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Africa has for a long time assumed the role of the world's most neglected energy province. In large, this has been due to the region's comparably small reserve base for oil and natural gas – despite notable exceptions as in the cases of OPEC members Nigeria, Angola, Algeria and Libya. The significance of the African reserves for international energy markets is nevertheless large, for as one of our authors outlines, African oil and gas production is primarily exported in the face of until now marginal domestic energy consumption. New discoveries, particularly in Africa's formerly hydrocarbon-poor east, have sparked a new wave of developments that are likely to change the face of Africa as an energy producer. Enough reason for this special Oxford Energy Forum to focus on Africa's energy outlook.

Ivan Sandrea starts off, exploring the upstream successes in Africa's oil and gas industry. He confirms the view that as a result of the new discoveries in the last decade, in particular in Central and East Africa, Africa's upstream industry and energy outlook has changed dramatically; in particular its upstream future may look now to be more gas rich than previously thought. The continent's main challenge, he believes, remains the commercialisation of its newly found resources in view of the lack of sectoral experience of new producers, and Africa's long history of unsatisfying commercial outcomes in existing producers.

Monica Enfield looks at Africa's shifting risk structure for upstream projects from the investor's point of view. Above-ground risks in her view will undoubtedly constitute some of the key risks encountered by future E&P partners, including lacking government services in areas of company operations, monetisation risk or expensive infrastructure needs to commercialise resources, and political risk and associated risks resulting from local levels of corruption. Foreign investors' 'social license' to operate, Enfield argues, in the future will more often depend on companies' ability to manage these risks while providing host governments with high value-added.

Elias Pungong further discusses the impact of East African natural gas on the subregion's economic development. Success in his view requires a delicate balance between local and investors' interests to secure long-term attractive deals for both sides, possibly under a region-wide gas development master plan. *Chekib Khelil* adds to this view by pointing out some of the key challenges faced by Africa's energy infrastructure in the area of accessing finance. Khelil advises that successful future cooperation deals between host governments and energy companies require a transparent and reliable set of legislation and regulation, enforced by politically stable host countries, and with the right balance of risk between the contracting partners.

Alex Vines reflects on East Africa's impact

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on Africa's wider energy market development. Drawing lessons from previous experience, Vines proposes that African governments need to act swiftly in order to let their economies benefit from the newly found resources, including the need to 'strengthen independent institutions and oversight; publish all the taxes and royalties from oil; do not rush into prestige projects and extravagant consumption and don't neglect creating meaningful employment.'

Several of our authors look at specific country cases. The views are generally encouraging on Africa's new hydrocarbon province East Africa. *Anne Frühauf* discusses the case of Mozambique and assesses the country's current investment framework in view of its plans to start production from its offshore fields as early as 2018. Frühauf argues that the country has all the basic political and regulatory fundamentals in place to start production on time, but cautions about Mozambique's ability to cope with unexpected political and institutional pressures that may yet be associated with the coming years' resource boom.

Oswald Clint and *Rob West's* view on Angola's pre-salt developments is more cautious; albeit viewing Angola's reservoirs as promising, they question whether the country's reservoirs in the South of the Kwanza basin will be as prolific as those found for instance in Brazil. *Eduardo Pereira* and *Elison Karuhanga* in the following article explore the effect of government regulation on Uganda's and Brazil's upstream prospects, arguing that both countries are losing valuable time as a result of political interference in the sector which sparks legal uncertainty for needed foreign investors.

Our authors' most pessimistic outlooks deal with Africa's traditional oil producers. *Amrita Sen's* account of Nigeria's production prospects is more than bleak. Despite being Africa's largest oil producer, the country has suffered from political turmoil for more than two decades in a row. The implications of lacking political stability for the oil sector have been vast: Nigeria' s oil sector today is characterised by what Sen calls 'wastage, corruption, low productivity and unchecked dominance of foreign multinationals'. The world's capital of fuel smuggling, Nigeria loses up to $40 million per day in illegal bunkering. Obsolete legislation and lacking funding for the sector suggest in Sen's view a continuingly poor performance of Nigeria's upstream sector.

Adeola Adenikinju discusses Nigeria's 2011 fuel subsidy reform and its impact on Nigeria's domestic market. In Adenikinju's view, the reform failed to achieve any of its objectives after the government revoked initial fuel price increases owing to rising popular pressure. The implications for Nigeria in his view are largely negative: continued fuel subsidies waste Nigeria's natural resources and encourage the country's legacy of fuel smuggling and illegal bunkering.

In his piece on the two Sudans' struggle for stability, *Bill Farren-Price* discusses prospects for a resumption of Sudanese oil exports in the coming year. In his view, South Sudan should be able 'to restart some oil production relatively swiftly once technical problems are overcome' following September's peace agreement between Sudan and South Sudan. However, he believes that Sudan's export pipelines are vulnerable to disruption, especially if fighting in the border zones continues. Progress beyond the September agreement in securing border provinces will also be critical to help South Sudan achieve pre-crisis production levels of 450,000 b/d, a shared target driven 'by the economic imperative of restarting oil exports, on which both are so reliant for state revenue.'

Finally, in a response to our previous issue No.89 on natural gas demand and supply, *Axel Wietfeld* draws attention to a theme he felt was left out of the discussion: European underground gas storage and its importance for European gas supplies.

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The Building Rocks of Africa's New O&G Industry

IVAN SANDREA explores key themes for Africa's energy outlook over the coming decade

During the last decade, new ideas, rising prices, political risk bets, technological developments, and rising capital expenditure supported a significant expansion of global exploration efforts and of the resource base. In the period 2000 to 2012 year to date, over 800 billion (bn) boe of new resources (conventional and unconventional), have been discovered globally. Of this, conventional resources account for approximately 380 bn boe (2P) while the rest is attributable to unconventional resources, both of which are just starting to change the long-term outlook of the global O&G industry.

The most important conventional resource exploration themes of the last few years include new discoveries in the FSU (Caspian), China onshore, Australian offshore, Brazil pre-salt, US GoM deepwater, Kurdistan, and notably Africa with discoveries in both petroleum rich countries as well as in half a dozen new countries.

Africa has without doubt been a major beneficiary of global exploration success efforts. Cumulative discoveries totalled 60–70 bn boe (2P) or 20 percent of the total global additions during the period 2000 to 2012 year to date. And more than half of this was added since 2007 and with a large part of it being gas. Discoveries have been made in all settings – onshore, below a lake, shallow water, deepwater, in new countries and/or basins with little or no exploration history. No unconventional reserves have been added (yet) to the inventory despite the fact that the continent has substantial heavy oil/bitumen and potentially shale gas.

Importantly, the big four heavyweights taken together – Algeria, Egypt, Nigeria, and Libya, which have traditionally accounted for the bulk of the region's production and reserves additions – for the first time in history added fewer new reserves than the other African countries combined. In other words, the club of the big four ceased to be an exclusive club. From the perspective of exploration results, the new clubs are:

- Emerging West Africa – Angola deepwater (new pre-salt province), Ghana deepwater (new province), Mauritania deepwater (new province), Ivory Coast deepwater (new province), Gabon deepwater (pre-salt)
- East Africa – Mozambique deepwater (new province), Tanzania deepwater (new province), Kenya onshore and deepwater (new provinces)
- Onshore Central Africa – Uganda (new province), Niger (new province), Sudan, South Sudan, Chad

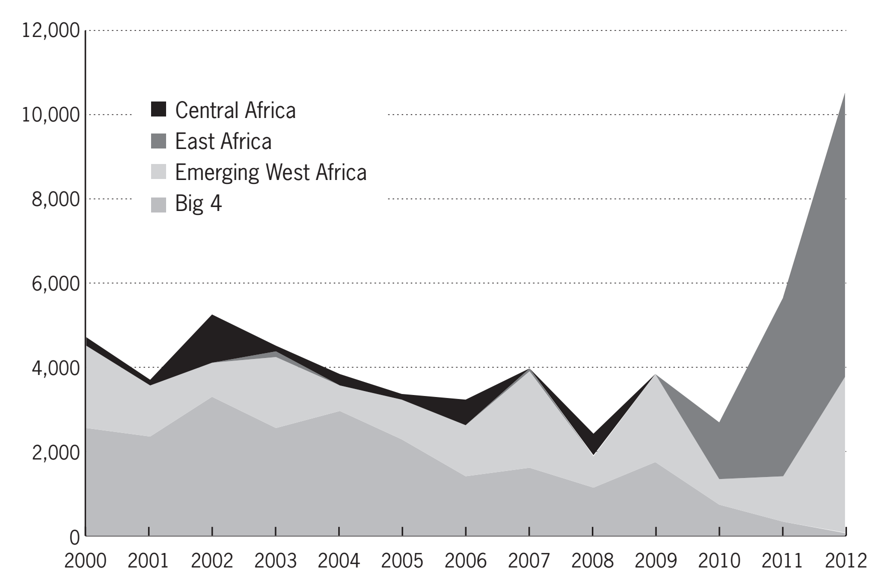
Since 2000 to 2012 year to date cumulative new discoveries in Emerging West Africa are estimated at 19.2–22 bn boe, in East Africa 12.5–20 bn boe, totalling 35–46 bn boe, and in Onshore Central Africa 3.2–4 bn boe. In the big four, a total of 23 bn boe has been discovered but it is worth noting that annual discoveries in the big four peaked in 2002 and since 2009 the annual discovery trend has been on a rapid decline. It appears that there are both below and above ground reasons for this deterioration. (Figure 1)

There are many other countries in Africa that are not part of any club (yet) such as Liberia, Sierra Leone, Somalia, South Africa, and Morocco. These have seen new basin tests and/or discoveries, but all have been of insufficient scale and geologically insignificanct. Cumulative discoveries in the rest of Africa totalled 600 mboe or just 1 percent of the total Africa.

Africa stands out as one of the most active continents when it comes to licensing activity, exploratory activity, new discoveries, and new development projects. In terms of E&P M&A, the continent accounted for just 6 percent or approximately $8 bn of the annual value of global deals in the last few years. Having said this, the competitive landscape in Africa has become crowded with players ranging from domestic NOCs, Asian NOCs, international majors, international independents, regional and local players, to name a few. However, it is interesting to note that the Chinese NOCs, despite their decade long presence and success relative to other Asian NOCs, have been absent in new E&P games such as Angola's pre-salt licensing round and gas discoveries in East Africa.

Given the recent successes and in particular the type of new reserves, likely development needs (i.e. long distance pipelines, gas, LNG, FLNG), and type of

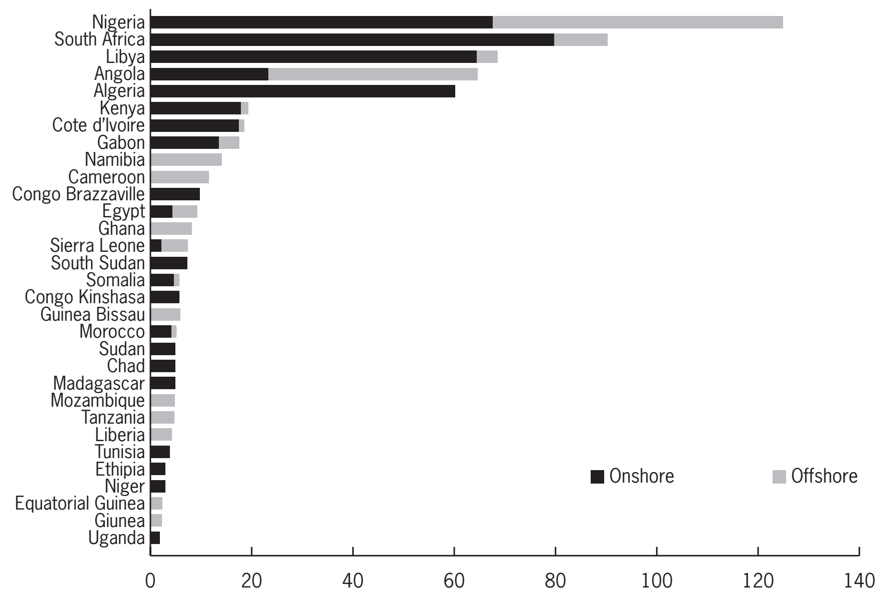
Figure 1: Chart of New Discoveries, Africa (bn boe)



Source: Sandrea & Enfield (2012), Company announcements, Bernstein players, competition in exploration and in M&A will continue to increase as the regionally successful companies such as Tullow and smaller look to cash out, seek capital to develop the resources or simply become targets of bigger players.

Looking to the future, global Yet to Find (YTF) stands today at close to 4 Tn boe. Of this, the African continent accounts for 1 Tn boe or 25 percent of the total. In Africa, the majority of the YTF is expected to be found in conventional reservoirs. New discoveries will take place in deepwater pre-salt reservoirs (i.e. significant presence in Angola and Gabon), traditional deepwater turbidites and new cretaceous plays, rifts basins (central Africa), in old intra cratonic sedimentary basins (i.e. Chad, Sudan), to name a few. It is possible that we will see more gas than oil, but oil still dominates. (Figure 2)

Figure 2: Africa Yet To Find (bn boe)



Source: EIG, modified by author

Longer-term efforts are also being made to understand unconventional resources, which if proven commercially will be added to the inventory. Large quantities of heavy oil/bitumen are known in several countries but particularly in Congo (Brazzaville), Nigeria, and Madagascar whilst shale gas deposits are thought to exist in South Africa, Algeria, Libya, and Tunisia.

Beyond the big four, the new clubs of countries underpinned by new discoveries in the last decade, another half dozen countries are seeing rising exploration efforts such as Malawi, Zambia, Ethiopia, Burundi, Zimbawe, South Africa, and Namibia for which we have little or no data. And whilst conventional wisdom and present day geological understanding tell us that there are unlikely to be large-scale petroleum basins in most of these countries, as we have seen, new finds such as those in Kenya and Uganda are sufficient to change a company, a country and in aggregate, a continent.

From a resource perspective, Africa's O&G industry has undoubtedly changed and will continue to change, particularly as new discoveries are brought on stream and exploration efforts diversify. Now as someone once said to me 'since the easy part of discovering the hydrocarbons has been done, the resources must now be commercialised' and that is Africa's next challenge.

Africa's Risk Outlook

MONICA ENFIELD argues that above-ground risks are likely to impact Africa's future energy outlook

Africa is a strategic component of the global energy system, but a number of above-ground risks are likely to impact the region's future outlook. Other authors in this issue have outlined in detail the geological potential and exploration context for African hydrocarbon resources, and the region is set to receive billions of dollars in investment in the coming years. However, for many of these African reserves to be monetised, operators will need to manage new above-ground challenges. Whereas just a decade ago, 'risk' mainly centred on political stability and economic uncertainty, companies now face surface and regulatory risk issues that are necessary to secure a 'social licence' to operate. Operators' ability to manage these largely non-technical, socioeconomic risks will be critical to the pace of resource development in Africa. This article looks at the varying and evolving risk landscape in Africa.

Although it is smaller than other regions with regard to proven oil and natural reserves and production, Africa remains strategic to global energy markets because of low domestic resource requirements allowing for export to global markets, the relatively high quality of its resources, and because it remains open to foreign investment. Africa exports almost all of its hydrocarbon and natural gas production, rather than consuming it domestically, primarily serving North American, European and Asian demand centres. This was especially important when Chinese demand for crude and refined products began to increase rapidly as African production growth helped offset declines in the North Sea and other light sweet crude producers. West African crude in particular contains sizeable amounts of gasoil, which can be refined into higher value distillates (diesel, kerosene, heating oil). Although the refining slate in both the United States and China is shifting toward a heavier and more sour crude slate, the light sweet West African barrels remain an important swing crude in global trading.

But more than simply the quality of the crude, the African region remains strategic because it is largely open to foreign investment. A number of host governments allow energy companies to 'book' assets for reserve replacement and equity production as part of their overall company value. And even in the African OPEC countries (Nigeria, Angola, Algeria and Libya), the risk of production cuts to align with market management strategies has not significantly deterred investors.

Indeed, almost every country in Africa is receptive to hydrocarbon licensing and investment. For the purposes of this article, there are five key exploration and production (E&P) regions in Africa, each with differing resource development outlooks. North Africa is primarily an onshore conventional play, with a decades-long history of E&P activity from both foreign investors and the host national oil companies. At present, activity is hampered by the current political unrest across the broader Arab world and relatively restrictive fiscal terms, such as in Algeria and Libya. The Gulf of Guinea – encompassing a region that extends from Nigeria to northern Angola – is the key production centre in Africa over the last several years. E&P activity in the Gulf of Guinea includes conventional onshore/shallow water, as well as deepwater and more recently, even pre-salt plays. Nigeria and Angola are the leading resource holders and producers in this sub-region, and deepwater projects throughout the Gulf of Guinea drive substantive production growth in the future. The region has attracted all type of investors in the past two decades, with capital and technology-rich Supermajors dominating the deepwater space while local, regional and independent E&P firms are active in mature and conventional plays. An emerging frontier region, the Equatorial Margin is mainly a deepwater play with associated natural gas volumes. With a geological analogue across the Atlantic Ocean in Latin America, the African Equatorial Margin (also called the Transform Margin) extends from Ghana to Guinea Bissau. There is a range of political stability and risks issues across the region that is likely to stall potential resource development, especially in near-failed states Guinea and Guinea Bissau. The East Africa Rift Basin is a conventional onshore play, and infrastructure needs will be a primary commercialisation obstacle. The Mozambique Channel is a deepwater natural gas play, and is likely to be commercialised via LNG. Offshore security concerns (in the context of piracy threats) and emerging natural gas policy frameworks are likely to be key challenges for investors.

In terms of the competitive landscape in Africa, for decades the Supermajors explored onshore acreage across the continent, taking advantage of tax and royalty concessions. In the 1990s the Supermajors pushed the region's hydrocarbon potential even further by investing in the deepwater region, which at the time was considered anything deeper than 1000 feet. This new frontier required extensive capital and technology, and production sharing agreements were implemented that allowed more upside potential to operators concerned about recouping large upfront expenditures in risky conditions. However, Supermajors are not the only actors in Africa. Smaller independent E&P companies are very active in the region, particularly in so-called 'frontier' countries, where there has been very little past exploration activity. These smaller players are important because they have a narrowly-focused exploration-led business model (in contrast to Supermajors which manage large complex portfolios across the value chain), usually have much higher corporate risk tolerance than Supermajors, and are willing to develop smaller hydrocarbon deposits that may be uneconomic to bigger companies.

This varied mix of operators will mean different corporate drivers and abilities to manage above-ground risks. In general, Africa has a common set of challenges for investors: political instability (internal unrest or spillover impact from regional conflicts); high levels of corruption; low levels of social development and lack of government services in areas of company operations; high levels of monetisation risk or expensive infrastructure needs to commercialise resources; and weak sectoral capacity with limited institutions to manage the hydrocarbon sector. These risks tend to evolve as the resource base moves from a frontier exploration phase, to production ramp-up, to production plateau, and then to a mature production stage (Table 1).

In the frontier exploration phase, the primary driver is for operators to 'de-risk' the play from a geological perspective, and includes industry activities such as licensing, seismic acquisition and exploration and appraisal (E&A) drilling. For the government, the primary driver is to secure investment with attractive fiscal terms, quick approvals and low levels of regulatory burden and oversight. This is to encourage rapid exploration commitments by license holders, and is generally characterised by lower levels of entry and operating risks. Guinea in the Equatorial Margin and Ethiopia in the Rift Valley play typify this stage of development.

However, once resources are proved up in the country, above-ground risk tends to rise, especially in the production ramp-up phase. This period is when operators undergo project conceptualisation and make infrastructure investments and seek project approvals and environment permitting from the relevant authorities. At the same time, the prospect of new resources can change the government's needs and expectations from the sector. The state often begins to build capacity to manage state resources, including creating new institutions and national oil companies, as can be seen in Ghana, Tanzania, Mozambique and others. Although keen to begin receiving project revenues, the state may also seek to change contract terms in order to secure higher government take, and may insert the new national company as an equity partner in the project, or even stipulate new requirements on monetisation of resources. Uganda's requirement that crude oil be refined domestically rather than be allowed for export illustrates a key risk in the land-locked Rift Valley basin countries.

In many frontier African plays, where oil or gas resources have even yet to be declared commercial, governments are soliciting the advice of the World Bank, international transparency organisations and other national oil companies to provide best practices, capacity development funding and training. A primary driver for the pre-emptive regulatory frameworks and more stringent fiscal terms is for host governments to avoid the 'resource curse'. Numerous studies have demonstrated that countries with abundant natural resources have slower economic growth than countries without natural resources. 'Resource

Table 1: Above-ground Risk and Investor Impact

Resource Development Stage	Frontier Exploration	Production Ramp-up	Production Plateau	Mature Production
Industry Activities	Licensing Seismic acquisition E&A drilling	Project conceptualisation and infrastructure investment Project approvals Environmental permitting Production management	Production management Additional E&A drilling	EOR applications
Government Objectives	Secure investors with attractive fiscal terms, quick approvals and low regulatory burden Encourage rapid exploration commitments by licence holders	Build capacity to manage state resources Includes new institutions and NOC Revenue generation	Revenue generation Value-added investment linkages NOC and local sector development	Retain and attract investors Revenue generation from sector and value-added investments Opportunities for NOC and local sector
Above-Ground Risks	Low entry risks Low operating risks	Higher government take Contract sanctity Rising NOC mandate and influence Export restrictions	Pressure to invest in 'value-added' sectors (downstream, power, petchem) Rising local content Nationalisation	Decreasing entry risks, but strong NOC presence
Country Example	Guinea Kenya	Ghana Mozambique/Tanzania	Nigeria Angola	Sudan Gabon

curse' countries also suffer from lower levels of democracy, weak institutional capacity, poor human resource development, higher levels of conflict, revenue volatility, excessive borrowing during economic crises, and rampant corruption. All such characteristics can be found in many existing Gulf of Guinea producers, and the new African frontier countries are keen to avoid this fate.

For the East African gas countries, the number of recent discoveries has prompted a paradigm shift in the way natural gas is viewed in the region. Previously, natural gas was seen as a liability when accompanied with crude oil exploration efforts, with no perceived market for consumption or other cost-conscious commercialisation options. Gas resources were often flared, stranded or in the case of Nigeria, put towards LNG projects that provided further revenue flows to the government. The new gas paradigm is one in which African governments place natural gas at the centre of its economic development strategy. Tanzania and Mozambique in particular view their deepwater natural gas resources as a 'development fuel' that will build up the domestic economy and provide linkages to other value-added investments. While the scale of the recent discoveries will support an LNG commercialisation strategy (indeed several trains are under consideration by operators), the governments envision utilising a portion of the resources at home and expect foreign investors to be their partners in development.

In the case of Tanzania, the state is reviving its development plans, as illustrated by changes in natural gas legislation. Five key legislative components are being drafted, and are expected to be completed by 2013. Anticipated changes in investment terms include increasing royalty rates, the introduction of a signature bonus or signing fee, and the implementation of international industry standards, including new sector-specific regulations and requirements, especially around HSE requirements. Tanzania is also considering the creation of a sovereign wealth fund to help channel hydrocarbon revenues into development and savings for future generations. Similar efforts are taking place in Mozambique and Kenya.

The bulk of the Gulf of Guinea and North African countries are in the production plateau phase, in which the industry is engaged in production management and additional exploration and appraisal activities. Revenue generation from exports and taxation is a key government driver, but the state is also concerned with value-added investments and development of the local sector. There is increased pressure on foreign companies throughout these two regions to invest in sectors beyond just upstream such as the refining, petrochemical and power industry, as well as increased local content demands and creating opportunities for local operating companies to acquire assets and acreage. The current Petroleum Industry Bill (PIB) in Nigeria is demonstrative of the types of risks seen in this phase of development, and once implemented will make a number of regulatory, operational and fiscal changes to Nigeria's upstream and downstream sector. Industry actors have criticised the worsening fiscal terms, however the net effect of the PIB is likely to result in an overall positive impact on the investment climate. By raising Nigeria's institutional capacity, the PIB will enhance the investment climate stability and predictability of future changes to contract terms, as well as opening the way for new licensing rounds, contract renewals and investments in Sub-Saharan Africa's largest hydrocarbon resource-holding state.

At the tail end of the production phase, the risk profile tends to improve as mature resources are managed. The government is primarily concerned with retaining investors or attracting new players that specialise in enhanced oil recovery applications to maximise resource exploitation. Entry and operations risks are usually lower in this phase, but the national oil company and local firms boosted by previous government policy remain relevant and influential players. Gabon and Sudan typify this stage of risk evolution.

Throughout all these risk phases in Africa, surface-level risk issues feature prominently. Certainly in the context of the US Gulf of Mexico Macondo spill, there is greater host government focus on environmental and safety procedures, with varying levels of capacity to develop and enforce regulations in Africa. Even though higher regulations in some states may add to project costs and compliance delays, an absence of regulations in other countries will still represent a liability to operators in the event of accidents or environmental disasters. In order to obtain a 'social licence' to operate, companies will need to manage risks associated with evolving energy policies and fiscal frameworks, social development issues, varying levels of state regulatory capacity, increasing environmental liabilities, as well as an array of risks that impact operating conditions, such as operator safety, corporate reputation and local community relations. ■

Africa's Gas (R)evolution

ELIAS PUNGONG argues the case for a meaningful, practical African master gas development plan

Economic growth has typically been driven by the development of natural resources, including oil and natural gas, as 'foundational' elements. In developing countries, natural resources development typically accounts for a significant part of the state revenues and more importantly, it represents a 'prime mover' for employment, infrastructure development and the improvement of the broader social wellbeing. This is not different in Africa where gas development is set to drive economic growth on the continent for decades to come.

With the need for countries to find alternative and sustainable energy sources, many are looking at the development of natural gas as that alternative, for it is the only fossil fuel whose share of the global energy mix is expected to grow. That expected growth is to be driven by developments on both the demand and supply side. This applies also to the African gas development story. As of 1 January 2012, proven reserves of natural gas in Africa are estimated at around 14 tcm. African gas reserves are about 7.5 percent of the world's total. Technically-recoverable reserves of natural gas in Africa are substantially higher, estimated to be about 74 tcm, almost 10 percent of the world's total. This figure is set to increase, forecasting that African natural gas production will grow at an average rate of about 2.7 percent per year, expanding to almost 400 bcm by 2035 while consumption is expected to more than double, reaching over 230 bcm by 2035.

Currently in Africa, 92 percent of the continent's total proved gas reserves are highly concentrated in Nigeria, Algeria, Egypt, and Libya with North Africa representing the 'Old Guard'.

Algeria has long been a major player in global gas markets, and it has historically been the second-largest gas supplier to Europe. It is seen as a reasonably open and mature market for oil and gas exploration and production. Libya's natural gas is still secondary to oil in the country and is relatively underdeveloped. As a result of the US sanctions over recent decades, foreign participation had been dominated by the European majors.

In recent years however, the rest of Africa has been making strides in the production of gas. This has largely been driven by Nigeria and Angola. West Africa has predominantly been an oil story but over the last decade or so the sub-region has increased its natural gas. Much, if not most, of the gas output has been flared; only relatively recently has there been a dedicated focus on capturing the gas for export as liquefied natural gas (LNG). Importantly, the World Bank's Flaring Reduction initiative has had a major focus on the sub-region, with those efforts tied in with the export projects and with the development of the local infrastructure to support domestic gas use.

East Africa, which ten years ago was a 'non-story' as far as oil and gas is concerned, is now seen as the 'next epicentre' for global gas. The region is enjoying the most dynamic developments in the African natural gas story. This has catapulted interest in neighbouring offshore Kenya and Madagascar in the belief that similar geological compositions will be found. More recently, drilling activity has been picking up elsewhere on the continent, notably in offshore East Africa in Mozambique, Tanzania and in South Africa, where the Government recently lifted the moratorium on the controversial exploration and extraction of shale gas identified in three formations in the Karoo Basin.

In its quest to drive the continent's growth, the gas development story carries both challenges and opportunities for governments, investors and the broader society. Even though the challenges are great, the opportunities far outweigh them and with production reaching around 203 bcm in 2011, 4 percent annually, they will soon surpass the risks involved. Some of the identified challenges are:

- A possible continued global economic recession, with resulting restrained energy demand growth and reduced energy investment; in particular, a significant slowdown in China, a crucial economic partner in much of Africa, could adversely impact trade flows, aid, and investment flows.
- Societal acceptance of unconventional gas development, particularly as related to hydraulic fracturing and

the potential environmental impacts on water (i.e. water supply, potential ground-water contamination, and waste-water disposal) and/or the possible causal relationship to seismic activity (i.e. earthquakes).

- Domestic gas demand growth, building local/regional gas distribution infrastructure, integrated local/regional economic and industrial development must be thoughtfully planned and coordinated, and
- Political instability, failure to develop stable, fair fiscal/legal regimes and systems, corruption perceptions/business culture/ease of doing business and lack of existing gas production/supply infrastructure in some frontier regions – increased investment requirements.

If there is a concerted effort by all involved, these challenges will not be insurmountable. This focus is paramount especially since Africa is currently enjoying an unprecedented period of sustained economic growth. According to the 2012 Ernst & Young Africa Attractiveness survey, over the past decade, African economic output has more than tripled. This has brought on investment and infrastructural development opportunities that will surpass the challenges and risks in the future. For example, the construction of Africa's first regional gas transmission system, the West African Gas Pipeline (WAGP), commenced operations in 2011, runs from Nigeria through Benin and Togo, and feeds into two power stations in Ghana. On 1 July 2012 interested shippers became eligible to sell their natural gas via the WAGP system.

The opportunities are immense for investors. By and large, with relatively open access and generally attractive leasing terms, the international majors, particularly the European-based ones, have done well in Africa. As elsewhere, their financial might and their deep technical capabilities and operational experience have provided them with a competitive advantage. But the region has also long attracted the large international E&P companies, who brought extensive technical capabilities and experience, plus a typically sharper strategic focus and usually a sharper appetite for risk. The larger independents have also been joined by a growing group of smaller, more-nimble independents and regional 'specialists'.

The private sector companies have been joined by a host of indigenous national oil companies (NOCs), some of which are very technically competent in their own right, others less so and often bogged down in bureaucratic inefficiencies and overwhelmed by the challenges of developing local technical, commercial, and managerial capabilities. NOCs from outside Africa have also played an increasing larger role in the oil and gas sector in Africa. In particular, NOCs from emerging markets have been actively investing in African assets, infrastructure and smaller private companies.

Africa's gas development story will be more than just headline opportunities for the NOCs, the deep-pocketed oil and gas majors, their big international E&P counterparts, and the well-known African oil and gas specialists. Opportunities will extend in most areas to the smaller, local E&P players as well, usually in partnerships with the larger, more experienced players.

The ramp-up in E&P activity of course brings opportunity for the Oilfield Services (OFS) segment, but again, not necessarily just for the big international OFS players, but also for local and regional companies that can contribute to the supply chains and to the associated upstream support infrastructure build-out. The broader infrastructure build-out may also include massive export facilities, as in the case of LNG, as well as smaller projects such as pipelines and gas distribution networks to support local/regional domestic gas demand. All of this build-out can bring substantial local/regional opportunities. And certainly the associated development or expansion of a domestic gas demand sector could bring substantial commercial opportunities in the power generation, industrial and even transportation sectors.

African governments and local/regional NGOs will of course have critical roles to play – first and foremost, developing a meaningful and practical master gas development plan, one that addresses the upstream tax and licensing models, as well as the necessary infrastructure issues and investments, and local training and job creation issues. Collaboration and partnerships with the IOCs, both big and small, will likewise be critical. While short-term risks from the global economy are still quite high, longer-term economic prospects for Africa are seen as very bright. It is envisaged that with this steady growth a young, growing and urbanising population should enjoy a 'demographic dividend' and support an emerging, consuming middle class. ■

A Framework for Investment in Africa's Energy Infrastructure

CHAKIB KHELIL draws lessons for successful future investment in Africa's E&P infrastructure

Eighty percent of world energy demand by 2035 is expected to be met by oil, natural gas and coal, with 90 percent of the demand increase expected to come from non-OECD economies, and China accounting for 23 percent. According to the IEA, US$ 38 trillion are needed to meet projected demand through 2035. Combined with supply rigidities and the need to develop increasingly expensive sources of oil and natural gas, prices are expected to remain strong in the long term. With exports of 570 million tons of oil equivalent, Africa overall is today an energy exporter accounting for 43 percent of total African exports. The USA and China respectively cover today 22 percent and 30 percent of their oil imports from Africa.

However, while Africa today holds 10 and 8 percent of global proven oil and gas reserves, it remains underexplored with only 1000 wells drilled offshore and onshore compared with 18,500 drilled in Alberta alone in 2005. The last few years have seen the discovery of major oil and gas reserves in new exploration basins in

Ghana, Uganda, Kenya, Tanzania and Mozambique outside the more traditional oil and gas areas and countries. These new discoveries prove that several of Africa's remaining unexplored sedimentary basins promise to contribute an even larger share to the world energy needs in the future.

In addition, Africa is strategically located with respect to major energy-importing regions of Asia, America and Europe. Finally, Africa is attracting lots of interest from emerging economies. In 2010, total foreign direct investment was only about $55 billion but remarkably more than five times what it was a decade earlier. While a generation ago Brazil, Russia, India and China accounted for just 1 percent of African trade, today they make up 20 percent and by 2030 the rate is expected to be 50 percent. Taking additional factors into account, the World Bank considers that 'Africa could be on the brink of an economic take-off much like China was 30 years ago and India 20 years ago'.

Tackling Challenges in Africa's Energy Sectors

Considering world energy needs and the clear energy export potential of Africa, one of the key challenges, but also the key opportunity for Africa, is raising capital and closing the financing for future major energy export projects. These are typically very long-term projects. To be successful according to lessons learned from major international and African export projects, they require substantial alignment of long- term interests of cooperating countries and companies and they need to achieve a positive economic and political impact on the exporting and importing regions. Raising capital for a major energy export project can only be successfully achieved if the following underlying issues have already been satisfied:

- a guarantee of dedicated reserves over the life of the export project;
- assessment of its environmental and social impact and its mitigation;
- the impact of the local demand as it might affect the long-term sustainability of the project;
- the separate strategies of the companies partnering in the project and their individual financial and operational capabilities;
- the project's economic robustness taking into account cost assessments and potential cost overruns and the market characteristics;
- the capability of the executing body to carry out the project depending on its experience with similar projects and environment both upstream and downstream;
- and, the market risks in both its local and international component balance with assurances that progress has been made in marketing output to committed credible buyers and the attractiveness of these deals.

When satisfying each of the above issues, associated risks should be recognised and covered by the body better placed to address the corresponding risk. It is clear that the host country should cover the following risks: political, environmental liabilities, local hydrocarbon demand and pricing, local service industries capacity, local infrastructure existence or requirements (water, electricity). The partnering companies in the project should cover the following risks: below-ground technical and geological risk, and above-ground technical, engineering, financial and market risk. While each party is well placed to cover certain risks, each is well advised to consult and cooperate with the other.

Specifically, political risk is best covered by the host government by issuing the appropriate legislation and regulations and putting in place the corresponding regulatory institutions staffed with competent personnel. Legislation and regulations should be transparent, attractive and competitive and facilitate investments. Legislation should also be transparent in its application and should provide a stable and predictable framework in the long term. In particular it should provide a competitive and stable fiscal framework for both upstream and downstream investments that achieves a balance between the economic interests of the different parties (government, companies) and provides a fair return for the various risks taken by the partnering companies.

The Role of Legislation

Government institutions should be established with trained professionals to facilitate dealing with any investors' concerns, with easy access for arbitrating issues and if required recourse of the parties to an independent judiciary. Legislation should also clarify issues on taxation, foreign exchange, and regulatory hurdles for upstream and downstream investments as well as environmental and social liabilities. Changes in legislation should be minimised in order to avoid the negative perception of an unstable legislation that discourages long-term investments.

Legislation should also deal with local demand for hydrocarbons in terms of volume requirements and pricing as well as other requirements dealing with local service industries, local infrastructure needs and the training of local employees of foreign firms.

Local demand requirements in relation to major energy export projects have been addressed differently by, for example, Nigeria, Egypt, Indonesia, China, Malaysia, Australia, and Algeria. The main lesson to be learned from these countries is the need to put in place measures to satisfy local demand without putting at risk the continued encouragement of upstream supply in the long term.

Well designed legislation and regulations, and efficient government institutions are key to providing project sponsors and financing institutions with the means to facilitate the smooth implementation, financing and operation of a long-term major energy export. Project financing with no recourse to corporate debt of the project sponsors would also be facilitated by the appropriate legislation and guarantee of the implied legal stability in the long term. Project financing would work well also when the project sponsors are able to put in place long-term take-or-pay contracts for natural gas with a credible and financially strong buyer.

With well designed legislation, regulations and institutions to address the political risk, the host government would benefit in a number of ways: higher project revenues, improved loan terms, the creation of secure markets for goods and services, the import of new technology and training of personnel, employment creation during construction and operation phases, increased tax revenues from participating entities, an improved infrastructure which would have to be developed as part of the project and a saving of foreign exchange.

The Role of Oil Companies

In addition, participation in the equity or debt financing of the project by international and regional banks such as the International Finance Corporation (IFC) or the African Development Bank (ADB) provides additional reassurance to the sponsors and product buyers in the form of the long-term stability of the investment.

Oil majors have internal resources, a wide shareholder base, good credit ratings and diversification to mitigate most risks. For example, in 2012 oil companies have been able to spend about $600 billion in exploration and production (E&P), a 10 percent increase over 2011 and further increases are expected in 2013 and beyond. The majors and national oil companies have financed E&P from their own cash flow, from some debt/bonds, from the stock markets, and from divestiture of their assets. However, increasing demand for funds has increased competition, and put pressure on traditional external sources (bonds, equity, debt). These have become more expensive and scarcer due to new international banking regulations. It is thus important that international oil companies need to have a strong performance resulting in more cash for funding their new projects.

Oil companies could also access institutional funds such as investment funds/pension funds/mutual funds to finance private equity and debt; or they could access emerging external funding sources such as sovereign wealth funds (SWF) and funds in emerging markets. The most active SWFs are Chinese in Hong Kong (in buying bonds), China CIC, China SAFE, Singaporean, and the GCC economies (active in buying bonds). The most active pension funds are Japanese, Canadian, Korean, Chinese and Brazilian. Private banks from emerging markets can also provide funding. These are mainly Japanese, Canadian, and Chinese. Finally, National Oil Companies (NOCs) like the Chinese, Russian and Thai are the most aggressive through merger & acquisition and participation. International finance institutions and development institutions such as the IFC, the ADB, the Overseas Private Investment Corporation (OPIC) and others could provide private equity, debt, and guarantees that could encourage other bodies to invest in the downstream.

Conclusions

At the turn of the twenty-first century, Africa looks set to become a major exporter of energy. Although financing requirements for African infrastructure are large, so are finance options. Private capital, government and oil companies' funds can all be drawn on to develop the region's oil and gas sectors. There are also various risks involved; governments can deal with certain types of risk, for instance regulatory and political risk, while IOCs and other oil companies can take on others, such as exploration risk, in addition to their financial investment. Only through cooperation between the two sides, will Africa be able to maximise its energy potential. ■

Opportunities and Challenges in Africa's Changing Energy Landscape

ALEX VINES believes that East Africa will shift the continent's oil and gas frontiers

Five years ago books on African oil hardly mentioned East Africa. The region was also treated at international oil and gas conferences as the graveyard slot. No longer: today East Africa is the new oil and gas frontier, and Mozambique is the hot prospect with Tanzania not far behind. East Africa shows how quickly oil and gas frontiers shift and how new finds quickly change the way industry investors and analysts treat a region. The back story of African oil and gas is already impressive. Oil reserves in Africa are up more than 25 percent during the last twenty years and gas up by more than 150 percent over the same period.

This is a story of how little has been explored, and how much is still to be found. East Africa is finally on the oil and gas map; compared with some 15,000 wells drilled in West Africa only 500 have been drilled to date in East Africa. Talk of peak oil is dead, partly due to new discoveries. South American pre-salt discoveries in Brazil have been all the rage, but the prospects that this geology continues across to the Gulf of Guinea is significant. Angola far from peaking in 2012 could have an extended life of an additional thirty years as a major oil exporter and could eclipse Nigeria. We need to constantly review our assumptions.

Africa's Changing Markets for Oil Exports …

Changing markets have also impacted on Africa's fortunes. Since the end of the Cold War, the USA, China and others saw African oil as part of an effort to diversify away from too high dependence on Middle East oil. However, over the last decade, the growing demand from Asia, especially India and China has also impacted how African governments look at oil and gas export markets. The figures speak for themselves: the International Energy Agency projects that China will become the world's largest net importer of oil by 2020 and China already receives an estimated one-third of its oil imports from Africa. Angola is the second largest supplier of imported oil to China after Saudi Arabia, (with Iran as the greatest loser) and India imports some 12 percent of its oil from Nigeria.

… changing roles for Asian NOCs

Western IOCs still dominate Africa's upstream markets, helped by decades of political experience as well as technological advantage, but this will change over the coming decades as African states seek to diversify their relationships and strike better deals. Already also Chinese state oil companies are buying out Western independents, or are being encouraged in Beijing to enter into Joint Ventures. We see tie-ups with European IOCs such as BP in Block 18 in Angola with Sonangol Sinopec International (SSI) although US companies seem more circumspect.

There are signs too that Sinopec, CNOOC and others are looking to international best practice to enhance their production prospects. Like western

IOCs they are under pressure to procure more oil, suspect joint ventures such as in Angola are not regarded in Beijing as a sustainable long-term strategy although sometimes seen as necessary for market entry. In the case of Angola, Sinopec and CNOOC would have preferred not to continue working through a Hong Kong-listed joint venture vehicle. In Angola, China has failed to win significant oil block concessions, but instead has locked in oil supplies through oil for infrastructure deals supported by billions of dollars of loans – coined as 'Angola mode' by the World Bank. In 2011, just under 250,000 work visas were issued by Angola for Chinese, the majority for construction workers on these official projects.

Africa's Changing Energy Geography

Yet beyond this politics are some major shifts that are changing the geography of African oil. The emergence of shale gas and oil is a game changer. The USA had been expected to be a significant LNG importer, but today, Qatar, Norway, Russia and West Africa no longer can assume they have a US market. In addition Europe, China and Australia may become major shale gas producers, and this could transform the international market for LNG. Angola, Equatorial Guinea and Nigeria among others need to rethink their gas plans as the market they planned for even five years ago has gone.

They cannot look East either. The massive gas finds along the East African Coast, especially off Mozambique, but also Tanzania make East Africa one of the world's most active oil and gas exploration areas. Reports suggest 250 trillion cubic feet (tcf) of prospective resources in these three countries. International companies like BG, Anadarko, Tullow, ENI and Afren have all had commercially viable finds. The gas story from Mozambique is an 'astonishing exploration success story' and Tanzania is 'impressive' according to Wood Mackenzie. These discoveries could support up to 16 LNG trains but only two train developments have so far been proposed.

The finds in Tanzania and Mozambique are significant but market economics will decide their future. Massive infrastructure investment will be required and billions of dollars of project finance will need to be raised on the international markets to fund it. The hard reality is the breakeven price for development of these new projects but predicting the price currently is near impossible as it depends on projections for the international market price – which includes shale gas developments in China, North America and Australia. This price uncertainty may add significant delays to developing these finds, at a time when domestic expectations of a gas windfall are rising. Mozambican officials speak of first gas to market in 2018, but this looks grossly over-optimistic, as Maputo has not even yet developed a gas master plan.

These gas finds have been followed by oil discoveries in 2012 in Kenya, following already known oil finds in Uganda (since 2006) and South Sudan. Earlier this year President Mwai Kibaki, interrupted a scheduled speech to announce a significant find by Tullow in the country's north-western Turkana region. You could feel his relief as he called it a 'major breakthrough'. Already analysts are warning of the resource curse in East Africa and drawing lessons from oil producers elsewhere in Africa. Ghana is probably the best example to learn from on how its economy and political class is coping with oil discoveries rather than shallow economies like Chad and Equatorial Guinea, or states with a long history of oil distortion like Gabon, Angola and Nigeria.

East Africa poses different challenges. Kenya has a strong agribusiness base, exporting tea, coffee, flowers and vegetables. It enjoys a major tourism industry and Nairobi is a regional hub, providing financial and other services. If significant oil reserves are found, this could be transformative for Kenya's economy. It could also embolden Kenya's ambitions to become a leading regional power. This mood was summed up by a columnist in Kenya's Business Daily who wrote, 'Kenya's economic and diplomatic clout had largely suffered from a lack of known natural resources that are of strategic importance to the rest of the world'. Kenya's politicians will need to keep a close eye on this bullishness, as regional co-operation within the East African Community rather than head-on competition makes better economic sense. Kenya has already been positioning itself to develop regional oil facilities for exports of oil from Uganda and South Sudan. Work started in early March 2012 on building a huge deep-water port in Lamu, to service a pipeline across northern Kenya as part of the Lamu Port South Sudan Ethiopia Transport Corridor (LAPSSET). This aims to foster transport and trade linkages between Kenya, South Sudan and Ethiopia and includes oil pipelines and railway lines and highway from Lamu to Isiolo, Isiolo to South Sudan, and Isiolo to Ethiopia and an oil refinery at Lamu. Finding the $23 billion funding for such a massive infrastructure project is proving to be challenging. The Chinese Government has also signalled that it prefers to see the current oil pipeline from South Sudan to Port Sudan used for South Sudan oil exports and played a critical role in getting both sides to reach an agreement over resuming exports of South Sudanese oil through it.

Prospects for the Regional Economy

East Africa is changing and planning for a future regional economy makes sense. The demographics are likely to change the East African landscape over the next fifty years. Uganda and Tanzania are both forecast to overtake Kenya in population size – Tanzania according to the UN will be the fifth largest country in the world (the fourth being the United States). Kenya with its growing middle class and successful business community should remain as a reliable regional anchor state, although its reputation as a stable democracy took a knocking with the surge of violence that followed the presidential elections in 2008 and threatens to re-emerge.

New presidential elections are scheduled late 2012 or 2013, and oil will additionally raise anticipation of billions of future oil dollars for the victorious. The stakes in these elections have just risen, and the capacity of Kenya's institutions but also of its politicians to gracefully except defeat, is critical. President Kibaki himself will not be running and has a golden opportunity to secure his legacy by ensuring credible and peaceful elections pass.

The greatest worry is that oil money might further blight an already corrupted political class. Kenya has a bad reputation for corruption, especially by its political class. A former anti-corruption tsar, John Githongo fled the country fearing for his life in 2005. He returned to Kenya in 2008 and has set up Kenya Ni Yetu (Kenya is Ours), a campaign aimed at mobilising ordinary people to speak up against corruption, impunity and injustice. If Kenya is to effectively benefit from oil, and avoid the resource curse that many oil producers have experienced it needs to learn from their mistakes.

Although growth in Sub-Saharan Africa peaked in 2007 at 7.1 percent, it is still expected to average 5.5 percent from 2009–12. East Africa is no exception and with growing regional markets and population growth, its leaders should not just focus on external markets for their oil and gas plans but also consider how better to integrate these discoveries into their regional economies. There needs to be a link into the local economy that complements the current development process. Growing agricultural development will require petrochemical markets that Tanzania and Mozambique should look at. Mozambique should consider how to integrate itself further into the southern Africa regional economy because of its increasing energy needs. There is a need for new refineries to cater for domestic needs in East Africa – but this risks becoming a badge of national honour, like national airlines once were, with each country wanting its own.

Lessons to be Learned

The lessons are clear, strengthen independent institutions and oversight, publish all the taxes and royalties from oil, do not rush into prestige projects and extravagant consumption and don't neglect creating meaningful employment. Africans need jobs, but the oil and gas industry itself never employs enough. The key is to use any oil funds to build up a competitive economy. It is also important to remember that most African countries are still net importers of oil: 38 out of 53 and so oil price volatility remains a major challenge and high oil prices have in the past contributed to riots and demonstrations as food and transport prices rose.

But most importantly, governments that have newly joined the oil and gas club need to manage expectation. They should expect lengthy delays before production and expect high sunk costs and long production periods. International investors should also not underestimate the time lags and delays and associated cost and the capacity building needs.

East Africa offers the chance to use newly found oil and gas to enhance regional development and integration and not repeat the mistakes of others. East Africa's political leadership needs to show vision and foresight by being strategic in using these resources to enhance regional infrastructure, diversify their economies further, and invest in education to reduce poverty and create globally competitive economies. Choosing their international partnerships carefully will be part of the challenge. A senior Tanzanian parliamentarian reflected, 'a Chinese consortium offered to provide infrastructure, but wanted in return land, oil concessions and more: it was too much and we allowed the deal to collapse'. When it comes to oil, African states are in the driving seat, they have the agency to decide good or bad deals. ■

Mozambique's Gas Sector: Prospects and Perils

ANNE FRÜHAUF examines Mozambique's current investment climate

A string of recent gas finds off Mozambique's northernmost province has heightened enthusiasm about the area's geological appeal, including vis-à-vis other East African oil and gas frontiers such as neighbouring Tanzania. Mozambique's discovered natural gas reserves offshore Cabo Delgado and Inhambane province now stand at around 130 trillion cubic feet (tcf), compared with Tanzania's reserve estimates of nearly 30 tcf. Mozambique's estimates keep rising, with undiscovered natural gas resources projected upwards of 150 tcf, according to the 2012 draft Natural Gas Master Plan for Mozambique. And the potential for unconventionals such as coal-bed methane is yet to be fully gauged. The budding gas bonanza – combined with the current coal boom – has the potential to fundamentally transform Mozambique's economy, doubling or even tripling its GDP (of $12.8 billion) over the next two to three decades.

In the space of twenty years, Mozambique has transformed itself from a highly indebted post-conflict nation into the go-to place for oil and gas companies of all sizes, as part of a wider East African hydrocarbons boom. The US' Anadarko, Italy's Eni and South Africa's Sasol are key protagonists in the gas space, but many more Western and emerging market players hold stakes. Maputo is abuzz with IOC visitors looking to buy into the bonanza, and telephones are ringing off the hook in the Ministry of Mineral Resources (MIREM). Extractives industry activity is clearly surging, but will the country be capable of absorbing investment on such a large scale?

This article will demonstrate that Mozambique has basic political and regulatory fundamentals in place, especially relative to other East African oil and gas frontiers, including Tanzania. But its politics and institutions may all too easily be overwhelmed by the resource boom. Political, regulatory and infrastructure deficits will likely raise Mozambique's risk profile over time, just as geological risk for investors is declining. This will probably slow the process of bringing fields to production from 2018 onwards, as some developers envisage.

The Big Picture: Political Stability & Macroeconomic Management

Mozambique's political context and macroeconomic fundamentals offer stability, especially compared with many East African neighbours. Like in neighbouring Tanzania, the ruling party Frelimo, which has governed since independence from Portugal in 1975, holds a solid electoral margin, winning around 75 percent in 2009 presidential and parliamentary polls. While in Tanzania an increasingly energised and united opposition poses a growing threat to the ruling Chama cha Mapinduzi (CCM) party ahead of Tanzania's 2015 elections, Mozambique's

Frelimo is unlikely to lose power at the 2014 ballot and may not face a moment of electoral reckoning for another decade. Neither the disintegrating Renamo opposition nor the up-and-coming Mozambique Democratic Party (MDM) is likely to upstage Frelimo for now. Although this dominance of political life and centralised political process hamper transparency, they have also meant a high degree of predictability for investors, akin to the region's oil and gas giant, Angola.

Frelimo's impending presidential succession will generate some uncertainty but does not augur drastic change, especially in policy terms. President Armando Guebuza's term in office expires in 2014, though the September 2012 party congress re-endorsed him as party leader. This could enable Guebuza to manoeuvre a loyal candidate into office, enabling him to wield power behind the scenes, in Putin-like fashion. The succession bears some risk of personnel reshuffles inside key institutions and parastatals, and among Frelimo-associated commercial interests, which are particularly pervasive in ancillary sectors to oil and gas and mining. However, the overall policy trajectory – a relatively investor-friendly framework with a nationalist slant – faces limited risks from the succession.

By and large, Frelimo's unfettered position has supported a large degree of policy continuity and consistent macroeconomic management, closely supported by the IMF and international donors. This has enabled GDP growth averaging 7.9 percent annually between 2001 and 2011 (according to IMF data), sound fiscal management and debt reduction (total debt to GDP stood at 43 percent in 2010, down from 169.6 percent in 2000). Like Tanzania, Mozambique is heavily dependent on donors, which fund around 40 percent of its annual budget. Keen to reduce its dependence on its demanding donors, the government views large-scale gas – and coal – investments as an ideal opportunity to diversify its revenue sources. This should provide government with an incentive to steer a relatively investor-friendly course.

Nonetheless, Mozambique's hydrocarbons boom may increasingly clash with domestic political prerogatives. The oil and coal bonanza has raised political stakes and public expectations. Many are disappointed that poverty levels remain sky-high despite robust economic growth. The 2009 poverty rate of 54.7 percent was virtually unchanged from the start of the decade. Since 2008, two bouts of serious urban unrest in Maputo – and the first unrest targeting a flagship coal operation in Tete province in January 2012 – have reminded government to emphasise the need for inclusive growth. But if Dutch disease pressures associated with the resource boom begin to bite, life will only get harder for ordinary Mozambicans affected by price hikes and an ailing agriculture sector, which accounts for close to 30 percent of GDP and the livelihood for roughly two-thirds of Mozambicans.

"… Mozambique is heavily dependent on donors, which fund around 40 percent of its annual budget"

To defuse discontent, government is emphasising employment creation, skills transfer, and agriculture development. It has set the ambitious target of reducing poverty to 42 percent by 2014, and will be particularly desperate to appease voters ahead of the elections that year. Despite its advantage over the opposition, Frelimo must be concerned by popular disenchantment and accusations that the elite is selling out the country – sentiments that may find expression in voter apathy and opposition advances. Unlike in Tanzania, these gains will likely occur mostly at the municipal level. Increasing social protection (e.g. fuel subsidies) will grow in importance, and all this will leave government desperate to increase its revenue take. Indeed, revenue needs will likely surge faster than gas production and rising coal exports, even though realistically major revenue windfalls from the extractives industries may not be seen before 2020.

Regulatory Gaps

A relatively sound regulatory regime is in place to guide gas investments, and in this area Mozambique is ahead of Tanzania. However, electoral politics ahead of 2014 will overlap with a critical decision-making period for oil and gas, and small yet significant gaps in the legislation could generate uncertainty for investors. The government urgently needs to clarify its broader development agenda for the gas sector and make crucial decisions around infrastructure, local gas pricing, capital gains taxes, CSR standards and social fund payments, among many issues. Without this, officials will struggle to expeditiously conclude production agreements with operators, to ensure production can commence from 2018.

Mozambique boasts a more comprehensive regulatory framework for oil and gas than Tanzania. The Mozambican government has generally pursued a trajectory of incremental regulatory change and adaptation, with the helping hand of the IMF and World Bank. Mozambique's basic regulatory framework is anchored in the 2001 Petroleum Law, which has been followed by supplementary laws and regulations (covering fiscal laws and tax incentives), and model exploration and production concession contracts from 2005. By contrast, Tanzania's basic natural gas policy framework has been long delayed and populist pressures surrounding the extractives industries – already witnessed during mining reforms – might tempt the government to pursue more overtly resource nationalist policies.

At a minimum, Mozambique's communication around impending changes is better than in Tanzania, which occasionally unnerves investors with announcements of contract renegotiations and royalty hikes without divulging any details. By contrast, Mozambique's 2012 draft petroleum amendment law is publicly available and envisages no drastic changes to the hydrocarbons regime. It includes no changes to taxes or the participation of hydrocarbons parastatal ENH in oil and gas ventures (typically 15 percent and capped at 25 percent). Changes do focus on infrastructure, unconventionals, and the provision that 1 percent of gas extracted must be channelled to local communities near the production site. ENH Chairman Nelson Ocuane has hinted that the state-owned enterprise may seek to increase its participation to around 40 percent in future, but financial constraints could hamper such plans. New fiscal laws are also being drafted by the tax authorities however, and moderate tax increases may be implemented over the next couple of years.

One notable gap in the legislation

is provisions for unitisation, which the government will have to fill as projects advance towards production stage. An even more pressing issue is capital gains taxes. The case for such taxes is at best ambiguous, particularly for non-resident companies, but the government is intent on levying taxes to capitalise on accelerating M&A activity. Transactions such as the recent sale of Cove Energy, which has an 8.5 percent share in the highly prospective Rovuma Block 1, have attracted much speculative capital.

In the absence of clear regulations, the government has insisted on negotiated payments, but Mineral Resources Minister Esperança Bias has hinted that the 12.8 percent levy negotiated in the case of Cove is not set in stone. Mindful of the fact that standard tax revenues are years away, government may look to levy capital gains tax fees even above the Cove level, perhaps hoping that further finds will strengthen its hand in negotiations. At worst, this could give rise to uncertainty and even legal disputes (akin to Uganda's dispute with Heritage). But the capital gains tax issue may also bode badly for transparency, given that the payments are not captured under reviews by the Extractives Industry Transparency Initiative (EITI). Mozambique – like Tanzania – is an EITI candidate country, meaning it is not yet meeting all the protocol's standards.

Infrastructure and Cross-border Collaboration

Developing the Rovuma reserves will require infrastructure investment on a monumental scale, as Mozambique currently only has gas production and distribution infrastructure around Sasol's Pande and Temane gas fields further south. The Rovuma finds are expected to warrant the construction of around ten LNG trains and current government estimates suggest investment requirements to the tune of $50 billion. Infrastructure development will pose common emerging-market risks surrounding financing, corruption, and participation by inefficient parastatals and undercapitalised private partners, but strategic development considerations and cross-border challenges may also hamper monetisation of the resources.

While LNG export facilities – centred around Palma (Cabo Delgado) and targeting Asian growth markets as buyers – may hold the greatest commercial appeal, the government's stance on infrastructure could be influenced by national and provincial development imperatives. For example, proposals exist to integrate gas production with economic nodes further south, such as Nacala (Nampula province) or Beira (Sofala province), though their commercial viability is uncertain. Domestic off-take considerations – for industrial use, electricity generation, and fuel and household use – will also be crucial. ENH has received applications to supply natural gas to project developers (primarily for methanol and fertiliser production) that could amount to 2.4 billion cubic feet (bcf) per day.

For Mozambique – and also for Tanzania – domestic energy considerations play a key role in government planning efforts. In Tanzania, the Kikwete administration is looking to natural gas to plug a chronic power generation deficit and address high electricity and transport costs resulting from the high cost of imported fuel. This means that – like Mozambique – the state will look to integrate the development of gas resources with that of broader infrastructure projects, and domestic offtake will be an important consideration for officials.

Similarly, the Mozambican government is keen to increase gas-based electricity production, in light of an impending demand boom from industrial users, a low nationwide electrification rate of 16 percent, and Mozambique's growing significance as a power exporter amid rising demand among Southern African Power Pool (SAPP) countries. All this will increase local demand for gas, including in-kind royalties and local sales. Unlike in Tanzania, however, the government's energy strategy is less exclusively predicated on gas: large-scale projects for hydro and coal-based power generation provide it with a more diversified energy strategy – a fact that could ease pressure on developers.

Cross-border issues could pose additional hurdles for infrastructure development. The creation of an integrated LNG hub for Mozambican and Tanzanian resources might make commercial sense by creating economies of scale. Relations between the two countries are historically cordial, but there has been little official co-operation on natural gas development to date, beyond limited data sharing between ENH and the Tanzania Petroleum Development Corporation (TPDC). The two governments are unlikely to pursue joint development of gas resources unless private investors push the issue. Any such efforts will likely be undermined by competition for revenue and FDI, and massive bureaucratic inertia.

Indeed, cross-border oil and gas issues could generate broader operational uncertainty. Expanding exploration could prompt disputes over borders and resource managements, for example between Mozambique and Tanzania (offshore) and onshore around Lake Nyasa (also referred to as Lake Malawi). The potential for such disputes to escalate, especially between Tanzania and Mozambique, is less serious than in the restive Horn of Africa. But protracted disputes and mediation processes could nonetheless quietly complicate project development.

Conclusion

Overall, Mozambique's geological fortunes have improved tremendously in recent years – faster than those of Tanzania. And there is little doubt that the country possesses some benign fundamentals – political predictability and a basic regulatory framework – that will aid the development of hydrocarbon resources. On the planning and regulatory side in particular, Mozambique is ahead of Tanzania, perhaps by a couple of years. However, the potential perils are equally numerous and may well raise the country's risk profile in future years. Politically, revenue needs will likely surge faster than gas or even coal production. At a time of rising popular disenchantment and failing poverty alleviation upcoming elections in particular will increase pressure on government to hike revenue collection and may also increase social risks around projects. Gaps on the regulatory and infrastructure front could prove yet more challenging. Key issues – including strategic infrastructure and local pricing decisions, capital gains taxes and possible future fiscal changes, CSR standards, lack of transparency and cross-border co-operation – could all conspire to complicate and delay project development and production beyond the 2018 target, when the global outlook for gas prices will look far less certain. ■

Angola's Pre-Salt Provinces – The Next Brazil?

OSWALD CLINT and ROB WEST question whether the resources and economics from Africa's next exploration province will match those of pre-salt Brazil

Industry sources suggest that the Majors spent $3.55 billion acquiring acreage in Angola's pre-salt Kwanza basin in December last year. But will the pre-salt in Angola match the resource potential and economic potential of the Brazilian pre-salt provinces? In this article, we review the geological and economic similarities and differences between these two regions. We conclude that West African pre-salt resources could be significant, especially in the sweet spots, but they will not be as attractive as the Brazilian pre-salt when the economics are considered.

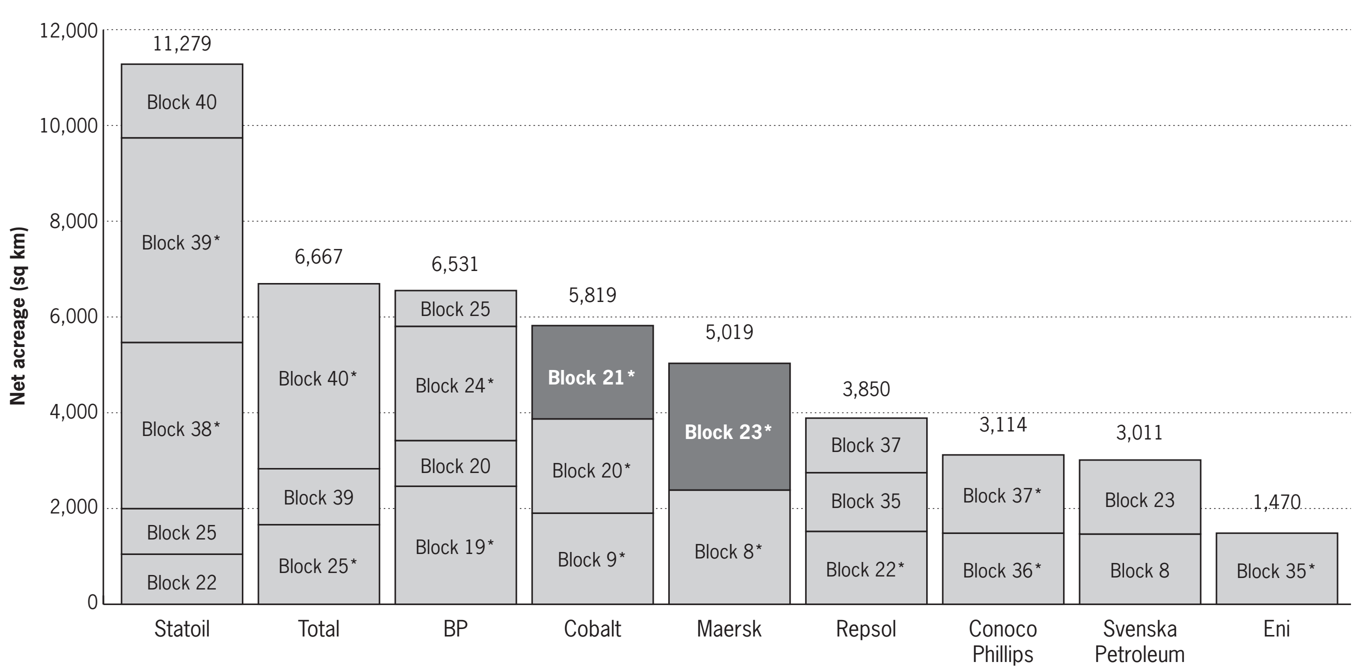
Oil exploration in West Africa goes back to the first half of the twentieth century. Angola and Nigeria's first discoveries were onshore in the late 1950s, although today, onshore creaming curves have levelled off. It was the mid-1960s and mid-1990s that saw the industry's first discoveries offshore in shallow water and deep water respectively. Today, deepwater exploration remains at the frontier in West Africa and it is here that the Integrateds and select E&Ps are focussing their efforts. The USGS recently estimated that West Africa contains 120 bn boe of undiscovered petroleum resources, in addition to 60 bn bbls of proved oil reserves today.

One frontier area that is said to hold the most potential is the Kwanza basin off Angola. 122 million years ago, the Kwanza basin adjoined onto the Campos basin, which is Brazil's largest petroleum province, producing almost 2 mbpd of crude. This suggests geological parallels. The Kwanza basin is thought to be a pre-salt province however, and therefore some have hoped to draw trans-Atlantic analogies with Brazil's Santos basin, the location for the largest ultra-deepwater oil discoveries on record – the super-giant Lula discovery, in the Santos basin's BM-S-11 likely contains c9 bn bbls assuming 30 percent recovery factors. Is either analogy valid? With the Majors' large-scale entry into Angola's pre-salt provinces last year, we are gradually getting closer to finding out.

As stated above, last December, the Majors acquired acreage in Angola's Kwanza basin. Statoil acquired 11,000 sq km of net acreage across five blocks; TOTAL and BP acquired 6500 sq km across three and four blocks respectively, while Repsol acquired 3850 sq km of net acreage across two blocks. Cobalt and BP's Block 20 and Repsol and Statoil's Block 22 lie nearest to the sweet spots, we think. The largest companies' net acreage positions in the Kwanza basin, following the December 2011 licence round, are summarised in Figure 1.

Last December's land-grab also marks another step in these companies' reinvigorated exploration campaigns, with $90 bn spent globally on exploration last year. The group developed a tendency in the late 2000s of avoiding true wildcat exploration, which means that they missed out on cheap access to some of the world's best new plays. The Brazilian pre-salt is a particularly notable consequence of this earlier, limited appetite for exploration. 18.5 bn boe of the 80 bn boe discovered

Figure 1: Acreage Positions of International Oil Companies in the Kwanza basin. Discoveries have been made in Blocks 21 and 23



Source: Source: Corporate Reports, Sonangol, Bernstein Analysis globally since the start of 2010 has been found in pre-salt Brazil. But the supermajors do not hold significant interest in these discoveries. BG Group, Galp and Repsol are the main resource-holders, after Petrobras. BG guide to 22 bn boe of gross resource in their five major Brazilian pre-salt discoveries.

Both Angolan and Brazilian pre-salt basins contain lacustrine source rock and carbonate reservoir systems, originating from rifting in the Barremanian-Aptian, as Africa and South America broke apart. Both also contain thick, early Cretaceous evaporite sequences. But there are also important geological differences, with meaningful implications for resource potential in these two countries, which we have identified using seismic data acquired around Angola's pre-salt provinces. The sweet spots of the Kwanza basin will likely be in its centre, we believe, possibly surrounding Blocks 20, 21, 22, 37 and 38.

Indeed, it is in Block 21, in the centre of the licensed acreage of the Kwanza basin, that Cobalt International Energy's Cameia-1 well encountered a 1180 ft gross oil column, 75 percent net-to-gross pay, no oil-water-contact and vuggy carbonates 'so vuggy you can fit your head inside the pores'. These results are highly reminiscent of the phenomenal resource quantity and reservoir quality of pre-salt Brazil. Likewise, Cobalt believes that a 20 kbpd flow rate could have been achieved without surface-constrained facilities, which is also reminiscent of high, Brazilian pre-salt flow rates.

The Cameia well was drilled in 1682m of water to 4886m. Neither Cameia-1 nor Cameia-2 encountered an oil-water-contact and Cobalt believe there could be further volumes in deeper layers (oil saturations imply a seal is present, but the key risk is how the reservoirs will flow at the deeper levels, given that a flow-test wasn't possible at Cameia-2). The pay figure at Cameia-2 was also only one-third that of Cameia-1, so the appraisal result was not fully positive. But overall, Cobalt is confident the discovery is commercial: a good start for exploration in the basin.

Also promising, Maersk announced that the Azul-1 discovery well penetrated pre-salt targets in Block 23 of Angola's Kwanza basin one month earlier than Cobalt's Cameia discovery, in January of 2012. The well was drilled in 923m of water to a final depth of 5334m. Although it was not possible to conduct a conventional well test, a mini drill-stem test recovered two good quality oil samples. Maersk's interpretation of the data was for potential flow capacity in excess of 3kbpd.

But outside of its more central acreage, geological risks bound the Kwanza basin on all sides. The first is that the carbonate reservoirs in the South of the Kwanza basin may not be as prolific as Brazil's. Indeed, the phenomenal pre-salt carbonates in Brazil's Santos basin have averaged 20 kbpd average initial flow-rates. Even after 6–24 months in production, wells at Lula are at 25 kbpd on average and have exhibited minimal pressure drawdown. These carbonate reservoirs originate from stromatolites spread across a very wide and very shallow shelf in the Santos basin. However, towards the South of the Kwanza basin and in the North of the Benguela basin, the shelf width may not have been sufficient to develop as significant carbonate deposits, according to our seismic data. The transition to depth is much more rapid.

Second, a greater degree of sedimentary overburden may have matured Angola's hydrocarbons to a greater degree and reduced their accessibility in drilling, especially in the North of the basin. Deposition from the Paleo-Congo, to the North of the Kwanza basin, thickened the overlying sediments – and thus increased the temperature and pressure – above the pre-salt areas here. At Cameia, for example, Cobalt encountered a 33 percent gas:oil ratio and oil of 44-degree API. By contrast, the gas:oil ratio in Brazil is lower. We assume just 15 percent in our models, based on data at Lula, and the oil consistently has 28–30 degree quality. The challenges of drilling into Brazil's pre-salt resources are well known, however, the comparable water depths and greater sedimentary burden in the post-salt may complicate drilling in the Northern parts of the Kwanza basin. Notably, even towards the centre of the basin, Azul-1 failed to achieve a production test due to downhole conditions; and more recently Cobalt said a production test result at Cameia-2 had been delayed due to drilling problems.

Third, salt evacuation may have prevented a successful seal in the shallow-water in Angola. From our seismic data, we note that the salt thins materially towards the East of the basin. By contrast, the structure of the Santos basin has thickened the salt layer: unusually, the salt in the shallower-water Santos basin slopes with a 1.7-degree landwards gradient, due to sedimentary loading since the Early Cretaceous. This gradient inhibited downslope sliding of overlying sedimentary strata, leading to salt expulsion in front of the prograding sedimentary wedges plus thrust faulting, which thickened the salt layers. Second the slope of the salt has been linked to a 'buttressing effect', which protected the salt layer during known compressive events. On the other hand, our seismic data shows thicker salt sequences in the Kwanza basin than the formerly adjacent Campos basin across the Atlantic.

Ultimately, the resource potential of pre-salt West Africa can only be determined using the drill bit. But the per barrel economics of new pre-salt Angola discoveries are also likely to be approximately half those of pre-salt Brazil. We model c$5/boe for a new discovery in Brazil, versus $2.5 for a new Angolan discovery, both under $90 oil price assumptions (Figure 2).

The main driver of the lower returns is Angola's PSAs, where entitlement to oil declines with project IRR and the tax rate is higher, at 50 percent. Second, the development of Angola's pre-salt is many years behind Brazil, with most of the majors still in the phase of acquiring seismic data and unlikely to drill before 2013–14. Third, the tight market for FPSOs may hinder rapid development. Fourth, gassier discoveries in Angola could offset the benefit of lighter oil as foreign companies cannot monetise gas under Angola's PSAs: Sonangol retains the resource rights to any gas discovered. Finally, Angola's PSA economics limit the upside resulting from a higher oil price and as projects progress. Brazilian pre-salt projects are approximately 2–2.5x more geared to the oil price. Per barrel NPVs also improve for developments throughout their lives, as the majority of capex is front-loaded. But the uplift in NPV/barrel over our modelled projects' lives is almost 3x stronger for the Brazilian projects we evaluated than the Angolan projects.

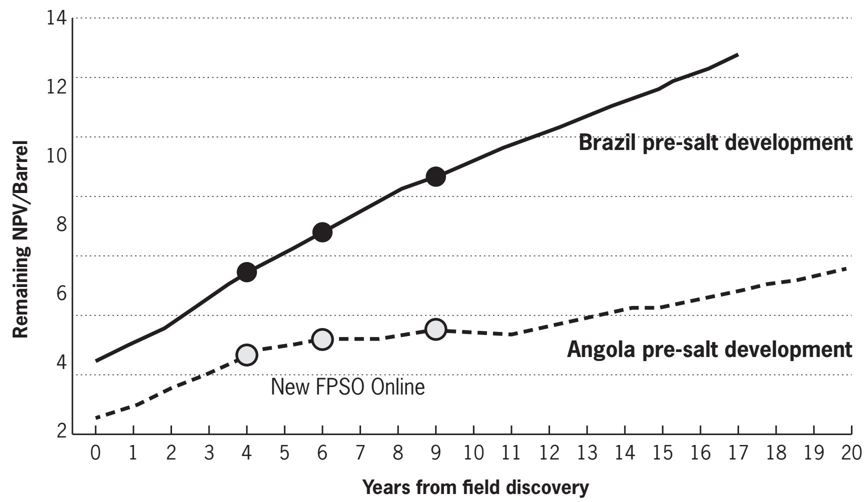
The uplift in NPV/barrel for our modelled Angola pre-salt developments is less than for similar Brazilian developments, even though we assume a faster ramp-up in Angola.

A more economic way to play the West African pre-salt could be through Gabon. Gabon's pre-salt petroleum system is proven, given wells in TOTAL/Cobalt's Diaba Block and by Harvest Natural Resources in the Dussafu PSC last year. Fiscal terms are reportedly '3x better' than Angola and initial NPVs per barrel may be closer to $4/boe we estimate: above Angola, but still below Brazil. Cobalt, TOTAL, Ophir and Tullow will target well results from the pre-salt in 2013, including TOTAL/Cobalt's large Mango prospect.

Therefore, the greatest beneficiaries of Angola's pre-salt potential may be Angola's fiscal position, world oil supply, and only secondarily upstream companies themselves. Nevertheless, large discoveries at low NPV/barrel multiples, are still clearly significant. Our base case forecasts, for Angola's oil production by 2020 are for a 0.6 mbpd increase, from 1.7 mbpd of production this year. Success in Kwanza basin exploration could re-ignite the pace of discoveries and bolster longer-term production potential. The results would be beneficial to global oil supply, with reliance on OPEC already set to grow by 8 mbpd out to 2020, under our forecasts.

It is still very early days for pre-salt Angolan exploration. The key answers are ultimately dependent upon results at the drillbit. However, we have reviewed the likely geological and economic similarities and differences between pre-salt West Africa and pre-salt Brazil. We conclude that the geology of Angola's pre-salt play in the Kwanza basin looks promising by analogy to the Brazilian pre-salt and the first exploration well results from Cobalt International Energy and Maersk Oil. But the distribution of resources throughout the basin is not yet certain, and there are key risks in particular areas. Angola's PSA structure also limits resources' value to explorers, so resource discoveries will need to be larger for the prize to 'move the needle' as much in economic terms. After Angola, the industry will move to the next pre-salt province. Gabon could also be promising, given a superior fiscal regime reportedly 3x less punitive. Hence the days of West African exploration and investors' focus on the region are far from over.

Figure 2: Remaining NPV/Barrel Profile over Development Life of Brazil and Angola Pre-Salt Projects



Source: Company Reports, Bernstein Estimates

Brazil and Uganda: Government Intervention and Oil Development Prospects

EDUARDO PEREIRA and ELISON KARUHANGA explore the effect of government regulation on Uganda's and Brazil's upstream prospects

Brazil and Uganda have very similar petroleum industries. Both countries announced one of the largest oil discoveries in the last decade. Brazilian pre-salt discoveries proved the existence of large reserves which could lead to several billions of crude oil to be exploited. Uganda's discoveries involve more than a billion barrels with the potential for more additions to current proved reserves in the future.

Although Brazil has produced oil for a relatively long period of time, it was never self-sufficient, until production was ramped up in 2006. Still today, Brazil's production is relatively small, both in a global perspective and in the context of the size of the country's reserves. Uganda in turn never produced oil in its history. Both countries hence find themselves in a similar situation aiming to develop their oil industries in order to significantly shape their economies in the coming decade.

In this article, we look at the similarities and differences in the two countries' development approach towards their upstream sectors, with a focus on legislative changes made after the significant discoveries. Our two main conclusions are (i) Brazil's more established oil sector is likely to move forward faster than Uganda, and (ii) both countries are losing valuable time by debating legislative changes in view of nationalist rather than primarily economic objectives.

The Brazilian Case

Brazil opened up its upstream market in 1995 with the constitutional change of Petrobras' exclusive right to explore and exploit oil and gas reserves. Two years later the government approved the petroleum law, which created the national petroleum agency ('ANP'). This body had responsibility to regulate and monitor the petroleum industry.

One of the major roles of the ANP is to prepare and organise license rounds.

This represents a significant change from the monopoly regime. The system allows private parties to compete at the same level as Petrobras for new blocks. The first bid round occurred in 1999 and every year ANP would promote a new round to encourage more exploratory work. At that time less than 3 percent of the sedimentary basins had been explored in the fifth largest country in the world. The government was keen to open more blocks and to attract more investments in the upstream sector.

The bid rounds were very successful until 2006 by which time a large variety of players were engaged in the upstream sector, including IOCs, NOCs, independents, local and foreign players. Changes to previous plans for Brazil's upstream sector and its legal framework occurred, however, following the 2006 discovery of what then was seen as possibly large pre-salt reserves. The area is located off the coast of Rio de Janeiro and Sao Paulo and below the salt-layer (i.e. thousand of metres below the sea level). Such discoveries clearly affected the stability and periodicy of the license rounds. More precisely, license round 8 was never concluded, license round 9 excluded some pre-salt areas, and license round number 10 only offered onshore areas. The national interest was clearly behind these decisions as the government was studying and considering a new regime for the pre-salt area.

Moreover, after several years of studies, the Brazilian government decided to replace the license regime by a production-sharing regime. This was another radical change as the license regime had been quite successful after ten bid rounds. However, the key difference is that the license regime was not extinguished but only replaced for the pre-salt area and strategic areas that could be determined in the future. It is important to note that less than 30 percent of the pre-salt area has been awarded and it represents far less than 10 percent of the size of the country. Consequently, the government can continue to issue license rounds outside the pre-salt area (e.g. tenth licence round).

For now, the petroleum industry in Brazil can continue to attract investments as there is no legislation or political movement against offering new areas outside the pre-salt area. However, the indication that a new petroleum law would regulate the distribution of royalties between governmental authorities created unnecessary uncertainty for the petroleum industry. Although this is purely a governmental matter, it is affecting the private sector as the eleventh license round has been delayed for it is not clear whether the new royalty rules will affect only the governmental distribution or if it will increase the private contribution (currently fixed at the maximum of 10 percent for royalties). As long as the governmental authorities cannot reach a reasonable solution to share the future income from the hydrocarbons production, the private sector simply waits. This legal uncertainty has seriously affected Brazil's petroleum industry in the past years, particularly in the pre-salt area. The technical and logistical challenges are high so it is necessary that large investments be attracted to reduce the costs and increase the technical capacity to bring those reserves to the stream.

It is possible to affirm that the political, public and media pressure has clearly harmed the development of pre-salt areas. Since 2006, no other pre-salt block has been offered in any bidding round. The planned PSA regime has never been completed for Brazil's politicians are fighting over the distribution of future revenues as if they were an immediate cash flow. The pre-salt projects should take years of investments before they become fully operational and produce oil to its full capacity. In addition, it is necessary to verify how the cost recovery will be determined as this might delay even longer the profit split and the government take from these areas.

The legislative changes in the petroleum regime were not focused on a risk–reward scheme as announced by the government. If the pre-salt geology favored investment, then higher fiscal terms could be imposed in the industry without any big 'fuzz' and with simple adjustments to the existing regulations. Thus, the political background clearly determined the necessity to change the structure of the petroleum regime so that higher intervention could be arranged and more participation of state companies.

The Ugandan Case

Uganda is estimated to have 2.5 billion barrels of Stock Tank Oil Initially in Place (STOIP) and an estimated 1 billion barrels of recoverable reserves of oil and gas. The discovery is located around the Albertine Graben in the most northern part of the western arm of the East African Rift System. It is close to Uganda's northern border with the Republic of South Sudan and its western border with the Democratic Republic of Congo. The Albertine Graben is divided into eleven exploration areas. Uganda is landlocked and the closest coastline is the port of Mombasa in Kenya approximately 1200 kilometres away. Due to this distance, the transportation of oil and gas to the coast poses an infrastructure challenge.

There is also the need for a secure supply of energy. Uganda relies exclusively on Mombasa for its access to imports and especially petroleum imports. It takes on average 22 days for cargo to reach Uganda from the port at Mombasa. So Uganda's infrastructure challenge is heightened by the desire for a secure supply of energy products.

In addition, the Albertine Graben is an ecological treasure chest. Over 50 percent of birds, 39 percent of mammals, 19 percent of amphibians, and 14 percent of reptiles and plants found in mainland Africa are found in this region. Therefore, maintaining the ecological diversity of the Albertine Graben and simultaneously exploiting the hydrocarbon resources is of paramount importance.

Originally, the geological, political, ecological and infrastructural risks made Uganda unattractive to investors seeking to explore upstream opportunities. Despite the attempts of the various governments between 1938 and 2006, only two exploration wells were drilled. The current government was able, to its credit, to attract investment in the prospective region and the results of the various Production Sharing Agreements have been discoveries that would place Uganda among the top fifty producers in the world.

The aggressive exploration activity carried out between 2006 and 2009 by Tullow Oil and Heritage Oil and Gas established a working petroleum system with a success rate of 90 percent of hydrocarbon potential from the wells that were drilled. It is important to note that only 30 percent of the Albertine Graben has been explored and that is just one of five sedimentary basins in Uganda. The others remain totally unexplored.

Since 2006 the Government has not

entered into any new agreements or held a bid round. The stated concern of Government is to have the necessary laws in place before any licensing can occur. It is also interested in developing both the midstream and downstream infrastructure to ensure the availability of petroleum products in the country. Thus it has presented three bills to Parliament for enactment. One deals with the upstream sector, one with the midstream sector and the third with Revenue Management.

Exploration in Uganda has raised excitement and stirred national debate and political contestations. The term 'resource curse' has gained particular prominence in public discussions. Members of Parliament, civil society and national and international NGOs have all made robust contributions to the debate. The Government is being challenged to be more transparent and there is also a strong demand from certain Members of Parliament to give Parliament an oversight role in managing the petroleum sector. The cultural and traditional institutions around the Albertine Graben are also demanding up to 15 percent of gross oil revenues when the oil starts flowing. The political disputes and debates on how to manage the oil sector in Uganda have led to a freeze in the award of new licenses.

In opting to have the legislation in place before any further licensing rounds, the Government has decided to resolve and settle the political issues or at least to have the questions opened up and explored. As at the time of writing, the Bills are still with Parliament. The Parliamentary process has been long and drawn out. In accordance with the Rules of Procedure of Uganda's Parliament after the Bills were presented to the House they were then referred to a parliamentary committee for scrutiny. The committee first required basic training in oil and gas law. Many civil society actors, international NGOs, academicians and industry players presented the concerns they had with the Bills to the committee, which thus became the centre of political contestations regarding the Bills. Even traditional and religious leaders presented their views on the Bills. Therefore, Parliament has the task of making law. In respect of oil and gas, it must first appraise itself on the basic terminology. As a result, the law has been delayed. The committee is expected to report back to Parliament in the first week of September.

It is submitted that the actions of the Government of Uganda and the debate in the country should take cognizance of developments occurring in the East African region. Significant exploration activity is happening in Kenya, Tanzania, Ethiopia, Mozambique, to mention a few. Uganda is competing with her neighbours for investment capital as they are all net importers of capital. In looking to create the best laws Uganda should not forget a cardinal rule of commerce; time is money.

Conclusion

It is clear that the Brazilian and Ugandan authorities desired to maximise the government take from their new and highly profitable prospective reserves. This is an understandable approach, as they must ensure that the legislation in place provides a fair compensation for the government in relation to the related risk-reward. However, it is important to remember that neither Brazil nor Uganda is comparable to countries like Norway. They cannot afford to spend years discussing what to do with their natural resources, nor to put aside most of their income from the petroleum industry in a reserve fund for future generations. Both countries require investments on the ground to increase their GDP, develop their poor infrastructure, provide more jobs, increase the knowledge of their hydrocarbon reserves, and the like.

Uganda adopted a harsh approach as no block could be offered until the new legislation had been approved. Brazil took a gentler approach as the new legislation focused on a specific location so that the remaining areas were not affected. However, both countries face difficulties to balance the interests of the parliament, media, civil society and the petroleum sector. Nevertheless, it is quite clear that their decisions delayed investments and exploration on their territories.

It is of course important to strike the right balance between the protection of natural resources and developing the economy as both deal with public interest. But what is paramount is that the petroleum industry involves a long process between awarding a block and producing oil and this is particularly true for both Brazil and Uganda. Since it might take several years to start a proper cash flow from an oil and/or gas field, all the parties involved should focus their time and energy to solve the matters in the short term rather than speculating about future income and dealing with problems in a theoretical and inefficient manner. ■

Nigeria: A new dawn?

AMRITA SEN believes Nigeria's oil production looks set to continue to grow poorly

'Let's say there are prospects for a new Nigeria, but I don't think we have a new Nigeria yet.'
Wole Soyinka

Despite being the largest oil producer in Africa, Nigeria has been in the limelight over the last decade for all the wrong reasons. Beginning in the late 1990s, the cosy relationship between Big Oil and a despotic Nigerian state was challenged by popular, and increasingly militant, pressure from local communities, or more properly from armed youth movements. The shift from non-violent protest to militancy, and ultimately to armed struggle, was in many respects the inevitable result of the Nigerian government's brutal repression of the Ogoni movement. A decade later, the Niger delta is home to a fully-grown local insurgency. While sporadic episodes of violence and attacks on oil facilities have always proved an inherent feature of the Nigerian oil sector, the problems have escalated dramatically since the election cycle of 2003.

In late 2005, a new and well organised militant group the Movement for the Emancipation of the Niger Delta (MEND) exploded out of the creeks of the western delta promising to close down the oil industry. Since then, the increased frequency of the attacks translated into a growing chunk of production capacity exiting the market. After reaching a peak of 2.45 mb/d in October 2005, Nigerian production fell steadily through to 2009, touching a low of 1.7 mb/d in mid 2009, despite Nigeria's nameplate oil production capacity being around 2.9 mb/d. Companies declared force majeure on a regular basis and key facilities that were shut down in early 2006 repeatedly failed to resume operations according to schedule. Tentative restarts usually proved ineffective as poor security in the region continued to hamper repairs and prevent the normal flow of oil through the country. Indeed the Nigerian oil production outlook cannot be easily linked to particular events affecting individual oil installations. The return of a facility was normally followed by the downing of another, as attacks continued to make the output flow from the country increasingly unsteady.

Following years of negotiation, in October 2009, MEND declared an indefinite ceasefire under the government's amnesty programme. Although the militants have threatened to end the truce from time to time, in general there have been fewer attacks on oil installations than in the pre-ceasefire period. The ceasefire has also enabled some companies to repair damaged oil infrastructure, allowing Nigerian production to climb back above 2 mb/d since 2011.

Yet today, Nigeria is the world's capital of oil theft. The Minister of Finance, Dr. Ngozi Okonjo-Iweala, puts the figure of oil theft and illegal bunkering at 0.4 mb/d, which equates to around $40 million lost per day (or around $15 billion annually) at a price of $100 per barrel. Others put the estimate lower, but still staggeringly high. According to Shell, Nigeria has been losing about $5 bn annually to the activities of illegal oil bunkerers operating in the oil fields located in the coastal parts of the country due to the loss of an estimated 0.15 mb/d of oil output. Crude oil theft has degenerated from the occasional and haphazard operations of some local thieves to a well-coordinated syndicate of criminals who are prepared to do anything to obtain the crude oil, according to officials. An increasing number of canoes, barges and illegal refineries are visible all over the coastal area these days. The Joint Task Force in the Niger Delta recently reported that it had destroyed 3778 illegal refineries and seized eight vessels, 120 barges, 878 Cotonou boats, 178 fuel pumps, 5238 surface tanks, 606 pumping machines and 626 outbound engines allegedly belonging to oil thieves in the first quarter of 2012. Despite the efforts, oil theft is on the rise in Nigeria, playing a significant role in taking production in September down below 2 mb/d for the first time in over a year. Shell has declared force majeure on its Bonny Light crude exports several times this year due to illegal bunkering on the Nembe Creek Trunkline.

But oil theft is only a part of a wider industry problem. The oil industry is characterised by wastage, corruption, low productivity and unchecked dominance of foreign multinationals. Many commentators allege that high-level politicians, former and serving military officers, militant leaders and former workers of oil companies are all complicit. This makes a crackdown on oil theft almost impossible, as the Government simply does not have production figures and has to rely on export numbers. In the absence of production data, companies currently pay taxes and royalties based on available export figures and not production figures as stipulated by law. Further, in terms of know-how and upstream technology, the initiative still remains with foreign multinationals and local contribution is abysmally low.

Gas flaring is another significant issue, with areas near Port Harcourt particularly impacted, and for many, it underscores the failure of upstream operations. According to World Bank statistics, more than 150 billion cubic metres (bcm) of gas are flared and vented annually around the world and Nigeria leads that list. The annual 35 bcm of gas flared in Africa alone is equal to half the continent's power consumption. Considerable attention has also been drawn to the environmental damage caused by oil spills in the Niger Delta. According to the Nigerian National Oil Spill Detection and Response Agency (NOSDRA) approximately 2400 oil spills were reported between 2006 and 2010 as a result of sabotage, bunkering and poor infrastructure.

Then there is Nigeria's National Petroleum Corporation (NNPC). NNPC's financial situation has been a long-standing constraint for the country's oil industry. The funding problems of the state-owned company have been well documented and its inability to meet its cash obligations to IOCs in a period of heightened liquidity constraints has added further impediments to the country's growth. Corruption was rife among members, with a KPMG Report in 2010 detailing the manipulative opacity, deliberate duplicity, self-inflicted inconsistencies and corruption within the NNPC network. As a result, oil companies were severely lamenting that NNPC was underfunding projects. In July this year, the board of NNPC was completely revamped, but it is too soon to tell whether this will herald a new era for Nigeria's oil industry.

Last week, President Goodluck Jonathan presented a $31 billion budget to parliament for 2013, which assumed total oil production of 2.53 mb/d. Even if one includes NGL output, Nigeria will struggle to reach 2.5 mb/d by next year. Despite the amnesty programme and various steps taken in the right direction, tackling the deep structural problems facing the Nigerian energy sector will require firm and decisive leadership in Abuja.

Within the oil sector itself, the current laws governing the oil and gas sector are obsolete and have failed to address many current issues. The Petroleum Industry Bill (PIB), which was first presented to the National Assembly in 2008 is yet to become a law and is holding back some $40 billion worth of investments in the oil sector. The federal Government recently sent a new version of the bill to the National Assembly after the previous copy was rejected yet again by the Sixth National Assembly. But there are still contentious issues in the new draft. Shell thinks the tax terms in the new oil bill are so uncompetitive that they risk rendering offshore oil and gas projects unviable, as the Government now intends to raise its stake in deep offshore blocks from 61 percent to 73 percent. Many suggest that the bill has taken away all the good provisions such as incorporated joint ventures recommended in the old version that is capable of turning Nigeria into an oil production state.

Thus, the start-up timing of planned upstream projects remains in doldrums.

Although Total managed to start up the 180 thousand b/d Usan field in February this year, the start-up of the remainder will depend heavily on the PIB and the fiscal/regulatory terms it imposes on the oil industry. Most of these projects have already been delayed several times. Thus, current and future performance of the Nigerian oil sector remains ultimately and intimately linked to the evolution of the structural problems affecting Nigeria's oil producing region – poverty, poor governance and proliferation of weapons. In the absence of a clear shift in the current dynamics, which seems unlikely at present despite the recent changes in the oil sector, Nigerian oil production is set to continue to perform poorly.

Phasing out Fuel Subsidies in Nigeria

ADEOLA ADENIKINJU argues the case against fuel subsidies in Nigeria following last year's unsuccessful reform

Subsidies on petroleum products remain one of the most contentious socio-political economic issues in Nigeria. It is an issue that generates very strong emotions across the country's ideological and political divides. Every successive government since 1986 has tried to eliminate or at least reduce fuel subsidies for largely fiscal reasons, and public reactions have remained the same: violent opposition, nation-wide strikes, sometimes resulting in death and destruction of public properties.

I have always believed that subsidies on fuel, especially on gasoline, are a wrong economic policy. The socio economic costs have been high. Our experience in the past three decades has shown that everybody in the chain loses – consumers, producers and the government. Sporadic fuel shortages, resulting in long queues at fuel stations across the country, sometimes lasting several weeks at a time; the emergence of black markets; and fuel adulteration are some of the costs that consumers have had to bear. Consumer and producer welfare losses (deadweight losses) as well as huge fiscal revenues foregone by reduced exports by the government are some of the negative outcomes of the fuel subsidy regime. This is apart from the collapse of the downstream petroleum infrastructure due to lack of funds to maintain them and the dearth of private investments in refineries and related value chain in the oil industries as a result of the uncertainties that fuel subsidy has generated; and Nigeria's shift from being a net refined products exporter to the largest importer of refined petroleum products in Africa.

Background to the 2012 Fuel Subsidy Reform

On 1 January 2012, the government of President Jonathan announced the total removal of gasoline subsidies. The previous administration had successfully removed subsidies on diesel in 2007. That administration had also issued a Presidential Directive in June 2009, to the national oil company, the Nigerian National Petroleum Corporation (NNPC) to stop subsidising kerosene. However, the NNPC chose to ignore the later directive.

President Jonathan was simply following the path of the previous administration in its unsuccessful efforts to remove all of the country's fuel subsidies. The fiscal costs of Nigerian fuel subsidies have become intolerable in recent years as the four domestic refineries with combined capacity of 445,000 barrels per day (bpd) became degraded due to lack of timely Turn Around Maintenance (TAM) and direct sabotage on them. The combined capacity utilisation of the refineries decreased to an average of 20 percent, forcing the country to turn to large-volume fuel imports to meet domestic demand. The country's import and storage facilities at the ports were never designed for such large-scale fuel imports.

Until 1973, petroleum products prices were in fact largely market determined. Then the country had only one refinery that was jointly owned by the government and Shell but was managed by Shell. The refinery located in Port Harcourt operated efficiently. Prices differed across the geopolitical zones of the country based on geographical distance from Port Harcourt, as did the amount of sales tax imposed by the different regions. However, by 1973, the government took over the management of the refineries and imposed uniform prices for petroleum products across the country. The intervention of government in the fuel market in 1973 can rightly be pinpointed as the beginning of the crisis in the downstream petroleum sector in Nigeria.

The government's deliberate objectives to intervene in the market were based on several factors: (a) to promote rapid industrialisation (b) to promote balanced regional development, (c) to control inflation, (d) and to share the benefits of oil ownership among its citizens.

However, over the years, the evidence does not corroborate that these objectives have been achieved. Low fuel prices have not led to rapid industrialisation. The share of manufacturing value-added in GDP has on the contrary declined from a height of 8 percent in 1977 to less than 4 percent in 2011. Fuel also accounted for less than 5 percent of production costs in Nigeria. Neither has the policy achieved its goal of balanced regional development. Significant differences in the level of developments exist between the North and the South. Residents in locations outside the South West buy fuel at prices above the official prices. Furthermore, inflation in Nigeria has been driven primarily by monetary accommodation of fiscal excesses. Finally, the benefits of subsidy have not been equitably distributed across income groups, and locations. The rich and the urban dwellers have appropriated a larger share of the subsidy compared to the poorer and vulnerable segments of the population.

Fuel subsidies have increased significantly over the years, especially with the rising share of imports in domestic supply: from $470 million in 2002 to $2.36 billion in 2007 and to $4.46 bn and $13.46 bn in 2010 and 2011 respectively, with a rising share of GDP from 1.3 percent in 2007 to 4.1 percent in 2010 and 8.1 percent in 2011. The costs of subsidies on the fiscal capacity of the various levels of government are significant. Oil revenue accounts for over 75 percent of government revenues in Nigeria. For states and local governments, the percentage is as high as 95 percent in some instances. High subsidy levels in recent years have placed some limitations on the capacity of governments at all levels to deliver so-called 'dividends of democracy' to their citizens. Fuel subsidies in 2011 amounted to twice the share of federal government capital expenditure. Total fuel subsidies were 1.5 times larger than total revenues of all the 774 local governments and 93 percent of their combined total capital expenditures between 2006 and 2011. It was 76 percent of revenues of the 36 states governments in 2010.

The 2012 Price Review: Dealing with the fall-out from the subsidy protest

On 1 January, the Petroleum Products Pricing Regulatory Agency, PPPRA, announced the full deregulation of the fuel market. This led to an immediate increase in the price of gasoline from $0.42 per litre to $0.90 per litre. The immediate cause for the deregulation was the spiralling of subsidy payments and the vast fiscal pressures on the government, especially following the increase in the national minimum wage from $48.3 to $115.9 per month shortly before the 2011 national elections which further increased fiscal pressure on many local governments.

The events that took place after the announcement of the subsidy removal were quite interesting and showed a classic game between the government and labour unions. On 3 January, the labour unions announced they would meet to determine an appropriate response to the subsidy removal. On 5 January, the government formally endorsed the Subsidy Reinvestment and Empowerment Programme (SURE-P) under which a list of projects and programmes would be implemented. On 7 January, the President addressed the nation for the first time indicating there would be no reversal in the deregulation policy and announced a number of policies and programmes that will be implemented including rail projects, mass transit, youth employment, and so on. He directed all Ministries, Departments and Agencies of government (MDAs) to embark immediately on all projects that had been designed to cushion the impact of the subsidy removal in the short, medium and long term as outlined in the SURE-P document. On 9 January, the labour union supported by a large number of civil society organisations started a nationwide protest. On 16 January, the federal government after a series of meetings announced a reversal of full deregulation and reduced the price of gasoline to $0.61 per litre. In his 16 January broadcast, the President announced a reduction of 25 percent of basic allowances of all political leaders, a review of the number of government agencies with overlapping responsibilities so as to reduce recurrent expenditure. He promised that the legal and regulatory regime for the petroleum industry would be revised to address accountability issues and current lapses in the industry. The Petroleum Industry Bill, PIB, is the vehicle to achieve this objective. Labour soon called off the strike actions.

On 13 February, the federal government inaugurated the committee to monitor its share of savings from the partial subsidy removal on fuel. The government began to publish monthly the amount of payments to all the three levels of government from the subsidy saving fund. On 21 February, the President announced that the SURE-P programme would have to be reviewed, as the envisaged amount from full subsidy removal is no longer realisable.

Lessons from the 2012 Price Review

The response to the 2012 not fully successful reforms of the fuel market brought about a number of lessons. First, the preliminary efforts to engage the society on the need for fuel reforms were not properly handled by the government. Most Nigerians, who had travelled home for the annual Christmas and New Year holidays, were also not prepared for the timing of the fuel subsidy removal.

Second, investigations carried out by an Ad hoc Committee of the House of Representatives confirmed the fear of most Nigerians that the subsidy regime was a racket and fraud. Among the Committee's key findings were the following:

(i) The relevant agencies in the downstream industry under the Petroleum Support Fund (PSF) scheme failed to keep reliable information. Data supplied by the various agents on petroleum consumption, imports and amount of subsidies actually paid showed wide variations. For instance, the Central Bank of Nigeria (CBN) figures showed that $21.60 billion was paid as subsidy between 2009 and 2011, the period covered by the probe. Figures submitted by the PPPRA and the Office of the Accountant General of the Federation (OAGF) were $16.28 billion and $18.46 billion respectively. However, reconciliation of figures submitted to the Committee gave a figure of $29.89 billion.

(ii) The Committee alleged that 22.2 percent of fuel claimed to have been discharged for 2011 was actually over invoiced volume.

(iii) There was a multiplicity of institutions and government agencies. Over 14 agencies were directly or indirectly involved in fuel import and subsidy importation in Nigeria. Theoretically the process is supposed to be fraud proof as there are nearly 18 approvals that must be obtained from different agencies before subsidy payments are made. However, in reality, this process was heavily compromised.

Third, the private sector responses to the price increases were muted and not as drastic as was feared. We monitored prices of commodities and transport fares in selected locations over a period of about six weeks after the price change in January. We compared prices before the fuel price change and six weeks later. Our general finding is that the initial price reactions were generally much higher than the final prices for the selected commodities and transportation services. Initially supply prices were not sustained. Over time, prices settled at levels above the prevailing price levels before 1 January 2012, but much lower than the initial price increases that followed the subsidy removal. Generally, for many of the commodities price increases rose between 0 and 28 percent with a mean of 13 percent after six weeks. However, transportation fares were more responsive to the increase in fuel prices and the mean change in transport fares was 30 percent.

Fourth, the impacts on households' welfare vary. The results of the welfare impacts of the price increase on households

Table 1: Impact of the Subsidy Reduction on Different Categories of Ibadan Households (in Naira).

Groups	Mean monthly Income	Mean expenditure on fuel	Share of fuel expenditure in hhld income	Compensating variation	CV/Income
Total Households	107,189	9,357	8.73	4,576	4.27
Low income households	50,192	3,965	7.90	1,952	3.89
Middle income households	147,018	11,832	8.05	5,789	3.94
High income households	309,875	12,425	4.01	6,099	1.97

Note: the exchange rate is N158.43: $1.

Source: F.N. Osagu, 'Phasing out Petrol Subsidy in Nigeria', 2012.

in Ibadan city, one of the largest cities in Nigeria, are shown in Table 1. This shows that the low income group spend a much higher proportion of their income on fuels compared to the rich and would need a much higher compensation to mitigate the effect of the subsidy removal.

Fifth, the results of the impact study on households' perception of the fuel subsidy were quite instructive. 55 percent of the respondents claimed that the concept of fuel subsidy was not totally clear to them, 82.9 percent claimed that transportation fares have increased after the fuel price increase, 88 percent claimed that prices of commodities have increased, 35.7 percent agreed or strongly agreed that the benefits of fuel subsidy accrued more to high income households, only 39 percent agreed that reducing petrol subsidy would free more resources for government to fund development projects, 54.2 percent claimed that the rate of petrol usage has dropped since the adoption of the policy. 71.8 percent of the respondents agreed that governments should have adopted good welfare policy before embarking on petrol subsidy reduction.

Policy Implications and Conclusions

Most Nigerians have come to the realisation that the country's current fuel subsidies regime is no longer sustainable. The central arguments against subsidy removal are broadly two: first, how to compensate potential losers? The second major factor is the distrust of government and the huge credibility deficit of successive governments. Governments have not kept to past promises to use proceeds from past reductions in subsidies to build new infrastructure or improve the living conditions of Nigerians. The handling of the last subsidy deregulation in Nigeria by the government was undoubtedly poor. The fall-outs from the event have foisted on the government the importance of transparency, and due process in the management of the downstream. The PIB, currently before the National Assembly, if passed will provide a legislative backing for full deregulation of the downstream sector, enhance the oversight functions and streamline the agencies in charge of the sector, it will also bring transparency to the management of the oil sector.

The intervention programme SURE-P, introduced by the government along the lines of Ghana's parallel reform programme, was not seen as a well articulated or designed programme that could make a significant mitigating impact on the poor and the vulnerable groups. The absence of credible data for the poor makes income transfers almost impossible to implement. Local governments, unlike the federal government, have not even been forthcoming on how their shares of the income from the subsidy reduction are spent to alleviate poverty and improve infrastructure in their jurisdiction. Lack of accountability will no doubt hinder the ability to implement successful deregulation of the sector without significant opposition in the future. ■

The Sudanese Struggle for Stability: Long-term Energy Security Hinges on Deeper Bilateral Political Progress

BILL FARREN-PRICE looks at the prospects for a resumption of oil exports from Sudan and South Sudan in the wake of September's peace agreement

The fledgling nation of South Sudan has had a tough first year, confronting head-on the realities of its geopolitical and economic reliance on its northern neighbour, Sudan, for access to international oil markets. South Sudan shut down oil production in January, following a dispute over tariff payments to Khartoum. September's peace agreement brokered in Addis Ababa has, on the face of it, laid the groundwork for a resumption of oil production and exports from the south. But traditional lifters of Sudan's high-quality crude will be as concerned with the sustainability of a resumption of oil exports as with the restart itself.

While both Sudan and South Sudan are for now bound together by their overlapping oil industry, a resumption of production from South Sudan and export via the north will be sustained only if there is further progress in bilateral discussions between the two countries over unresolved issues, in particular the future of Abyei and other disputed territories. Despite the improved diplomatic atmosphere between the two Sudans evident at a recent investment roadshow in Vienna, the narrowing of the political gulf between the two countries has been driven by the economic imperative of restarting oil exports, on which both are so reliant for state revenue. Juba's desire for economic independence will ultimately limit this marriage of economic convenience, while failures to contain rebel uprisings in Sudan's southern states could also put the industry in fresh danger.

This year's oil shutdown means that Khartoum and Juba have now experienced the challenge of maintaining currency stability and public spending after months of shuttered oil exports – and the experience has pushed both sides back together. South Sudan should be able to restart some oil production relatively swiftly once technical problems are overcome, but long export pipelines through Sudan are vulnerable to disruption, especially if fighting in the border zones, such as that seen in South Kordofan in recent weeks, continues. Achieving pre-crisis production levels of 450,000 b/d will be a challenge for the two Sudans if the Sudan People's Liberation Movement – North (SPLM-N) continues its campaign in Sudan's southern states and if Juba and Khartoum do not make progress beyond the September peace deal.

More Realistic Budgeting

Government officials are cautious about the oil restart. Sudan's Finance Minister Ali Mahmoud has said that projected revenue from the recent deal with South Sudan over oil transit fees will not be reflected in the 2013 budget, suggesting Khartoum is wary of delays to restart timelines. Before the early-2012 shutdown, South Sudan produced 340,000 b/d, of which 250,000 b/d derived from the Melut Basin Petrodar project and the rest from Blocks 1, 2 and 4. Sudan had assumed transit fees income of $36 per barrel in its original 2012 budget, but the collapse in revenue and the September agreement have encouraged a more realistic budgeting approach.

The stark economic challenge presented first by the South's secession in 2011, taking with it two-thirds of former Sudan's oil production, and the subsequent oil export shutdown in January this year, was outlined by the IMF after its recent Article IV consultations with Khartoum. The IMF pulled no punches, arguing that the division of the country had 'translated for Sudan into the loss of a sizeable portion of its economic potential and a daunting challenge of adjusting to a permanent fiscal and external shock'. Following on from the contraction of exports and imports forced by the loss of oil revenue in 2011, H1 2012 saw revenue undershoot by 30 percent with no parallel reduction in government spending, boosting money supply which, in turn, carried inevitable inflationary impacts. The reduction in Sudan's GDP has been significant: the IMF projects an 11 percent contraction for 2012 and a smaller decline in 2013.

So the incentives for a political breakthrough were strong and the deal brokered in Ethiopia between Sudan and its southern neighbour has covered important ground. The September 27 agreement was significant in establishing a new security regime between the two countries, with a demilitarised border zone and an agreed tariff for South Sudan's exports via Sudan's pipelines and coastal terminals. The two sides also signed bilateral agreements on cross-border trade, banking, pensions and citizenship issues, and the deal allowed the newly appointed Sudanese ambassador to Juba to take up his post. But the two sides failed to agree on a compromise position over the disputed Abyei region and other disputed territory issues, which South Sudanese officials alarmingly have described as a 'ticking time bomb for the conflict resumption in the near future'.

Oil Deal Agreed

In the end, the oil segment of the deal was straightforward, once Sudan's maximalist demand for a $36/b tariff had been discarded and once Juba had agreed to a one-off treasury transfer of just over $3 billion to the North. The oil element of the agreement was struck in early August and left South Sudan paying an average $9.48/b for transportation, transit and processing fees for oil shipped through the Petrodar pipeline (80 percent of South Sudan's production from Blocks 3 and 7) and output from the Greater Nile Petroleum Operating Company (GNPOC) fields in Blocks 1, 2 and 4. As expected, the oil agreement took the form of a temporary deal for three and a half years, with the option to negotiate lower, but not higher, tariffs at its conclusion, giving Juba the opportunity to investigate alternative pipeline plans during the interim.

Such alternative routes to the twin pipes through Sudan, exporting Nile and Dar blends, include a proposal for a 2000 km pipeline to Lamu in Kenya which, it is estimated, would take at least three years to build. Another possible plan would see a new pipeline laid to Uganda, potentially linking up with Tullow Oil's discoveries there and transporting the oil further to the Kenyan coast. South Sudan is also pursuing plans, in line with its push for economic independence, to construct small topping plants to meet the country's 20,000 b/d requirement for petroleum products and ultimately allow some product exports to neighbouring countries.

Damage sustained in April to the Heglig oil field central processing facilities has been partially repaired, allowing northern oil production to reach the Khartoum refinery, but more work is needed before the surface facilities can handle full output from the fields. The Heglig facilities, operated by the China and Malaysia-owned GNPOC, are also the focus of a claim by Khartoum for compensation following the South's military occupation in April. Meanwhile, the Petrodar consortium operating the Block 3 and 7 fields expects to bring some 180,000 b/d of its 250,000 b/d capacity back on-stream in 4–5 months, provided that restart operations for the waxy crude run smoothly.

Ultimately, the degree of success that both countries can achieve in maintaining oil production will depend upon efforts to resolve the outstanding political issues regarding Abyei and the remaining disputed territories. Sudan's control in South Kordofan state, which adjoins the GNPOC-operated blocks, and Blue Nile state is challenged by opposition militants under the banner of the SPLM-N, representing non-Muslim communities that found themselves in Sudan following South Sudan's secession in 2011.

Differences Remain

It is not easy to project a straightforward resolution to this additional complication. Khartoum has rejected an offer from South Sudan to mediate between Sudan and the SPLM-N on the grounds that it did not recognise the latter 'politically, organizationally and militarily'. It also called on South Sudan to break off all ties with the rebel group. The SPLM-N, for its part, says its goal is to topple the Khartoum regime.

Meanwhile, disagreements over rules for a future referendum in Abyei and the apparent inability of Khartoum and Juba to agree an interim joint administration for the oil-rich area appear to kick hopes for a comprehensive final political agreement between the two sides further down the road. South Sudan recently rejected a call from Khartoum for the Abyei issue to be solved by political means rather than a referendum. Sudan's view is that the outcome of a referendum would make Abyei part of one of the two countries. This result would therefore be rejected by one of them, leaving open the possibility of a further conflict.

Economics and the countries' shared oil industry will bind them together, but it will be difficult to sustain economic cooperation until all political issues are resolved. For now, that prospect is distant. Both countries remain heavily reliant on oil revenue and the September agreement has provided a platform for joint efforts to attract fresh foreign investment. A new round of oil exploration awards in Sudan may help in the medium term. But continued border skirmishes and the lack of will on both sides to resolve all outstanding political differences mean that oil flows will remain vulnerable to disruption. ■

Commercial Developments in European Underground Gas Storage

AXEL M WIETFELD

Introduction/Opinion

I read with interest Issue No. 89 of the *Oxford Energy Forum* about 'Natural Gas Demand and Supply' published in August. The articles are topical and contain very useful information about inter alia European markets, price indexations, producers' market power and the global impact of shale gas. However, I believe, that none of the authors addresses the importance of underground gas storage for European gas supplies sufficiently.

Gas storage is the key to balancing this continuous gas import and seasonal/fluctuating demand of the markets and – more and more importantly – to realising the daily/weekly price spreads within the regional market and beyond.

Europe is facing a rising need for storage capacities as the gas demand will be growing and supplies come from increasingly remote locations. In addition, there are technical as well as economic and political risks in the transit countries, which are a concern for Western and Central Europe in winter times on a regular basis, underlining the essence of security of supply for the European economy.

Energy storage (gas, air, hydrogen) can also manage excess electricity supplies and thus help accommodate to renewable energies, which act as a game changer because they are extremely fluctuating and their share is growing.

1. Global Gas Demand

In Europe, gas demand of some 500 bcm in 2011 will increase further, albeit with uncertainties. To this end, current forecasts predict between 420 bcm and 620 bcm for European gas demand in 2030.

The IEA differentiates between various scenarios, in particular between a Current Policies Scenario with a steady reduction of the carbon footprint resulting in 620 bcm in 2030 and a New Policies Scenario in which carbon dioxide emissions will be heavily reduced resulting in 420 bcm in 2030.

All in all, the uncertainties regarding future gas demand in Europe relate mainly to the gas-to-power business. It is currently unclear to what extent Europe will continue to rely on coal and nuclear energy. It might well be that nuclear- and coal-fired power plants will be replaced by renewable energy and gas-fired power plants. That would definitely boost gas demand and accordingly increase the share of gas imports. In addition, demand forecasts are highly dependent on the availability of additional unconventional gas supplies at relatively low cost, however environmental concerns could easily delay or derail this development, in particular the production of shale gas. Public disquiet about shale gas in Europe puts a question mark over whether or not America's shale gas boom can be replicated elsewhere, e.g. in Western Europe. However, all in all, expanding unconventional gas production (both in Europe and worldwide) helps to restrain the rise in gas prices in Europe, which – together with additional policies encouraging gas use – drives up gas consumption, and hence increases the demand for underground gas storage.

2. Underground Gas Storage in Europe

The challenge for Europe is that there are less and less gas reserves, opening up opportunities for gas storage providers. It is not a coincidence that in a region which is short of gas reserves, plenty of storage facilities have been developed to structure the supplies. At present, we have an underground storage capacity in Europe of circa 94 bcm, plus Ukraine operates 32 bcm of underground storage capacity.

Europe is facing a growing need for storage capacities as supplies come from increasingly remote locations. The large-scale pipeline projects connecting Russia and the Caspian region with Central and Western Europe are clear evidence for that. By nature, it should be cheaper to add the flexibility component to those supplies close to the consumption centres rather than close to the production sites.

Moreover, there are technical and economic risks in the transit countries. Therefore, security of supply needs are to be guaranteed according to the n-1 principle, meaning that one faulty unit should not lead to an overload, fault or outage of another unit in the relevant network or supply chain.

Large storage operators help to bridge the growing distance to major supply regions and structure gas supplies. The competitive landscape of storage operators in Europe is quite diverse, however with familiar names. The likes of Eni, E.ON and GDF SUEZ have subsidiaries that provide storage services with a capacity of more than 10 bcm each (Table 1).

The top storage providers drive regional market integration, offer flexibility on demand to meet customer expectations and deliver operational solutions in accordance with the European storage guidelines set by the European Commission. They operate different types of storage facilities, i.e. porous rock/aquifer storage and cavern storage facilities.

Aquifer storage facilities or depleted gas fields are normally used for base load storage, e.g. for winter deliveries. They are mostly underground, permeable rock formations with reconditioned natural water reservoirs. For this storage type, up to additional 80 percent of working gas volume (WGV) is needed as cushion gas, which is sometimes lost to a certain extent when the facility is shut down. Most operational porous rock storage sites are depleted reservoirs.

The second type are cavern storage facilities. These are artificial, solution-mined caverns in gas-tight domal or bedded rock salt formations. General preconditions are: sufficient salt thickness, salt layer, salt pillow or salt dome, and sufficient leaching water with brine disposal opportunities. Salt cavern storage facilities are mainly used for peak-load purposes with high injection and withdrawal rates, which is what we call 'fast churn'. Salt cavern facilities need the smallest amount of cushion gas, i.e. approximately 1/3 of the WGV. Salt caverns are about 50 m in width and 200 m in height.

3. Value of Gas Storage in the Supply Chain

Companies make use of storage facilities basically for three reasons:

- Seasonal balancing
- Optimisation
- Security of supply

Seasonal balancing is the obvious and also traditional rationale for storing natural gas. Imports via pipeline or LNG supply contracts are in general characterised by base load structures to minimise costs. Therefore, additional storage capacities are required to provide seasonal balancing, i.e. to balance the difference between summer and winter consumption and thus making a margin out of the summer/winter spread.

A typical European consumption curve represents a high share of residential gas used for space heating and hence a high ratio between winter and summer demand. Consequently, gas is withdrawn from storage in high-consumption periods during the winter months, and injected into storage during periods of low demand in summer.

Low- and mid-churn storage facilities with moderate injection and withdrawal capacities are used to balance summer and winter consumption and provide more than 50 percent of the daily consumption on cold days in countries with a large residential consumer segment. Seasonal balancing is driven by the intrinsic value, i.e. the ability to capture the summer/winter spread through the 'total size'. The example of UK prices at the NBP (National Balancing Point) in 2008 and 2009 shows a summer/winter spread of 25p/therm which translates into 10€/MWh. Since storage fees are significantly lower, it was preferential for traders to store the summer gas.

It is fair to say that seasonal storage products meanwhile tend to play a less prominent role, but they significantly reduce supply costs due to their balancing effect.

Optimisation, the second rationale of the storage business, becomes increasingly important with higher liquidity in the energy markets. Traders basically optimise supply costs by monthly, weekly, daily and even intra-day balancing. The focus is on short to mid-term arbitrage deals and optimisation as well as cross-commodity spreads (gas to oil/power). Optimising with fast-churn storage is mainly driven by extrinsic value whereas the intrinsic value is of lower importance.

The extrinsic value describes the ability to capture daily price spreads through a 'fast-churn' capability. Within-week price fluctuations in the UK in October 2008 were more than 40p/therm which is the equivalent of approximately 16€/MWh. The result of the increasing extrinsic value of storage facilities is a price spread-driven utilisation of storage capacities for trading activities. This requires high injection and withdrawal peak rates in comparison to the WGV (fast churn).

An example of a fast-churn storage is E.ON's site in Holford, UK, which encompasses a WGV of only 160 mcm but a huge daily capability of 16–22 mcm. This shows that traders can generate in liquid markets (such as the UK) exceptional value out of price spreads and sometimes re-nominate and change between withdrawal and injection several times per day.

Prices at the CEGH (Central European Gas Hub) at Baumgarten in Austria can also be volatile, with traders trying to benefit from price fluctuations. In February 2012 CEGH prices jumped from 25€/MWh to 40€/MWh within one week which caused problems for traders without available volume flexibility and generated high profits for traders who had stored cheaper gas prior to that event.

We can conclude that storage – meanwhile – captures more value from daily price spreads than from the summer/

Table 1: Main storage operators in Europe (capacity in bcm)

Storage company	Regional focus	Current capacity	Future capacity
Stogit (Snam)	Italy	13.8	16.1
E.ON Gas Storage (E.ON)	Germany, Austria, UK, Hungary	12.8	15.3
Storengy (GDF SUEZ)	France, Germany	11.6	14.6
Wingas (Wintershall)	Germany, Austria	6.8	8.6
RWE	Germany, Czech Republic	5.1	5.8
NAM (Shell, Esso)	Netherlands	4.5	4.5
Enagas	Spain	3.6	5.7
Centrica	UK	3.3	6.5
Gazprom	Germany, UK, Austria	2.6	4.2
TIGF (Total)	France	2.6	3.7
OMV	Austria, Germany	2.3	4.0

winter spread, and that structuring via underground storage will become increasingly important. The focus obviously moves from temperature forecasts to gas price forecasts. Local underground storage in the European gas markets also helps managing temporary supply disruptions and LNG (Liquefied Natural Gas) transit times.

Overall, gas storage significantly contributes to security of supply, the third rationale for storing gas. The indigenous gas production of the European Union is expected to fall by over 40 percent by 2020, which will result in an import ratio >70 percent. Consequently, supply security has to be actively managed, as also requested by a decree of the EU. This can be best explained by looking back to an event three years ago. In January 2009, Europe faced the biggest ever gas crisis when all Russian supplies via Ukraine were disrupted, while temperatures fell below the 10-year average. The crisis completely changed the attitude of policy makers, customers and suppliers. Thus, the importance of deliverability came to light.

In December 2008, the first signal of an upcoming crisis was that expected import restrictions were officially announced. On New Year's Eve, less gas was delivered than confirmed, and unstable deliveries in the following days could be foreseen. However, it got even worse at the beginning of January 2009, when some Central European countries had to cope with no gas supply and a rapid fall of pipeline pressure. This resulted in the interruption of supplies to non-residential customers. Large European suppliers helped in this crisis with supplies from their underground storage facilities and deliveries from Western Europe. In return, Western Europe received additional LNG cargoes to meet the demand. In some countries, 90 percent of domestic demand was met by gas storage operators during the crisis.

4. Future Developments in Europe

There are good reasons for underground gas storage developments in Europe to continue. Existing storage capacities in 2011 amount to ~94 bcm. Countries with the largest amount of WGV are: ~20 bcm in Germany, ~17 bcm in Italy, ~13 bcm in France, 7 bcm in Austria and ~6 bcm in Hungary. Storage operators have reported ~16 bcm of additional WGV as being already under construction and ready for commission between 2011 and 2015. Further projects could be commissioned by 2020. These potential projects amount to ~22 to 35 bcm of additional WGV, meeting the European storage demand of ~130 bcm in a gas demand scenario of ~600 bcm. The higher amount of ~145 bcm of storage capacity would also help to meet a very high EU gas demand scenario (>650 bcm/a @ 75 % import dependency).

Storage operators are currently reluctant to take final investment decisions (FID) for additional storage projects due to uncertainties regarding future gas demand as described at the beginning. However, there seems to be a need for additional storage capacity.

Storage demand in 2020 is far ahead in the future, but developing the infrastructure takes time, i.e. approximately seven years for the development of a cavern storage project. If the specification for leaching the salt cavern started in late 2012, we could probably kick off a feasibility study in early 2013. We will need to do the basic engineering until 2015, followed by a final investment decision. Obtaining the mining, building and environmental permits takes about two years. If we are confident that the permits will be issued, we can simultaneously start the engineering work. Following these, we can proceed with the procurement and construction of sub-surface facilities, water and brine facilities, network and surface facilities. In the end, we would be able to finish the project in ~2019, i.e. seven years from now.

The remaining question is, how much such a project costs. Obviously, investment figures vary, but for one m^3 of WGV, we should calculate between 0.7 and 1.3 € in salt caverns and between 0.3 and 1.1 € in porous rock facilities (lower numbers reflect rather brown field projects/extensions, whereas higher numbers stand for more expensive green field projects/new investments). In absolute terms, this means that project developers would have to invest approximately €1.5bn for a 2 bcm storage site.

5. Underground Gas Storage as a Part of the Future Energy Supply System

The energy system will need more flexibility to accommodate to renewable energies, which act as a game changer because their share is increasing and they are extremely fluctuating.

Conventional power plants (such as coal and nuclear) mainly provide base load because they are – for economic and technical reasons – not capable of quick load changes. Peak supply can be provided by gas-fired power plants and pump storage water plants, but this form of flexibility is not sufficient compared to overall requirements. Consequently, we have to add flexibility with decentralised generation, smart grids and energy storage solutions, in which more and more gas companies are taking a leading role by developing new integrated energy supply solutions.

One example of a new integrated energy supply solution is the use of energy storage to cope with excess electricity supplies. We will face an oversupply of power from renewable energies in certain periods, but – as is well known – electricity cannot be stored effectively in large quantities. Consequently, 'surplus' electric energy has to be transformed into a different source, i.e. gas. This transformation is done by an electrolytic process, after which the gas (either pure hydrogen or, after additional methanation of hydrogen, methane) is injected into underground storage. Separate hydrogen caverns and technology have to be used. When renewable energies are not available, gas would be withdrawn from the storage site and supplied to a CCGT plant that produces electricity.

Gas storage is the only existing high-volume energy storage option that opens the door for power-to-gas and closes the 'gas-to-power, power-to-gas cycle'. Since gas has a higher energy density, it can be transported and stored quite efficiently. As the surplus electrical energy will be converted into gas, for which the transmission system is well developed, enormous electric transmission system developments can be avoided, considering the fact that renewable production is geographically far from the consumption centres. Another advantage is the underground location of the gas transmission system, while the high-voltage electric transmission grid is under the open sky and hence its licensing is increasingly complicated and expensive. ■

Asinus Muses

From Ian Skeet

The eighty-ninth was rather wonky,
There was no message from the donkey.
If retirement is his fate, Many thanks for eighty-eight

Don't worry, the donkey was just nodding for a while.

Transparency tantrums

Asinus has previously noted the kicking and screaming of energy companies in response to the threat of transparency laws in the US. Industry groups had argued for a variety of loopholes, including exceptions for countries that just don't like the idea, such as China, Angola and Qatar. Regulators have sat through the tantrums and stuck to their principles: more than a year later than it was mandated by the US Congress, the Securities and Exchange Commission has passed a rule requiring natural resource companies to disclose all payments above $100,000 to governments. Lobbying for the industry, the American Petroleum Institute claimed that disclosing payments was like 'giving the formula for Coca-Cola.' Apparently it's not their technology, knowledge or managerial excellence that gives US companies their competitive edge, their secret sauce, their 11 herbs and spices, but, rather, their eye for the apposite bribe. With lobbyists like this, who needs green groups to besmirch the oil industry?

Scholarly purity

It is not only dictators and corrupt officials who might oppose Big Hydrocarbon transparency. It seems that certain humble denizens of academia have been accepting industry money to extol the virtues, and minimise the risks, of natural gas fracking in the US. The lead author of one supposedly-independent report is a professor at a department at the University of Wyoming that received $6 million in donations from the oil and gas industry last year. Another professor, who authored a study that found no evidence of groundwater contamination from fracking, is a member of the board of a major Texas fracking company, a post for which he received $400,000 in 2011, more than double his university salary.

Here at the Oxford Institute, of course, we maintain rigorous impartiality, guaranteed by two methods. First, our paying subscribers belong to a range of competing interests including companies and governments of both producer and consumer countries. That our sponsors are unlikely to agree on any given issue should leave us free to take an independent view. The second method calls to mind the policy of the Singaporean government, which pays politicians so much money that they would never feel the need to take bribes. The President's personal salary, for instance, is over $4 million. Our Oxford version is virtually identical, though simply flipped over: we pay so little that no one driven by a desire to make money would ever be tempted to apply for a job.

Renewables and re-useables

Europe's renewables industry has received a modest kicking from a study produced by two experts at Friedrich Schiller University in Jena. In 8 out of 10 tests they found that rapeseed biodiesel failed to produce the greenhouse gas savings of 35% required of biofuels for transport, compared with fossil fuels.

The biggest downside of the biofuel industry is that it takes edible commodities out of the food chain, pushing up food prices. But a small bus company in Asinus's hometown, named The Big Lemon, knows how to have its cake and eat it: first use rapeseed oil to make chips, and only then turn it into biodiesel. The company supplies food-grade oil to local restaurants and hotels and then collects it after use, processing it into fuel for their buses. They claim an environmentally friendly supply chain in which the factory that turns the oil into biodiesel uses no water except for that used to make tea by the employees. Asinus suggests that with the right sanitation equipment they could even recycle that, but admits it may be pushing environmentalism beyond the limits of good taste.

Supermarket sweep

It is not only bus companies that can ally food and alternative energy. Who is Europe's biggest solar power generator? Not the ironically-tagged Beyond Petroleum; not E.ON, the flagship power company of Europe's politically greenest country, Germany; not even, apparently, an energy company at all. Revealed: British grocers Sainsbury's, having installed more than 69,500 solar panels on its stores, covering an area the size of 24 football pitches and generating 16MW, takes the title.

A mislaid ass

Good renewables news also that US wind power production recently passed 50GW of installed capacity.

Always ready for a new challenge, Asinus's favourite Texan, T Boone Pickens, is back in the wind business. No stranger to overcoming setbacks, Pickens was forced to scale back plans for a 1000MW wind farm to a more modest 377MW, announcing on MSNBC that 'I've lost my ass in the business.' Asinus can only hope the poor beast finds its way home.

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