Executive Summary

- The on-going privatisation of the power sector in Middle Africa’s largest economy and Africa’s most populous country, Nigeria, represents a critical juncture in attempts to plug a major infrastructure bottleneck; for its population of 160 million, Nigeria generates just over 4,000 megawatts (MW) of electricity, 3 times less than New York City, which generates 13,000 MW for its 10 million residents.

- The challenge extends beyond Nigeria. Africa is home to 15% of the world’s population, but it consumes just 3% of the world’s energy output, and generates less than 50% of the 74,000 MW of current peak demand requirement. Moreover, electrification rates are low with only 25% of the region’s population having access to power. The average for developing countries is 72%.

- At least 30 countries in Middle Africa experience daily outages, which is estimated to cost anywhere between 2%-5% of GDP in some of the worst affected economies. At the level of business, this translates to outage costs of up to $1.25 per kilowatt hour (kWh) of interrupted electricity for the average firm, which is equivalent to $3,650 per kW, and represents economic losses of up to 80 hours every month.

- While generating capacity has remained largely stagnant over the past 5 years in the region, the demand for electricity is likely to grow at an average annual rate of 3% over the next 20 years. Over the next 15 years, Africa needs to add an extra 300 gigawatts (GW) (or 300,000 MW) of capacity to meet that demand growth. This would require any new capacity to double to around 7GW a year in the very near-term and perhaps quadruple by 2030.

- More than 50% of the power generation capacity of Middle Africa is based on fossil fuels - diesel specifically. This equates to average generating costs of around USD$400/ megawatt hours (MWh), which has proved in some cases, to be more expensive than certain renewable energy technologies.

- Given the obvious investment opportunity in the sector, a challenge for investors seeking power assets in Middle Africa will be to find ways to unlock financial value across the value-chain of power generation, transmission and distribution infrastructure, for both assets being sold and for new projects.

- Globally, investment costs per Megawatt (MW) for generation assets have averaged US$1.1 million across key emerging markets and developed economies, but assets in Africa, privatised and newly built, have sold for almost 50% less and 20% less, respectively, than the global average in some cases, underpinning considerable upside on returns with the right capital outlay.

- The move towards unbundling and privatisation in Middle Africa has been beneficial in so far as it has helped to separate the monopolies in transmission and distribution (T&D) from the generation component of the value-chain. While these reforms have led to the emergence of sole state-utility purchasers of electricity from independent producers (IPPs), the emerging tide of private sector interest is likely to see a greater push towards models that allow other large customers, and not just state utilities, to purchase power directly from IPPs.

- Meanwhile, T&D losses in sub-Saharan Africa (SSA) continue to occur between sources of supply and points of distribution, and the cost of these inefficiencies is approximately $5bn annually. Utilities across the region actually lose up to 25% of power consumed as a result of these inefficiencies, compared to a 10% global average.

- In West Africa alone, the likely T&D infrastructure upgrade requirement will be $500mn in 2014. Thus far, much of the external funding for T&D has been directed at integrated transmission and distribution networks, perhaps underscoring investors’ perception that economic gains are more likely, and efficiency losses less likely, when both transmission and distribution are integrated.

- The financial viability of these power projects is being aided by tariff reforms, government funding support to utilities, and the involvement of development finance institutions (DFIs) and export credit agencies (ECAs) in projects. However, the long-term capital commitments, and commercial and political risks mean only a few investors are prepared for the long-haul.

- Although still a smaller part of the energy mix in most countries, renewable energy accounts for almost 20% of total installed electricity capacity in Africa. However, in the near-term, the full penetration of renewable energy into the African market will largely hinge on investment security.
Introduction: Powering a low base

On 1 November, Nigeria’s government handed over privatised power assets to new owners in the first phase of a process aimed at plugging one of the region’s most critical infrastructure gaps. The next phase will see 10 National Integrated Power Projects (NIPPs) completed and sold to private operators by the end of March 2014. Nigeria’s generation of around 4,000 megawatts (MW) falls far short of the almost 13,000 MW required to meet peak demand. Indeed, New York City, with a population of just fewer than 10 million, has a generation capacity of 13,000 MW, three times larger than Nigeria as a whole with its 160 million-strong population. However electrification and generation challenges are hardly unique to Nigeria.

Africa may be home to 15% of the world’s population, but it consumes just 3% of the world’s energy output, and generates less than 50% of the 74,000 MW of current peak demand requirement. In sub-Saharan Africa (SSA) electrification rates are low with only 25% of the region’s population having access to power; the average for developing countries is 72%. To plug this gap, at least $300 billion in investment will be required over the next two decades.

Electrification rates in Sub-Saharan Africa (%)

The large gap in power infrastructure and the component parts of the electrification value chain would suggest that the sector provides a ready play for investors seeking new and rewarding growth opportunities. Indeed the annual funding requirement for the region’s power sector between now and 2015 is estimated to be at least US$40.6 billion, with an annual funding gap of around $20bn. There is also a clear gap in generating capacity. In 2011 for instance, Nigeria, the second largest net generator of power in sub-Saharan Africa, generated just 25 billion kilowatt hours, compared to South Africa, the largest generator, which in the same year generated 242 billion kilowatt hours.

While an estimated 80% of current funding sources for the power sector comes from public sources, primarily through taxes and tariffs, a spectrum of financial investors are looking to pitch tent in this fast-growing market. However, the average investment commitment in a single power project in the region is approximately $300mn. In this report we examine the growth potential for the power sector in Middle Africa, how the market can place financial value on power assets, particularly recently privatised generation and distribution assets in markets like Nigeria, prospects for the transmission and distribution segments of the value-chain, the main challenges facing investors, the shifting regulatory landscape of the region’s power markets, financing prospects and opportunities and the outlook for renewable energy.

Total Electricity Net Generation (Billion Kilowatt hours) in SSA vs. South Africa’s net generation, 2008 – 11 (Billion Kilowatt hours)
Power demand, costs accelerate as fuel economics take on more significance

The demand for electricity in Africa is likely to grow at an average annual rate of 3% over the next 20 years, though generating capacity has remained largely stagnant over the past 5 years. SSA has average power consumption per capita of 120 kilowatt hours (kWh) per person per year, representing a sixth of the global average. At its current 4% growth rate however, per capital energy consumption in Africa is growing faster than anywhere else in the world. This trend has been driven by even just limited improvements in infrastructure in many countries and overall rising levels of foreign direct investment (FDI) which have boosted economic growth. Large economies such as Nigeria have still posted average growth rates in recent years of between 6%-7% despite the severe outages and inefficiencies in the power sector. Over the next 15 years, the continent needs to add an extra 300 gigawatts (GW) (or 300,000 MW) of capacity to meet demand growth, which would require any new capacity to double to around 7GW a year in the very near-term and perhaps quadruple by 2030.

At least 30 countries in Africa experience daily outages, which cost anywhere between 5% of GDP in countries like Uganda and Malawi and between 2%-5% in Tanzania and Kenya. At the level of enterprise the economic costs are even more startling. In SSA, the average firm incurs outage costs of up to $1.25 per kWh of interrupted electricity, which is equivalent to $3,650 per kW, and could also represent economic losses of up to 80 hours every month. Even if standard subsidised tariffs are replaced by cost-reflective tariffs, many businesses could still benefit and improve productivity if net outage costs are used for other purposes such as hiring new workers or purchasing new equipment.

Average Electricity Costs, 2012 (US cents/kWh)

<table>
<thead>
<tr>
<th>Country</th>
<th>Capital Costs</th>
<th>Operating Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Burkina Faso</td>
<td>7</td>
<td>17</td>
</tr>
<tr>
<td>Ghana</td>
<td>6</td>
<td>8</td>
</tr>
<tr>
<td>Kenya</td>
<td>5</td>
<td>8</td>
</tr>
<tr>
<td>Tanzania</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>South Africa</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>Zambia</td>
<td>4</td>
<td>4</td>
</tr>
</tbody>
</table>

Sources: Ecobank Research, EIA.

Outside of North Africa, the cost of energy services is much higher in Africa than in other parts of the developing world, where costs range from US$0.05-US$0.10 per kWh. The large dependence on petroleum products and frequent recourse to high cost, emergency power generation are key cost drivers. For instance, firms and multinationals in natural resources and manufacturing have focused their early stage capital investments on captive power generation due to the lack of reliable electricity from many national grids. Meanwhile, a number of studies have documented the higher landed costs of petroleum products i.e. before tax, in African countries when compared with global prices for the same products. Landed shipping costs of diesel at ports in Africa are typically 10%-15% higher than in Europe. In addition, the transportation of petroleum products from African coastal ports to landlocked African countries also adds to the cost burden. The region’s primary fuel source is diesel. More than 50% of the power generation capacity of Mauritania, Equatorial Guinea and the DRC, and more than 17% in the West Africa region is based on diesel fuel. This could equate to generating costs of around US$400/MWh, which in some cases is actually more expensive than most renewable energy technologies.

African power generation by fuel % (2012)

However, several new power plant construction technologies being employed are starting to provide scope for expansion and upgrades that could lead to future cost savings. For instance, eight of Nigeria’s National Integrated Power Projects (NIPP) were initially designed as open –cycle gas turbine (OGGT) power plants and the remaining two are designed as combined-
cycle gas turbine (CCGT) power plants. Seven of the OGTT plants have the capacity to be expanded to combined gas turbine (CCGT) configuration, highlighting their potential to benefit from the likely decreasing cost trajectory of CCGT technology.

**Fuel source as % share of the total energy mix in selected SSA countries (2012)**

Sources: IEA, World Bank

Gas-fired plants however remain sensitive to fuel cost fluctuation, representing anywhere between 55% and 71% of total levelised costs of CCGTs, depending on the discount rate applied. The generation costs of gas-fired plants are also highly sensitive to variations in fuel costs, above all other parameters, and to a greater extent than other fossil-fuelled plants; variable costs are the main determinant of the cost for fossil-fired plants. With an increased cost of capital the total generation cost for all types of general technologies increases. However, current plans by the Nigerian government for a domestic gas pricing framework should help assure a degree of price stability for its domestic gas supplies. An additional advantage and observation of the predominant technology in Nigeria – gas – is the relative stability of the cost of gas-fired power and hence its relative insensitivity to discount rate changes, compared to other generation technologies.

**Levelised generation cost* ranges for generating technologies, (US$/MWh)**

<table>
<thead>
<tr>
<th>Type of generation</th>
<th>At 10% discount</th>
<th>At 5% discount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal-fired</td>
<td>35-60</td>
<td>25-50</td>
</tr>
<tr>
<td>Gas-fired</td>
<td>40-63</td>
<td>37-60</td>
</tr>
<tr>
<td>Nuclear</td>
<td>30-50</td>
<td>21-31</td>
</tr>
<tr>
<td>Wind</td>
<td>45-140</td>
<td>35-95</td>
</tr>
<tr>
<td>Solar</td>
<td>200+</td>
<td>150</td>
</tr>
<tr>
<td>Micro-hydro</td>
<td>65-100</td>
<td>40-80</td>
</tr>
</tbody>
</table>

* Levelised cost is the price at which electricity must be generated from a specific source to break even over the lifetime of the project.

**Generation asset valuations reveal strong upside**

Companies with power assets in many emerging markets are in a market with strong cash flows and growth curves, making them a darling of emerging market equity markets. Investors in the African market in general will acquire assets that offer real value compared with their price. Others may be hoping to capitalise on demand forecasts for specific types of fuel, while, yet others will see generation assets as a way of hedging a key source of supply for their existing businesses. Ultimately, however, the challenge for investors will be to find ways to unlock financial value across the value-chain of power, generation and distribution infrastructure. The main driver, has, of course been economic growth which in turn has fuelled electricity demand.

Nigeria’s power sector was privatised in 2013, following the sale of power generation and distribution assets to private investors. The first seven Gencos, which have an installed generation capacity of 5,440MW were sold for a total sum of US$1.78 billion, and represent a valuation of $550,000/MW. Given the revenue potential these assets probably represent a good investment, underpinned by the prospective future cash flows of the plants. Based on our estimates, these assets could potentially generate about $1.2 billion in revenue from full year operations assuming at least 90% gas availability for the gas-fired plants and a 75% load factor all round. Nigeria’s 10 IPP plants being offered under the second phase of the power asset privatization – the National Integrated Power Projects (NIPP) – could also yield estimated revenues of $1.1 billion. Compared to acquisition costs, this represents an estimated annual income of $229,190/MW, which could increase in 2014 when tariffs are revised upward.

Globally however, costs per MW for generation assets have averaged US$1.1 million across key emerging markets and developed economies. If we apply this global average multiple to the NIPP companies that have been completed or are under construction in Nigeria, costs per MW rose considerably compared to the legacy generation assets sold under the first phase of Nigeria’s power sector privatisation. The largest of the NIPP assets Alaoji IPP has a capacity of 1074 MW is valued at approximately US$1.2bn or US$1.1mn/MW for an 80% share of the plant. Its closest peer among the privatised legacy assets
is the 1030MW Egbin thermal power generation plant, 70% of which was sold for US$407mn, and thus valued at US$395,000/MW

Global Power Generation Company Comparatives (Data gathered in Q4 2013)

<table>
<thead>
<tr>
<th>Power Generation Company</th>
<th>Country</th>
<th>Plant Type</th>
<th>Capacity MW</th>
<th>Enterprise value (EV - Est based on 2012 y/e) USDm</th>
<th>Estimated** Total Cost USDm</th>
<th>Average Power Tariffs Industrial USDc/KwH</th>
<th>Average Power Tariffs Residential USDc/KwH</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tractebel Energia SA</td>
<td>Brazil</td>
<td>Hydro, thermal</td>
<td>1030</td>
<td>1133</td>
<td>14.2</td>
<td>9.6</td>
<td></td>
</tr>
<tr>
<td>Beijing Jingneng Clean ENE-H</td>
<td>China</td>
<td>Thermal</td>
<td>3,657</td>
<td>3,961</td>
<td>4353</td>
<td>12</td>
<td></td>
</tr>
<tr>
<td>Nava Bharat Ventures Ltd</td>
<td>India</td>
<td>Thermal</td>
<td>451</td>
<td>367</td>
<td>496</td>
<td>11.3</td>
<td></td>
</tr>
<tr>
<td>Torrent Power Ltd</td>
<td>India</td>
<td>Thermal</td>
<td>1648</td>
<td>2,411</td>
<td>1812</td>
<td>11.3</td>
<td></td>
</tr>
<tr>
<td>Egbin Power***</td>
<td>Nigeria</td>
<td>Thermal</td>
<td>1030</td>
<td>1,096</td>
<td>1133</td>
<td>12</td>
<td>9.6</td>
</tr>
<tr>
<td>Drax Group</td>
<td>UK</td>
<td>Coal</td>
<td>5960</td>
<td>2,857</td>
<td>4356</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>First Energy Corp</td>
<td>US</td>
<td>Thermal, Hydro</td>
<td>18,000</td>
<td>35,609</td>
<td>19600</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>Eskom (holding SOC Ltd)</td>
<td>South Africa</td>
<td>Thermal</td>
<td>721</td>
<td>-</td>
<td>793</td>
<td>9</td>
<td></td>
</tr>
<tr>
<td>Kengen</td>
<td>Kenya</td>
<td>Thermal</td>
<td>1295</td>
<td>1,255</td>
<td>1424</td>
<td>15</td>
<td>19</td>
</tr>
</tbody>
</table>

Sources: ***Ecobank Research, Bloomberg, Company websites

To put these values in context, Ecobank Research analysed listed power generation companies (see table above) across some emerging markets and advanced economies. Power generation assets have historically traded at relatively high multiples. A peer group of companies in China, India, South Africa, Kenya, the UK and US, as at December 2013, were trading at an average EBITDA multiple of 8.46x. Kengen of Kenya is the most similar in capacity and EBIDTA to Egbin, and was trading at 7.94x EBITDA in Q4 2013. Estimates for Egbin’s EBIDTA in 2014 are near $130mn under a best-case scenario, considering the total value of Egbin was US$581mn, there appears to be ample scope for further capital expenditure in line with the peer group companies while creating and generating value for its new owners. Across the board, the upside for generation assets in a cost-reflective tariff environment is strong. One of the peer group companies analysed by Ecobank Research, Tractebel Energia SA of Brazil, is a case in point. In 1998 Tractebel acquired 68% of the Brazilian state owned electricity generation company Gerasul for US$0.8 billion. At the time Gerasul had installed generation capacity of 3,700 MW. Tractebel traded then at 1.95 BRL (US$1.69 at the time) on the stock market. Tractebel almost doubled its initial 3,700 MW installed capacity to 6,909 MW in 2013. Brazil, like Nigeria, has a fast growing population (190 million), fast developing economy, and growing energy consumption. Tractebel supplies approximately 6.3% of the country’s installed capacity. In addition since 1998, Tractebel’s installed capacity has increased by 86% while the share price has increased by 1,884% to 38.7 BRL (US$17.04), and has out-performed Brazil’s stock market index since 1998 (see chart below).

SSA cost factor for residential tariffs, compared to other regions*

Weak cost recovery (see chart above) has reduced the ability of state utilities to maintain plants and equipment, leaving little capital to expand or rehabilitate infrastructures, and opening up avenues for cheaply priced assets to be snapped up by an emerging private sector in many SSA markets. Through an aggressive growth and plant expansion strategy, backed by reforms aimed at improving cost recovery for generation companies, Tractebel almost doubled its initial 3,700 MW installed capacity to 6,909 MW in 2013. Brazil, like Nigeria, has a fast growing population (190 million), fast developing economy, and growing energy consumption. Tractebel supplies approximately 6.3% of the country’s installed capacity. In addition since 1998, Tractebel’s installed capacity has increased by 86% while the share price has increased by 1,884% to 38.7 BRL (US$17.04), and has out-performed Brazil’s stock market index since 1998 (see chart below).
With the expected increase in demand for power from residential, commercial and industrial users expected to remain buoyant in 2014, both financial and strategic investors are likely to view the generation end of the power-value chain as a sure-fire returns investment in markets that are coming from a low base.

Sources: Bloomberg, Ecobank Research

Unlocking value in transmission and distribution (T&D) assets as unbundling accelerates

Power transmission and distribution (T&D) losses in sub-Saharan Africa (SSA) often occur between sources of sources supply and points of distribution, and the cost of this inefficiency is approximately $5bn annually. Power utilities across the region actually lose on average up to 25% of power consumed as a result of these inefficiencies (see chart below), compared to a 10% global average. The cost to African economies is significant. Some utilities such as South Africa’s ESKOM have managed to reduce T&D losses by as much as 10% in the past 18 months, while West Africa’s move towards an energy efficiency policy seeks to reduce T&D losses across the region from up to 40% currently, to 10% by 2020. In East Africa, significant improvements were also made in the period between 2005 and 2011. In Kenya for instance, line losses fell from 18% in 2005 to 16% in 2011, while collection rates increase to 99% in 2011 from 85% in 2005. Efficiency gains were also strong in Uganda where distribution losses fell by 10% to 27% between 2005 and 2011.

The infrastructure requirements for T&D reforms in West Africa alone are estimated at $500mn over the next decade. A key focus is likely to be projects aimed at upgrading existing transmission lines and distribution systems, while a key source of funding for T&D infrastructure projects are multilateral and foreign institutions. A recent example is the European Investment Bank’s (EIB) plan to fund the construction and upgrade of 100km transmission lines and 200km of distribution infrastructure in Zambian capital, Lusaka for a consideration of US$107mn out of a total project funding requirement of $258mn. Much of the external funding for this part of the power infrastructure value chain has been directed at integrated transmission and distribution network, perhaps underscoring investors’ perception that economic gains are more likely and efficiency losses are less likely when both transmission and distribution are integrated.

SSA distribution line losses of power utilities (losses as a % of power supplied) in 2011

In terms of policy the most basic models have seen government attempts to improve metering and billing systems, conduct regular line inspections to tackle illegal connections, improve maintenance, create high voltage distribution systems, and embark on corrections to reduce losses. However a more fundamental question is whether the region’s current T&D model is optimal, and how financial investors might benefit and realise returns on projects aimed at reducing T&D losses?

The move towards unbundling and privatisation in Middle Africa has been beneficial in so far as it has helped to separate the monopolies in T&D from the generation component of the value-chain. However, this model has only made economic sense where the generation segment has proved to be competitive, and has operated efficiently. This has been a major challenge
for Middle Africa, and thus a natural response has seen the emergence of hybrid models in some countries, where state utilities act as the sole purchasers of electricity from IPPs. However, the currently evolving cycle of private sector interest is likely to see a greater push towards models that allow other large customers and not just state utilities to purchase directly from IPPs.

Regional power pools remain fragmented despite potential cost savings

Africa’s current transmission system has a total length of 89,000km. Compared to the area of the continent, it is small, and corresponds to a density of 3.29 meters of transmission line per square km. Thus, the capacity of the system for regional exchanges is extremely limited and is inadequate to provide for the long distance transmission services needed to spur development of regional generation capacity. As such, the opportunities for businesses to capitalise on cross-border power pools, despite their existence, have been hindered by the relatively fragmented regional and continent-wide power trade market. Average historical costs of different SSA power networks show wide variations. For instance, a handful of networks are based on low cost, locally sourced energy such as South Africa on coal and Zambia depending on its hydro resources. However, a much larger number of SSA networks have significantly higher total costs, in particular operating costs, reflecting their dependence on higher cost imported fossil fuels for thermal power generation.

In reality, the cross-border power trade has yet to take off outside of the Southern Africa Power Pool (SAPP). In SAPP about 10% of total consumption came from trade activities in 2008, but this share dropped significantly thereafter due to generalized capacity shortages.

SSA Regional Power Pools Consumption and Trade (Terawatt hour, TWh)

<table>
<thead>
<tr>
<th>Region</th>
<th>Consumption (TWh)</th>
<th>Imports (TWh)</th>
<th>Exports (TWh)</th>
<th>% of electricity traded</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Africa Power Pool</td>
<td>8.8</td>
<td>0.01</td>
<td>1.8</td>
<td>0.1</td>
</tr>
<tr>
<td>East Africa Power Pool</td>
<td>13.41</td>
<td>0.28</td>
<td>0.18</td>
<td>2.1</td>
</tr>
<tr>
<td>West Africa Power Pool</td>
<td>28.63</td>
<td>1.63</td>
<td>2.04</td>
<td>5.7</td>
</tr>
</tbody>
</table>

Sources: Bloomberg, Ecobank Research  *TWh is used for measuring larger amounts of electricity, especially to express annual electricity generation for entire countries.

However, even in the SAPP most of the trade such as between South Africa-Mozambique, Zambia-Namibia – is governed primarily by bilateral contracts. In West Africa, the statistics are worse; the power trade accounts for only 5% of the sub-region’s total consumption. A key impediment, which clearly represents an investing opportunity, is the poor state of Africa’s existing transmission network. This undermines the near-term prospect of an efficient regional electricity trading network. The main challenge is that higher regional power integration would require significantly more capital investment, and would need to incorporate large hydro plants which produce at much lower costs than thermal plants which are capital intensive. Ultimately however, regional integration is likely to allow greater cost savings, since they largely depend on hydro rather than thermal sources. These regional systems are clearly long-term undertakings, but could save the continent up to US$43bn a year between now and 2040, or more than 20% of the current cost electricity.

Several multilateral financial institutions are helping to underpin financing for these types of cross-border projects. The African Development Bank (AfDB) in December 2013 boosted the Cote d’Ivoire – Liberia – Sierra Leone – Guinea (CLSG) electricity network interconnection project with financing support of $195 million. The project involves the construction of 1400 kilometres of high voltage (225kv) lines, building of 11 sub stations and two regional control stations. The project, will, in the first phase allow Liberia, Sierra Leone and Guinea to import power from Cote d’Ivoire, while subsequent phases are expected to enable sharing of power between all four countries. The project will increase electrification rates in the four countries to an average 33% and improve rural access to the electricity in over 125 locations along the transmission grid pathway. More importantly, the project is expected to reduce the cost of electricity in the importing countries. These types of projects would lend credence to a widely held view that the cross-border trade in power can reduce the overall costs of electricity supplies. By importing electricity at prices that fall below the domestic cost of production, the cost per kWh of electricity can be reduced by up to 20% in many Middle African markets, given fact that sources of energy such as hydro or gas are unevenly distributed within the region.

Growing gas resources will attract integrated utilities looking to secure feedstock for generation

Domestically, the power sector will be the most crucial off-taker of gas in Middle Africa. Gas contributes around 25% of total power generation in Sub-Saharan Africa, is only second to coal and will also account for an increasing proportion of the region’s fuel mix. With Middle Africa needing to spend an estimated $23 billion annually over the next decade to meet its
power needs, government will need to introduce policies that are conducive to supporting gas supplies to the domestic market. Gas-fired power projects in the region are likely to consume over 5 billion cubic metres of gas every year, in order to generate at least 2,892MW of electricity. However, this is still well below the region’s electricity requirement of around 74,000 MW.

Nevertheless the expected rise in gas consumption for these projects means that Africa’s gas reserves and potential production will play a crucial role in plugging any near-term production gaps for gas supplied downstream to the power sector. Indeed, beyond the requirement for healthy power sector demand to sustain gas production and development, at the early stages of potential LNG development, gas demand from the power sector is often seen as crucial indicator for a viable project. East Africa is now one of Africa’s most gas-rich regions, boasting at least 100 trillion cubic feet (tcf) of reserves. Other sources of gas for power sector consumption are also emerging: Lake Kivu on the border of the DRC and Rwanda for instance has methane (dry gas) resources at a depth of around 500 metres that could support an installed capacity of gas turbines of 1000 MW generating power over the next five decades. However, gas production in the region would still need to grow by 50 times to fill Africa’s electricity gap, assuming only gas projects were used to fill this gap.

There is a huge requirement for power in East Africa, which could easily be met by gas resources. However in many East African countries hydro-power is prevalent, and these plants although costly at the onset to develop and build have a low operating cost as they do not require fuel purchasing. Consequently, governments have been able to maintain relatively low tariffs for hydro-fuelled electricity, levels which are likely to be unsustainable for gas fuelled electricity, at least in the short-term, and may thus deter substantial investment. Nevertheless there is a growing recognition amongst policy makers of the need to create a competitive environment; after a prolonged low-price run gas prices for power generation in Tanzania, have, for example, been revised upwards to around $5/MMBTU, from as low as $2/MMBTU. However, with the exception of the Middle East where gas prices are lower, Africa still has lower wholesale gas prices that other world regions (see chart below).

% Share of Power Generation in Sub-Saharan Africa by Fuel Type

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear Energy</td>
<td>2%</td>
</tr>
<tr>
<td>Liquid fuels</td>
<td>17%</td>
</tr>
<tr>
<td>Hydro &amp; Renewables</td>
<td>25%</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>46%</td>
</tr>
<tr>
<td>Coal</td>
<td>2%</td>
</tr>
</tbody>
</table>

Sources: Bloomberg, Ecobank Research, IGU

Nevertheless, the expanding gas reserves in Middle Africa will prove increasingly attractive for investors and firms seeking an integration strategy that secures gas supplies and feedstock for those firms’ thermal power plant projects at competitive prices. The proximity of projects to local sources of feedstock is critical. Ghana’s relatively new 132MW Takoradi II plant is able to operate using light crude oil, natural gas, diesel, sourced domestically or regionally through the West Africa Gas Pipeline (WAGP), though challenges in Nigeria have disrupted gas supplies to Ghana in recent months.

Sector regulation remains a key consideration for both corporate and financial investors

Investments in Middle Africa’s power sector are hardly for the marginal player; the capital requirements are massive and the project tenors are long, with typical project lead times of more than 5 years in some cases. Local bank financing capacity in USD is also constrained particularly for large projects which local currency funding is unable to adequately cater for. Given the challenges of local funding, foreign financiers feature prominently on the spectrum of funding sources for power projects. Governments are also responding to the risk concerns of these investors and have in the past few years embarked on a host of regulatory and sector reforms aimed at underwriting and in some cases ‘de-risking’ power projects on the continent. The biggest sign of this has been the steady rise of IPPs, the restructuring of tariff frameworks, the outsourcing of utilities management, and implementation of pre-paid meters.

To date however, the biggest challenge in most countries of the region has been the subsidised tariff structures for electricity. Governments have historically priced tariffs based on what low income economic groups can afford, a situation that has undermined to a large the commercial viability of large power projects to a large extent. Cost reflective tariffs based on current...
and forecast generation technologies would ultimately attract IPPs and allow them greater scope to access funding. In many countries across the region, the existing power infrastructure is fully depreciated, and thus the increased costs of new power generation and those generated from different sources need to be taken into account. While there is now a general trend towards liberalisation, the review of tariff structures, privatisation and the unbundling of power utilities, power utilities have suffered under financial stress, both from a result of revenue-under-collection and weak cash flows. These have regularly undermined their ability to provide good partnerships with private investors.

To a large extent, the role played by government especially in supporting the buyers of electricity is extremely critical. Private sector lenders, equity investors and project developers all seek investment security, particularly where Power Purchase Agreements (PPA) are concerned. Payments need to be made in time, and termination agreements need to be equitable. In the South African example for instance, a highly leveraged utility and electricity buyer such as Eskom requires support with PPAs from the government, in order to make these projects bankable for independent producers. In the 20th century almost all major power projects in Middle Africa were financed publicly, through concessionary loans aid, and Development Finance Institutions (DFIs). Perhaps this made sense then, given that the funding sources underpinned a system of generation assets that were largely state-owned, and vertically integrated. Now with the advent of Independent Power Projects (IPPs) and new power plant construction, funding sources options and opportunities are diversifying.

In 2013, the World Bank approved its first ever guarantee to a Chinese firm to borrow money for a power project in Middle Africa. The multilateral lender, through its Multilateral Investment Guarantee Agency (MIGA) is expected to provide China’s Triumph Power a political risk guarantee against failure to enable the firm to access $102.5 million to build a planned 83MW heavy fuel oil power plant in Kenya. The guarantee was provided as part of the World Bank’s Least Cost Power Development Plan, which is seeking to diversify the country’s energy sources and also increase the private sector participation in the power sector through IPPs. Other IPPs expected to receive similar guarantees include Thika Power, OrPower4 and Gulf Power, who alongside Triumph Power, are expected to add another 600MW to Kenya’s power supply. The guarantee for the Chinese company was first of its kind in Africa, and could be replicated elsewhere on the continent.

World Bank’s Least Cost Power Development Plan for Kenya

<table>
<thead>
<tr>
<th>Project Description</th>
<th>Capacity (MW)</th>
<th>Time Lines</th>
<th>Implementing Agencies</th>
<th>Costs US$Billion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Committed Generation Projects</td>
<td>1815</td>
<td>2011-2015</td>
<td>Kengen &amp; IPP</td>
<td>3.9</td>
</tr>
<tr>
<td>Proposed Generation Project</td>
<td>18,920</td>
<td>2015-2021</td>
<td>Kengen &amp; IPP</td>
<td>41.4</td>
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<tr>
<td>Proposed Transmission Projects</td>
<td>10,545</td>
<td>2011-2021</td>
<td>Ketraco</td>
<td>4.48</td>
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<tr>
<td>Total Cost</td>
<td>554.7 Billion</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Sources: Ecobank Research, World Bank

From commissioning stage to development and completion, power projects are very complex, and remain a challenge to get to bankability and then to financial close. The complexity of such projects is multiplied several times where regional projects are involved, and IPP developers have to spend millions in risk capital even just in the early phases of project development. Thus for the cash-rich lenders, a clear path towards financial closure becomes a critical requirement of any project.

Average tariffs* (US cents/kWh) for household monthly consumption of between 50-450kWh for selected SSA economies in 2011

*Tariff levels are from 2011 and pre-date recent revisions in Nigeria and Kenya.
Most private sector executives view national targets and FiTs as the most powerful incentive mechanisms required to accelerate renewable energy development in the region. However, the full penetration of renewable energy into the African market largely will hinge on investment security underpinned by regulation. Feed-in-Tariffs (FiTs) are however now gaining ground in Africa. Sudan revised its FiT policy in 2010 to increase the array of renewable sources covered and tariffs to accommodate more projects, to attract more investors. FiTs could stimulate up to 1300 MW of installed power capacity for some African countries, and capacity levels are forecast to rise further as these tariffs allow the continued development of renewable sources and the corresponding expected decrease in long-term costs. Many countries in SSA have renewable potential that is many times their current demand for electricity, but most private sector executives view national targets and FiTs as the most powerful incentive mechanisms required to accelerate renewable energy development in the region.

Projected two-year (2013 – 2015) funding requirement by segment for Middle Africa’s power infrastructure, US$bn

Prospects for renewable energy development will hinge on regulation

Although still a smaller part of the energy mix in most countries, renewable energy accounts for almost 20% of total installed electricity capacity in Africa, and according to the UN, 66% of all new electricity generated in the region post 1998 was from renewable sources. This is largely due to use of hydroelectric power in many West and Central African countries for instance. Ghana, meanwhile, is leading the rest of West Africa in driving the renewable energy agenda with its 2011 Renewable Energy Act. The country plans to invest at least $1 billion in renewable energy projects in next 7 years to 2020. Costs tend to be high for renewable energy projects in Africa due to equipment imports, higher internal transport costs, import levies. Developing local manufacturing capacities and increasing the share of local content for renewable power generation projects can help reduce costs, which are predicted to decline over time. Some African countries are already taking the first steps towards creating economic value by promoting local equipment manufacturing, but financing is complex in the context of limited institutional know-how and many off-grid systems in SSA still do not qualify for state aid.

Sources: Ecobank Research, World Bank

However, the full penetration of renewable energy into the African market largely will hinge on investment security underpinned by regulation. Feed-in-Tariffs (FiTs) are however now gaining ground in Africa. For instance, Sudan revised its FiT policy in 2010 to increase the array of renewable sources covered and tariffs to accommodate more projects, to attract investors. FiTs could stimulate up to 1300 MW of installed power capacity for some African countries, and capacity levels are forecast to rise further as these tariffs allow the continued development of renewable sources and the corresponding expected decrease in long-term costs. Many countries in SSA have renewable potential that is many times their current demand for electricity, but most private sector executives view national targets and FiTs as the most powerful incentive mechanisms required to accelerate renewable energy development in the region.

Current renewable energy capacity in Sub-Saharan Africa (GW) & % Share of Power Generation in Sub-Sahara Africa by Fuel Type

Sources: Ecobank Research, World Bank, IRENA

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