, political crises had intervened to send IOCs declaring force majeure, or at least persuading them not to renew their permits.

Exploration off Somalia in the 1960s and 70s had identified potential hydrocarbons plays, with analogies to Yemen across the Gulf of Aden. To the south, South Africa's Sasol in the 1990s had developed two gas fields offshore Mozambique, Pande and Temane, which fed its prime market, Johannesburg and the wider Gauteng area, via a pipeline to Sasolburg. Off Tanzania the Songo Songo gas field was developed by upstream operator PanAfrican Energy (Orca Exploration) and the UK government-owned power developer Globaleq, in order to supply gas for power and industrial consumers in the Dar Es Salam region. Songo Songo was an important project which proved that, if the economics were right, domestic gas sources could be tapped to generate electricity and provide feedstock for local industrial growth – a fact that might be commonplace in many markets, but which has proved hugely elusive in sub-Saharan Africa (SSA). But with oil finds proving elusive across the under-explored region, there was none of the associated gas available that has fed into natural gas export schemes in Nigeria, and more recently Equatorial Guinea and Angola on the west coast.

This situation has changed radically with major natural gas finds off Tanzania and Mozambique, which will have far-reaching consequences for both economies. In a paper to a 28 September 2011 seminar on Next Generation Markets, organised by JP Morgan in Washington this author concluded that the indications that had so far leaked out from IOCs involved in the early stages of exploration pointed to at least one LNG train being possible in Tanzania and another in Mozambique, and that such developments would have a 'game-changing' impact on both economies. This view (unusually bullish for the author) was met with some scepticism among observers and past investors in the region. However, by time of writing, both Tanzania and Mozambique had become established in investors' minds as gas plays with a major future.

The extent that the East African finds can be considered game-changers has yet to become clear, but it seems probable that in the next decade both Mozambique and Tanzania will host LNG export projects – and may, indeed, co-operate in gas gathering in some cases. They will benefit in this from being close to some very attractive markets. For example, these reserves are close to the wealthy Gulf markets, where demand for gas to fuel power supply is rising sharply. Royal Dutch Shell has developed a lucrative trade by establishing floating regasification plants in Bahrain, Dubai and Kuwait, supplied from Australia – pointing to the demand from this source.

And if looking east wasn't enough for the east coast's nascent natural gas industries, South Africa has an urgent need for more power. Some thoughtful players in the South African markets – for example the project financier Clive Ferreira, of Fieldstone Capital – are arguing for government strategists to think more about the potential for tapping Mozambican gas, rather than focusing on polluting coal, and costly renewables and nuclear power options.

Tanzania has Become a Gas Frontier

The Ministry of Energy and Minerals in June announced that recent gas discoveries had raised Tanzania's recoverable reserves estimate to 28.74 tcf, from 10 tcf only a few months before, due to a string of significant offshore discoveries in permits operated by BG Group – which operates offshore blocks 1, 3 and 4 – and Statoil, which operates Block 2 with a 65 percent stake alongside ExxonMobil, with 35 percent.

In June Statoil announced a second large gas discovery in offshore Block 2, where the Lavani well produced a preliminary resource estimate of 3 tcf of gas in place. In a statement announcing the find, Statoil executive vice president for exploration Tim Dodson was able to give a very upbeat report: 'We are also pleased to announce that the recently drilled Zafarani sidetrack added another 1 tcf of gas in place. This is in addition to the up to 5 tcf announced in February [from the Zafarani well]. The results so far mark an important step towards a possible natural gas development in Tanzania.'

What must follow is further exploration work – a range of sources consulted by the author observed that the geology suggests the region contains a series of fields, rather than one mega-structure (apparent off Mozambique) – and a series of probably complex negotiations with the government, which has yet to draw up a gas master plan. Already, as Tanzania's gas finds mount up, there is increasing confusion over infrastructure development.

Thus plans to expand capacity at the Songas processing plant, which has established an impressive track record, are on hold as the government pushes a Chinese-funded $1.2 bn scheme for a new pipeline from Mtwara to Dar es Salaam, to connect to the existing Songas pipeline. The Chinese pipeline, first mooted in 2011, has been promoted with the availability of cheap financing and high-level support, which have made it a government priority; Songas had lined up financing for its expansion, to provide more gas for a domestic power scheme, but this is now unlikely to go ahead as the Energy Ministry examines other options. Different voices in Tanzania have disparate ideas as to how the gas should be used. Tanzanian officials and IOCs agree that there will be a problem in managing expectations, amid excited talk that its gas finds have made the country a 'new Qatar'.

Eni's Mozambique Play

As highlighted by the bidding war for Cove Energy, a London Stock Exchange-quoted minnow with minority stakes in Tanzania and Mozambique, investors have become excited by prospects for the region.

Gas finds on the Mozambican side of the Rovuma Basin (shared with Tanzania) have been dramatic. For example a discovery of at least 10 tcf, announced in late March 2010 by major player Eni, was made in the Mamba North East-1 well (offshore Area 4). The Eni statement said that 8 tcf of this was 'contained in reservoirs exclusively located in Area 4'. Other finds in the Mamba Complex are located near the border with the Anadarko Petroleum Corporation-operated Area 1. Following these well results, Eni updated its estimate of potential gas-in-place to at least 40 tcf, taking Mozambique's Rovuma Basin offshore finds up to a possible 70 tcf. Even larger figures are believed likely. Even before the more recent data, in December 2011, Anadarko's international gas business development manager Brad Defenbaugh suggested that Mozambique could become the third largest exporter of LNG, behind Australia and Qatar. Anadarko is looking at a two-train LNG export facility with an FID scheduled in 2013 for first production in 2018.

The signals from Eni are that Mozambique is a major play that will help it to reduce its dependence on operations in other parts of Africa (notably, the north). This helps to explain why the Italian major's chairman, Paolo Scaroni, has personally led negotiations in Mozambique, where he has said that the finds could launch a '$50 bn investment'. Eni's options are headed by an Asian LNG play – there will undoubtedly be sufficient gas to supply local power and industrial projects, to help meet Mozambique's development agenda, and to supply export LNG trains. During a November visit, Scaroni was quoted as saying that Eni would employ 40,000 people at a new facility in northern Mozambique: 'We have to build a new town, and we discussed the location with [President Armando Guebuza]… It has to be near the discovery, but we all have to agree on where.'

Mozambique has big plans for its gas – but these do not seem especially divergent from Eni's own ideas. When Minister of Mineral Resources Esperanca Bias visited Japan in February for five days of talks, she said that Mozambique hoped to export LNG to Japan from 2018 and that some $50 bn would be invested over the next decade. Eni seems to have made common cause on this, while also agreeing to provide gas to feed local industry and electricity generators.

South Africa is another potential market for Mozambique's gas. It also has ambitions of its own. Forest Oil signed South Africa's first offshore production right to be granted to a foreign company in August 2009, and plans to bring ashore gas from the Ibhubesi field to supply a 750 MW combined cycle gas turbine plant. Development of Ibhubesi would open up the whole Orange Basin, which the Petroleum Agency of South Africa estimates could hold 25 tcf of gas. Shell has an application for a deep-water block west of Forest's, and eventually a pipeline could be built along the west coast to supply the Saldanha and Atlantis industrial developments.

West Coast Projects

Led by Nigeria, the west coast has been sub-Saharan Africa's leader in developing natural gas industries. More trains are planned in Nigeria – including Nigeria Liquefied Natural Gas (NLNG) train seven, and the Brass LNG and OK LNG schemes – but progress has been slow, with the National Assembly debating an elusive new Petroleum Industry Bill over the last several years.

Several other schemes have also taken years to come to fruition, including Equatorial Guinea Liquefied Natural Gas (EGLNG) train two – which would probably require importing some feedstock, from Cameroon and/or Nigeria, a daunting prospect given regional realpolitik – and Namibia's Kudu development, which has long been mooted as supplier to an estimated 800 MW power station to supply Namibia and South Africa.

While the nascent East African industry faces towards Asian markets, the Gulf of Guinea LNG industry's plans have been upset by the development of shale gas in the United States, which has brought about a global cooling of the Atlantic Basin LNG market.

One project that has made progress is the 5.2 mt/yr Angola Liquefied Natural Gas (ALNG) plant at Soyo, gathering gas from Angola's dynamic offshore oil industry. ALNG was expected to load its first cargo from Soyo as this article went to press, to be delivered by ALNG's first gas carrier, the Sonangol Sambizanga. Europe and Asia are the key markets in the wake of the North American 'shale gas revolution'. Initial cargoes – likely to number 74 a year – will probably go to Asia, although trades with European utilities are also expected. On 24 May 2012, the European Commission authorised the proposed acquisition of joint control of ALNG by its partners – Chevron (36.4 percent), state company Sonangol (22.8 percent), and BP, Eni and Total (13.6 per-cent each) – opening the way for Angola to export to Europe. In the same month, Petroleum Minister José Maria Botelho de Vasconcelos signed a memorandum of understanding with Thailand, which included the potential to import LNG.

Angola is assessing the prospects for further gas-related developments, including gas-to-power projects. However, Vasconcelos told a recent interviewer that 'we don't know all of our gas reserves', and observed that feedstock for the ALNG project was associated gas from oil developments rather than from 'pure' non-associated developments, which might be identified at a later stage.

Indeed, ALNG is a triumph for protracted efforts to tackle flaring by the offshore industry. Nigeria – a major offender when it comes to flaring – must also improve its gas-gathering to provide fuel for planned gas-to-power schemes and maintain export levels. More projects can thus be expected to emerge from the African west coast's major gas plays, while across the continent governments are looking again at the options for using gas as a domestic feedstock – a trend that will accelerate as gas prices delink from oil and fall as a consequence. But for the global-scale gas story in sub-Saharan Africa it is a case, for the first time in the industry's history, of looking east. ■

MENA is Confirming its Status as a Growing Gas Demand Centre

HAKIM DARBOUCHE challenges traditional views that see MENA as a future gas supply centre

In 2011, gas demand in the Middle East and North Africa (MENA) grew faster than in any other region in the world. It increased by almost 9 percent year-on-year, reaching just under 490 bcm. This is in line with the trend seen in the region since the early 2000s, particularly in the energy-rich Gulf countries as well as in Egypt, where gas consumption has been growing at an average annual rate of 7–10 percent. With overall gas demand growth not expected to show any signs of abating in the medium term, MENA's interaction with international gas markets to 2020 is more likely to be as a growing demand (and import) centre than as a major source of new exports, challenging the assumptions

seen hitherto in the trade-flow projections of major international organisations.

Demand for gas in the MENA region has been driven primarily by its expanding needs for power (8–10 percent per annum), which in turn have been fuelled by relatively rapid economic, demographic and urbanisation growth in most countries in the region. In some cases, particularly in the Gulf countries, large, government-led investment in the energy-intensive industries, such as petrochemicals, has also contributed to growing demand for feed gas, especially where the competitiveness of these industries is designed around the availability of subsidised energy input.

However, economic fundamentals alone do not tell the whole story. End-user gas (and power) prices are kept at artificially low levels by government policies in the majority of MENA countries, leading to inflated demand and distorted resource allocation. At $0.75/mmBtu in Saudi Arabia, $0.8/mmBtu in Kuwait, $1/mmBtu in Qatar and the UAE, $0.6/mmBtu in Algeria and $1.25–3/mmBtu in Egypt, domestic gas prices in MENA are well below opportunity values, and indeed below the marginal cost of new supply in many instances. They are the result of energy pricing policies that are rooted in a political economy logic that is no longer compatible with gas market and socio-economic realities in the region. Yet, governments find themselves locked in this logic and unable to introduce reforms without having to pay a non-material price for the required adjustments.

Data for 2011 also shows that MENA gas supply increased by more than 8 percent compared to the year before, but that did not translate into a higher share of the region's contribution to global gas exports, which remained unchanged at around 21–22 percent (Table 1). Among the region's gas exporters, only Qatar and Yemen saw relatively significant increases in gas production, driven by the ramp up of their LNG sales through the newly built liquefaction capacity. The rest of the growth was concentrated in associated-gas producers Saudi Arabia and Kuwait which, as well as having increased their oil production to compensate for the Libyan supply outage, began to see the results of the recent shift in their upstream gas strategies towards the development of non-associated reserves. Algeria and Egypt, the region's second and third largest gas exporters respectively, saw their production stagnate at best, with as a result a continued decline in exports.

Overall, MENA's gas supply potential remains under-exploited owing to a combination of low domestic gas prices, unattractive fiscal terms, and heavily bureaucratised sector management. But with growing gas shortages, many countries are looking to intensify E&P activity and attract more foreign investment by tackling one or more of the relevant issues faced by their upstream gas sectors.

Algeria: Moving to Unconventional Gas

Algeria's gas exports have been on a declining trend over the last few years, falling from over 60 bcm in 2006 to just over 50 bcm in 2011. This is mainly the result of stalling production, which reflects the beginning of the depletion of the giant Hassi R'Mel field – the lynchpin of Algeria's gas industry for five decades – and the fact that no major discoveries have been made and developed in several years.

To replace Hassi R'Mel with long-term reserves Algeria has little choice but to tap into its unconventional gas potential. Estimates of shale gas resources alone vary between several hundred to several thousand tcf, with the EIA putting technically recoverable reserves at 231 tcf. To this end, the government is in the process of introducing amendments to the hydrocarbons law, introducing greater fiscal incentives for unconventional gas exploration, and Sonatrach is partnering with selected IOCs, starting with ENI and Statoil. However, quite apart from the obvious logistical challenges involved in shale gas exploration, there is still uncertainty about the ability of Sonatrach to attract the required technology under the 51/49 percent shareholding arrangement.

With shale gas being very much a long-term prospect, Algeria will continue to struggle maintaining current export levels and market share in Europe, at least until the second half of the 2010s when the new Southwest fields will come on stream. The new LNG production capacity (9.2 mtpa) that will come online in 2013–14 at Skikda and Arzew will mostly serve to replace existing trains, which are likely to be retired by the end of the decade. In the longer term, Sonatrach will likely focus on pipeline exports where both its competitive advantage and netback values are greatest.

Libya: Continued Focus on Oil

Libya has never been a major gas province and will continue to be a relatively small exporter of gas until at least the end of this decade. The focus, should the political and security situation allow, will be primarily on oil, and the new government has promised to improve the investment terms it inherited from the previous regime.

Shell's decision to relinquish its upstream gas interests in Libya has come as no surprise, considering the disappointing results of its exploration activities in the Sirte Basin and the fact that the company is keen on limiting its exposure to the multitude of uncertainties in the new Libya. However, should better conditions become available there is little doubt that

Table 1: MENA Gas Data, 2001–2011

	Production (Bcm)	Consumption (Bcm)	Share of int'l trade (%)
2001	362.4	263	16.1
2002	379	276	16
2003	407	289	16.1
2004	445	313	15.9
2005	483	348	17.6
2006	514.2	362	19.2
2007	540.6	377	19.4
2008	570	412	20.6
2009	571	428	19.8
2010	622	448	21.4
2011	673	488	21.7

Sources: BP and Cedigaz

foreign investors will show renewed interest in Libya's undisputed conventional and unconventional gas potential.

Egypt: No More Pipeline Exports?

Like Algeria, Egypt's gas exports have been declining steadily for the last five years. Stagnating production and fast-expanding domestic demand have resulted in an acute gas deficit that has left the power and industrial sectors deprived of vital feedstock. With the removal of the Mubarak government last year, opposition to gas exports – particularly to Israel – grew, forcing the government to review pricing arrangements with Jordan for Arab-Gas-Pipeline (AGP) deliveries and with LNG offtakers BG, GDF Suez and Union Fenosa. The deal with East Mediterranean Gas, the owner and operator of the pipeline to Israel, proved just too controversial to handle, and the Egyptian gas holding company EGAS seized the opportunity to unilaterally terminate the 15-year supply contract binding Egypt to Israel. It would appear that in addition to political and commercial considerations, gas supply availability played a big part in EGAS's decision.

Until 2015 at the earliest, Egypt's gas supply-demand balance will remain very tight, squeezing LNG exports and undermining the viability of AGP supplies to Jordan, especially if the latter develops alternative import options. From 2015, new gas fields in the offshore Mediterranean are expected to come on stream, including BP's North Alexandria and West Mediterranean Deepwater concessions, but future supply will mostly be earmarked for domestic use as demand for gas in Egypt is expected to grow at no less than 6 percent per annum for the rest of the decade. Domestic gas prices remain a major issue, not only driving strong demand growth but also undermining the economics of new upstream gas projects. Unless the Egyptian government is able to offer higher prices to upstream producers or allow them to sell their gas directly to industrial end-users, EGAS's ongoing bidding round, where 15 gas prone blocks are on offer, risks falling flat. But with the political transition proving more protracted and complicated than anticipated, more uncertainty could be brought to bear on Egypt's gas sector.

Qatar: From Export to Domestic Focus

Having achieved its 77 mtpa LNG production capacity target, Qatar is now focusing on landing as many long-term contracts in the highest-paying markets as possible. With changing conditions in all three markets (North America, Europe, and Asia), this has meant showing more flexibility on its pricing policy.

Supply from the super-giant North Field for new gas export projects remains suspended until at least 2014 when the ongoing study of the reservoir is expected to be completed. Until then, any new reserves will be used on the domestic market to supply Qatar's ambitious plans for industrial and economic diversification. And beyond 2014, depending on the results of the North Field study, as much as 12 mtpa of liquefaction capacity could be added by debottlenecking the mega trains or, alternatively, regional pipeline exports could be increased if pricing issues with neighbours are resolved. Whichever way things go, Qatar is the only country in the MENA region capable of increasing its exports significantly by 2020.

Saudi Arabia: Gas Focus Paying off

Fears about the prospect of Saudi Arabia's rapidly growing domestic energy needs eating into the kingdom's oil export capacity came to a head in 2011. With reports that as much as 600,000 barrels per day of crude oil were being burnt for power generation, as imports of gas are not allowed, doubts were raised about the spare capacity available to Saudi Arabia and its ability to play the role of swing producer in future.

As the initial results of the Empty Quarter exploration campaign proved disappointing, Saudi Aramco's attention turned more recently to offshore reserves, fast-tracking the development of the Karan, Hasbah and Arabiyah fields which have a combined production capacity of some 4.3 bcf/d. Karan was brought online in 2011 and is expected to reach its 1.8 bcf/d plateau by end-2012, while the other two fields are expected to come on stream in 2014. As a result, Saudi Arabia's gas production hit 9.88 bcf/d in 2011, increasing by over 13 percent on the year before, and is likely to continue growing in coming years as new reserves are developed in existing exploration areas and in the deep offshore Red Sea. The only uncertainty concerns domestic gas prices as plans to increase them to a level that would improve the commerciality of non-associated reserves appear to have been shelved for now.

Kuwait: LNG Needs Firming up

Kuwait led the way by becoming the first country in the MENA region to begin importing LNG in 2009. Since then, its demand for gas (and LNG imports) has been growing rapidly, to the extent that an onshore LNG import terminal for year-round supplies is now under consideration. Such a terminal will certainly be needed if Kuwait's plans to develop tight gas reserves with the help of Shell continue to stall because of technical and political difficulties.

"only Qatar and Yemen saw relatively significant increases in gas production."

UAE: A 'sour' gas deficit

The UAE is estimated to have a gas deficit of some 10 bcm/yr and growing. While Dubai began importing LNG in late 2010, at a rate of some 1 million tons in the first year, Abu Dhabi's gas supply policy focused on the development of 'sour' gas reserves through the 2 bcf/d Shah and Integrated Gas Development projects. However, the 2014 start-up target for both projects looks increasingly uncertain, with technical difficulties compounding the commercial challenges besetting both projects. In the face of such delays and in the absence of any realistic prospect of receiving more gas from Qatar through the Dolphin pipeline under the current commercial and political conditions, the Abu Dhabi authorities are now looking into the possibility of importing LNG from 2014, starting with a 4 mtpa temporary floating facility and moving onto a more permanent option later on this decade.

Bahrain and Oman: Future LNG Importers?

Like other GCC countries, Bahrain and Oman are facing a gas shortage owing to limitations on domestic supply and growing demand. Bahrain seems to have decided to go down the LNG import route, having invited bids earlier this year for the import of LNG equivalent to 400–800 mmcf/d for 15 years starting in 2014, and even increased domestic gas prices by 50 percent to $2.25/mmBtu in January 2012 in anticipation of that eventuality. Oman, however, is exploring tight gas reserves, with BP developing the 1 bcf/d Block 61 project, and hoping that this would prevent it from having to resort to further imports of gas to be able to satisfy its domestic needs and firm LNG export commitments. BP's final investment decision is due in 2013 and will to a large extent depend on the ability of the Oman government to pay a higher price for the gas.

Iran: A Subsidy Reform Test-case

Iran is the only energy-rich country in the MENA region to have introduced a comprehensive energy subsidy reform and with some degree of success so far. Within the first year of the implementation of this programme, which began in December 2010, gas prices increased from as low as $0.30 to more than $3/mmBtu for residential users and up to $2/mmBtu for power generators and industrial users. The impact of these price hikes on demand has yet to be fully assessed, but it would appear the gas demand growth was slower in 2011 than in previous years, translating prima facie into higher exports to Turkey. On the supply side, the various phases of South Pars' development continue to move forward, though with a great deal of difficulty in the face of the debilitating effect of the international sanctions to which Iran is subjected. By the end of the decade, Iran's pipeline exports may increase, notably with the start of shipments to Pakistan in 2014–15, but LNG exports remain a distant prospect, especially if no changes to the political situation take place.

"Iran is the only energy-rich country in the MENA region to have introduced a comprehensive energy subsidy reform."

Iraq: An Unlikely Exporter Before 2020?

Much hope was pinned on Iraq as a potential source of gas for Europe's Nabucco pipeline, but domestic energy needs, project delays, and political wrangling between Baghdad and Irbil have all but dampened those expectations. Bar an improvement in the internal political and security situation and/or an agreement between the central government and the KRG authorities allowing gas from the Kurdistan region to be exported to Turkey, it is highly unlikely that Iraq will be in a position to export any significant amount of gas by 2020.

Conclusion

Gas demand growth in the MENA region will almost certainly be as strong in the years to 2020 as it has been since the early 2000s. With a few notable exceptions, this will put a dent on the export ambitions of countries in the region and force many of them to import gas should they (continue to) fail to sufficiently develop domestic resources. In the face of the resulting and increasingly generalised gas deficit, MENA countries will have few options but to deal with the issues that have contributed to this status quo, starting for some of them with improving the fiscal terms for foreign investment in gas E&P, while for many others it will be more a question of increasing domestic end-user prices from their current artificially-low levels to at least the marginal cost of production. Action on the domestic pricing issue will be led by the countries that are most gas- and cash-short (Egypt, Oman, Bahrain), although the energy-rich countries should learn from the recent Iranian subsidy reform experiment and start addressing the issue of domestic prices sooner rather than later.

Security And East-Med Gas

WALID KHADDURI considers hydrocarbon discoveries and security challenges in the Levant Basin

The US Geological Survey (USGS) estimates that the entire Leviathan Basin holds a mean approximation of 1.7 bn barrels of recoverable crude oil and a mean of 122 trillion cubic feet (tcf) of recoverable gas reserves. The Levant Basin includes mostly offshore territories of Palestine, Israel, Lebanon and Syria, as well as territory off Cyprus. Reservoirs within the basin mainly contain Mesozoic and Paleogene sandstones, near shore marine and submarine sandstones and Jurassic and Cretaceous shelf-margin carbonates.

This article will review briefly the offshore hydrocarbon discoveries in the Levant Basin, and dwell on security issues, including the Israeli objection to development of the gas discovery in Palestinian waters off the Gaza shore; the demarcation of the disputed Exclusive Economic Zone (EEZ) between Lebanon and Israel; and Turkey's intrusion in the region, on behalf of northern Cyprus which is occupied by the Turkish army and the Cypriot Turks under Turkey's occupation.

"Cyprus is envisaging the possibility of turning the island into a regional hub for exporting regional energy resources to Europe."

Egypt: The Initial Discoveries

The first gas discoveries in the region took place in the mid-1980s in Egypt's Mediterranean waters, north of Alexandria and Port Said, as a result of changes in Egyptian laws that equated the economic returns from gas discoveries with those from oil. This incentive encouraged the International Oil Companies (IOCs) to explore Egyptian territorial waters and increase the country's gas reserves from 36.4 tcf of gas in 1999/98 to around 77.2 tcf (with most of the incremental reserves in the Mediterranean waters). The offshore discoveries are located in the Eratosthenes Seamount and south of that in the Nile Cone. The US Geological Survey estimates the crude oil reserves within the Nile Cone as high as 4.266 bn barrels, and natural gas reserves as high as 425,935 tcf. Natural gas liquids (NGLs) are estimated as high as 11.464 bn barrels.

The discovery of huge volumes of natural gas prompted the government to expand its use domestically, accounting currently for approximately 55 percent of consumed domestic energy, and to undertake extensive export projects, both by pipeline and as liquefied natural gas (LNG) to Europe and regional countries – a policy that prompted much opposition in parliament and the media during the Mubarak regime. Hence, one of the first decisions by the new regime was to stop gas exports to Israel, and slow the flow of gas deliveries through the Arab Gas Pipeline (AGP) to Jordan, Syria and Lebanon. The opposition to these exports was due to the low price formulas as well as to the fact that the country should retain sufficient reserves for future use of natural gas domestically.

Palestine: Discovery but no Production

The Egyptian discoveries prompted IOCs to explore the eastern Mediterranean shore. The Palestinian Authority (PA) awarded in 1999 an exploration licence to British Gas (BG) covering the entire marine area offshore the Gaza Strip. BG drilled two successful wells in 2000 (Gaza Marine-1 and Gaza Marine-2) with reserves estimated at around 1 tcf of natural gas. BG was partnered by the Palestine Investment Fund and the Athens-based Consolidated Construction Company (CCC). In 2002 the PA approved the development plan of the field, as well as the construction of a sub-sea pipeline to an onshore processing terminal in Gaza, with production to start in 2006, and the gas to meet the energy needs of the Gaza Power Station, instead of importing the fuel from Israel – which permits and stops deliveries in accordance with its political priorities, causing rolling power shut downs. Meanwhile, Israel refused to allow the development of the field, demanding that supplies be transported first to Ashkelon so that it contributes to Israel's energy needs, as it was in the process of converting its power stations to the use of gas instead of coal. Israel also demanded that it be sold the gas at a discounted price. The BG-led consortium rejected these conditions. Accordingly, Israel has not allowed the development of the Gaza Marine Field, and the BG office in Tel Aviv closed subsequently.

Israel: Major Discoveries in Northern Waters

Petroleum exploration had very little success in Israel throughout the second-half of the twentieth century. The reasons are varied: drilling was mostly in onshore areas, and international oil companies and service firms were not ready to take the risk of working in Israel – fearing the boycott of the Arab countries. However, the situation changed after the signing of the 1979 Camp David accords and the Egyptian–Israeli peace accord, while the shift of focus was to exploration offshore with discoveries enhanced by the progress of advanced technology.

The initial discoveries were in southern Israeli waters close to Palestinian offshore territory. These initial discoveries were small in size and disappointing to the IOCs. BG discovered the Or field in November 1999 in the southern offshore waters, adjacent to Israel's first discovered commercial field, the Mary-B Field. Production of natural gas from the Mary-B Field started in 2004, averaging around 138 mn cubic feet daily (cf/d). The reserves are relatively small and expected to be depleted by 2013 – especially after the increased pumping from the field due to the stoppage of gas supplies from Egypt since the 2011 revolution. Palestinian officials have expressed their concern privately that the close proximity of the Mary-B field to their territory is siphoning gas from their own reserves.

A decade later, in 2009, a consortium led by Noble Energy with Israeli firms discovered in the Tamar gas field around 80 kms (50 miles) west of Haifa at a depth of approximately 16,000 ft. under the surface of the sea, with recoverable reserves estimated at 9 trillion cubic feet. The field is located in the Matan licence, consisting of three structures. The main one, situated around 35 km south of the Lebanese territorial waters, is being developed, with production scheduled in March/April 2013. There are also two small structures that straddle the Lebanese waters.

In December 2010, Noble Energy discovered the largest gas field so far in the Levant Basin, the Leviathan Natural Gas Field, situated approximately 130 km West of Haifa in the direction of Cypriot territorial waters and approximately 30 miles/55 km south of the Lebanese waters, covering about 83,000 sq. km of territory, with around 17 trillion cubic feet of gas reserves and 1.2 bn barrels of oil at a depth of around 20,000 feet. Production is scheduled for 2017.

The discovery of the Leviathan and Tamar fields in the northern waters has changed Israel's energy balance. Israeli officials are still studying what policy route to take, whether to go ahead with gas exports (either by pipeline to Europe or to convert it to LNG). The debate still underway in Israeli circles is to determine how much gas reserves they should retain for future domestic use, and whether the country should depend solely on gas fuel to generate electricity, as many are advocating now, with some worrying that the dependence on one energy source from one area could be an insecure source of supply.

Cyprus and Lebanon signed an agreement on 17 January 2007 on the 'Delimitation of the Economic Zone'. The Cypriot Parliament has ratified the agreement, while the Lebanese Parliament has not, for two reasons: the Parliament was closed for some two years, hence the Prime Minister could not send bills to Parliament for ratification; however, more important, is the objection of the Lebanese authorities to the extension of the demarcation line agreed to by the Cypriot authorities with Israel, asserting that the Cypriot–Israeli agreement, without Lebanese consent is contrary to Article 3 of the accord, which reads: 'If any of the two parties is engaged in negotiations aimed at the delimitation of its Exclusive Economic Zone with another State, this Party, before reaching a final agreement with the other State, shall notify and consult the other Party, if such delimitation is in connection with coordinates (1) or (6).' Much controversy surrounds the demarcation line. Cyprus states that Lebanon has not ratified the agreement hence Nicosia will not alter its accord with Israel. Lebanon asserts that the bilateral agreement between Cyprus and Israel is null and void in accordance with the Lebanon-Cyprus accord, and that it will not ratify the agreement until Cyprus annuls its accord with Israel.

Lebanon also asserts that the Cypriot–Israeli accord has detached 860 sq km of Lebanese offshore territory and proclaimed it as a disputed Economic Exclusive Zone (EEZ) between Israel and Lebanon. Diplomatic mediation by US ambassador Christopher Hoff to resolve the issue and return around 60 percent of the territory to Lebanon appears to have hit a roadblock. Lebanon is insisting that it retains all the disputed territory, since its claim over that territory is historical and Israel had not disputed that sovereignty. Moreover, Lebanon asserts that the area was only transformed into a disputed zone in accordance with the Cypriot–Israeli agreement. The net result of this dispute is that the Lebanese–Cypriot demarcation line will remain in limbo, and the Lebanese–Israeli EEZ will be an additional source of conflict between the two countries. The problem is that there are indications of hydrocarbon reserves in the disputed area, and the possibility of fields extending from the territory of one country to the disputed territory will make it difficult to ignore. Furthermore, both Israeli officials and Lebanese Hizbollah leaders are already threatening each other over trespassing into the rights and interests of the other. Israel has not included any part of the EEZ in its concession areas. Lebanon has not published a concession map yet. It is doubtful that an international firm will risk exploring in this disputed and volatile area until the issue is resolved. However, it is possible for either country to explore in other parts of its territorial waters and not revert to this disputed zone until the issue is resolved.

Cyprus: A Regional Gas Hub

Cyprus is envisaging the possibility of turning the island into a regional hub for exporting regional energy resources to Europe. Noble Energy announced in December 2011 the discovery of the Aphrodite gas field in Block 12 in Cypriot waters, adjacent to its discoveries of the Leviathan and Tamar fields in Israeli waters. Estimated reserves are around 7 tcf, which is more than meets Cypriot's energy needs. Meanwhile, the Cypriot authorities are now evaluating the bids of the Second Bid Round, which has proven to be much more successful than the first one.

The discovery of hydrocarbons in Cypriot waters has revived once more the conflict of the Republic of Cyprus (recognised internationally and a member state of the European Union) with Turkey, which occupies the northern part of the island (recognised only by Turkey). Turkey has put forward claims over the Cypriot waters, asserting that it is defending the interests of the occupied northern part and the Turkish Cypriots. It has even threatened drilling by IOCs in Cypriot waters, as well as threatening IOCs applying to the Cypriot Second Bid Round that they would not be allowed to operate in Turkey. There are several reasons behind Ankara's policies: to forge an agreement to unify the island; declare the East Mediterranean as a semi-closed sea, hence asserting the right to intervene in the drawing of demarcation lines – as it has done while drawing the Cypriot–Syrian line and the demarcation of the Cypriot–Lebanese line, and opposing the rise of the Israeli-Cypriot-Greek energy/political alliance.

The tripartite energy alliance is one of the most important geopolitical developments emerging from the gas discoveries in the East-Med. Cyprus has had very friendly relations with neighbouring Arab states (Egypt, Syria, Lebanon and the Palestine Authority). However, the discovery of gas, and the intransigent role of Turkey have given rise to a different geopolitical perspective: how to protect the Republic's natural resources and defend its interest from Turkish threats. An alliance is gradually evolving with neighbouring Israel, which has already discovered much gas reserves – enough to export, although no formal decision has been taken yet on the subject – and with the Republic's traditional ally, Greece, to join hands together. There are many proposals, but no final decision yet as to what route of cooperation this new alliance would take. What is clear is that it would entail the export of a new energy source to Europe. There have been several business proposals on the table: the export of electricity by Israel and Cyprus through Greece to Europe; export by pipeline the gas from Israel and Cyprus through Greece to Europe; finally, the construction of an LNG plant in Cyprus that would liquefy Israeli and Cypriot gas for export to Europe.

Conclusion

There are already three security challenges confronting East-Med gas, even before production has started in earnest (Gaza, the Lebanese–Israeli EEZ and Turkey–Cyprus). Each one of these disputes is volatile and could expand into a regional conflict. With the volatility of the region, and the lack of demarcated borders, it cannot be dismissed that other conflicts would be ignited.

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