Private Sector & Development

PROPARCO'S MAGAZINE

No. 18 / November 2013

Independent power producers: a solution for Africa?

Inadequate power capacity is holding back development in sub-Saharan Africa. Is independent power production the best solution to remedy the shortfall?

EDITORIAL BY CLAUDE PÉRIOU GENERAL DIRECTOR OF PROPARCO

Demand for electricity in sub-Saharan Africa is growing fast – driven primarily by economic growth and by policies for widening access to electricity – and yet production capacity has developed very little since the 1990s. Even today only 30% of the population has access to electricity – compared with 80% worldwide – and the economies of many African countries are severely disadvantaged by the quality and quantity of electricity at their disposal. The economies of Tanzania and Uganda, for example, lose an estimated 4% to 6% of GDP every year to power cuts. Now the international community is starting to take action to remedy this situation. Having been completely overlooked in the Millennium Development Goals, energy is now a priority for the UN and the EU, through the *Sustainable Energy for All* programme – which aims to increase access to energy while growing the proportion of renewable energy and improving energy efficiency.

According to estimates, production capacity would need to be boosted by around 7,000 megawatts every year from 2005 to 2015 in order to meet unsatisfied demand. This would require an annual investment of around USD 40 billion – whereas current investment is estimated at just USD 4.6 billion per year. Private investment in electricity production is one of the solutions to increase the financial resources available and improve performance in the electricity sector. Yet independent producers still represent just a tiny fraction of the players operating in this sector.

This issue of *Private Sector & Development* explores the benefits – and the requirements – of increased intervention in electricity production by the private sector. How have independent power generation projects established in Africa fared to date? What are the main obstacles in the way of their growth? Can private projects help to facilitate a shift towards renewable energies? Developing efficient public-private partnerships would seem to be the best – indeed perhaps the only – solution for confronting the major challenge of sub-Saharan Africa's energy deficit.

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Contributing elements to success of IPPs in sub-Saharan Africa

Independent Power Producers (IPPs) have contributed to power generation across sub-Saharan Africa, but there is still a long way to go. An analysis of the approximately 30 medium- to large-scale independent power projects that have taken root in sub-Saharan Africa to date highlights what are the essential components to foster IPPs development in the region.

Anton Eberhard and Katharine Nawaal Gratwick

Graduate School of Business (University of Cape Town)
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Only about 30 percent of the Sub-Saharan population has access to electricity[1]. It has been estimated that about 7,000 megawatts (MW) need to be added each year (2005-2015) to meet suppressed demand and provide additional capacity in the region. Such an investment would cost approximately USD 40 billion per year (Eberhard *et al*, 2011) out of which USD 27 billion would be for capital investment[2]. This latter figure is equivalent to 6.35 percent of Africa's GDP. Presently, funding for electricity capital expenditure is estimated at USD 4.6 billion a year, of which public sources contribute about 50 per cent, highlighting the urgent need for increased private investment, including public-private partnerships.

ANTON EBERHARD AND KATHARINE NAWAAL GRATWICK

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Across sub-Saharan Africa (SSA), the push towards private investment in electrical generation dates back to the early 1990s when multilateral and bilateral development institutions, which largely withdrew from funding state-owned projects, urged a number of countries to adopt plans to unbundle their power systems and introduce private participation and competition. Independent power producers (IPPs), namely, privately financed, greenfield generation, supported by non-recourse or limited recourse loans, with long-term power purchase agreements (PPA) with the state utility or another off-taker, became a priority within overall power sector reform. IPPs were considered a solution to persistent supply constraints, and could also potentially serve to benchmark state-owned supply and gradually introduce competition. Since the 1990s, approximately 30 such medium- to large-scale projects[3] have taken root across 11 countries. In total, approximately 4.7 gigawatts of IPP capacity have been added (Eberhard, A., 2013). However, the journey has not been smooth. The larger power sector reform programs were not far-reaching and IPPs represent only a fraction of the sector. A suite of country level and project level factors have emerged as playing a critical role in determining project success. Chief among them are: the manner in which planning, procurement and contracting are coherently linked and the role of development finance institutions along with the development origins of firms and credit

«IPPs represent only a fraction of the sector.»

[1] *As compared to one-half in South Asia and more than four-fifths in Latin America.*
[2] *The remainder is for operation and maintenance.*
[3] *This article deals with grid-connected projects, greater than 40 MW, with a long-term PPA with the utility, which have reached financial close and are under construction, operational, complete or concluded as of the end of 2Q2013. Although not included in this analysis, there are approximately 30 IPPs, each less than 40 MW, totaling 550 MW, also grid-connected, with long-term PPAs making a considerable contribution to the energy landscape across SSA. South Africa is also in the process of procuring 3.75 GW in renewable IPPs, over 3 tender rounds (with the first two rounds resulting in 2.5 GW), encompassing 47 discrete projects, totaling approximately USD 9 billion in investment, which represents Africa's largest renewable energy program, largest IPP development, and potentially, most complex public private procurement to date. Detailed discussion is, however, beyond the scope of this paper.*

enhancements. There are a number of notable success stories, including in Kenya, South Africa, and potentially Nigeria, where policy innovations have replication potential in other sub-Saharan African countries and beyond.

Investment climate and clear regulation

IPP projects were developed in a challenging investment climate in a number of sub-Saharan countries. Less than a handful of African countries have investment grade ratings. So as to attract private investors, countries had to develop tax incentives. Currency conversion was also provided for virtually all projects. It is noteworthy, however, that although one would expect the investment incentives to drastically increase with the perceived risk (in contrast to other regions), such a pattern is not apparent. With demand for IPPs outweighing supply, it is not surprising that those countries with a better investment profile attracted more investors and ultimately were able to cement deals on terms more favorable to the host country. The key take-away is that a risk-reward balance needs to be offered to attract investors/lenders; that balance starts with a stable and predictable investment environment.

New policy frameworks and clear regulation also proved to be key elements for sustainable development of IPPs. Although most ▶▶▶

TABLE 1: AFRICAN IPPS ABOVE 40MW AS OF THE SECOND QUARTER OF 2013

Project	Country	Size MW	Fuel/cycle	Contract type	Contract (yrs)	COD
Dibamba	Cameroon	88	HFO/peaking plant	BOT	20	2009
Kribi	Cameroon	216	Natgas/open cycle	BOT	20	2012
CIPREL	Côte d'Ivoire	210+111	Natgas/open cycle	BOOT	19	1995/2009
Azito	Côte d'Ivoire	281+139	Natgas/open cycle	BOOT	24/20	2000/2015
Takoradi II	Ghana	220	Light crude/single cycle	BOOT	25	2000
Sunon Asogli	Ghana	200	Combustion engine	BOO	20	2010
CENIT Energy Ltd*	Ghana	126	Trifuel/open cycle	-	-	2012
Westmont	Kenya	46	Kerosene/gas	BOO	7	1997
Iberafrica	Kenya	44+12+52	HFO/diesel engine	BOO	7/15/25	1997/2000/2009
OrPower4	Kenya	48+36	Geothermal	BOO	20	2000/2009
Tsavo	Kenya	74	HFO/diesel engine	BOO	20	2001
Rabai	Kenya	90	HFO	BOOT	20	2009
Thika Thermal Power	Kenya	87	HFO/diesel engine	BOO	20	under constr.
Triumph (Athi River)	Kenya	81	HFO/diesel engine	BOO	20	under constr.
AES Barge	Nigeria	270	Natgas/open cycle	BOO	13	2001
Okpai	Nigera	450	Natgas/combined cycle	BOO	20	2005
Afam VI	Nigeria	630	Natgas/combined cycle	BOO	20	2008
Aba Integrated	Nigeria	141	Natgas	-	-	2013
Kivuwatt	Rwanda	100	Methane/gensets	BOO	25	tbd
GTi Dakar	Senegal	52	Diesel/nafta	BOOT	15	1999
Kounoune I	Senegal	68	HFO	BOO	15	2008
IPTL	Tanzania	100	HFO/diesel engine	BOO	20	1998
Songas	Tanzania	189	Natgas/open cycle	BOO	20	2004
Centrale Thermique de Lomé	Togo	100	Trifuel (thermal)	BOOT	25	2010
Namanve	Uganda	20+30	HFO	BOOT	6	2009/2012
Bujagali	Uganda	250	Hydro	BOT	30	2011
Tororo**	Uganda	50	Diesel	BOO	-	2012
Itezhi Tezhi	Zambia	120	Hydro	BOOT	25	expd. 2014

BOT: Build-operate-transfer / BOOT: Build-own-operate-transfer / BOO: Build-own-operate / HFO: Heavy Fuel Oil

Mauritius, Cap Verde and South Africa have not been included in this sample.

**CENIT Energy, also previously known as Tema Osonor, while independent of VRA, is fully owned by Ghana's Social Security and National Insurance Trust company, thus strictly speaking only a quasi-IPP considering the public funds and sponsorship.*
***Capacity addition made to Tororo in 2012 (up from 20 MW, which dated to 2009).*

Source: Gratwick, K.N., Eberhard, A., 2011.

▶▶▶ countries have introduced legislation to allow for private generation, few have actually realized a clear and coherent policy framework. Besides, the incumbent state-owned utility continues to play a key role in the sector. IPPs are gradually being introduced but nowhere in Africa is the standard reform model for power sector reform being adopted fully, namely, unbundling of generation, transmission and distribution, and the introduction of competition and private sector participation at all levels (UN-ECA/UNEP, 2007; Malgas *et al*., 2007; Gratwick, K.N., Eberhard, A., 2008). However, nearly all countries which have started implementing reforms have established independent regulators, which are intended to address some of the risk that IPPs face such as arbitrary changes to rules or too much regulatory discretion in price reviews. Independent regulators also contribute to increasing overall transparency in what is expected from the investors. The presence of a regulator is not in itself a defining factor in attracting IPPs but helps ensure positive outcomes for host country and investor alike.

Linking planning, procurement and contracting

Intricately connected to sound policy frameworks are coherent power sector plans, which are linked to procurement and contracting. Ideally, these includes a number of core components: setting a reliability standard for energy security; completion of detailed supply and demand forecasts; a least-cost plan with alternative scenarios; clarifying how new generation production will be split between the private and public sectors; and the requisite bidding and procurement processes for new builds. Among the most important aspects of coherent power sector planning is vesting planning and procurement in one empowered agency to ensure that implementation takes place with minimal mishaps (Malgas, I., Eberhard, A., 2011). Kenya provides a good example of how responsibility for these functions may be allocated and institutionalized (see Box).

However, all too often, plans do not translate into timely initiation of competitive bid processes for new plants; and often there is insufficient capacity to negotiate with winning bidders or to conclude sustainable contracts. Transaction advisers may be appointed, but often there is little continuity over the long term. Hybrid power markets, with a mixed presence of private and public sector players, give rise to these new challenges and explicit policies, governance and institutional arrangements need to be developed to assign responsibility for planning, procurement and contracting of new power generation capacity. Effective linkages between these three functions also need to be established. In evidence are examples of demand and supply not being accurately forecast due partly to extended droughts, which in turn necessitated fast-tracking IPPs. Generally, the speed has been at a cost. Although it is easy in hindsight to accuse stakeholders of acting imprudently in the face of emergencies, the actual conditions of load-shedding and shortages appear to have provided few alternatives (Eberhard *et al*., 2011)[4]. However, better organization and planning upstream could have limited such situations.

Appropriate fuel supply and power purchase agreements (PPA)

The availability of competitively priced fuel supplies has also emerged as a key factor in how IPPs are perceived, in large part because fuel is generally a pass-through cost to the utility and in many cases to the final consumer as well. IPPs have helped countries to achieve greater fuel diversification; however, when their costs were compared with state-owned, generally amortized hydropower, they were seen to be largely more expensive, due partly to the fuel charge. The public perception is that IPPs drive prices up, which means that gaining public support for such projects is all the more challenging. When IPPs use fuel that is cheaper than the incumbent fuel, they have a greater chance of success.

The other key contract is the PPA. All the projects evaluated had long-term PPAs with the incumbent state-owned utility to secure revenue flows for debt and equity providers. The PPA has been a central document[5] and in certain cases, it has been the focal point of the discussions when deals have been considered out of balance.

Favorable debt and equity arrangements

Foreign firms have been the dominant players in SSA's IPPs. This should not be surprising, given the limited capital available. But a more revealing aspect than the nationality of the firm appears to be its prior experience in a country and the development origin of the investor. Globeleq, IPS and Aldwych Interna-

[4] The cost of emergency supply is indeed still less than the cost of no power. In terms of assessing the overall impact, "the estimates of the value of lost load or, unserved energy, and power outages in the countries in Sub-Saharan Africa constitute an average of 2.1 percent of GDP".

[5] In addition to indicating who would buy the power, the PPA details how much power capacity would be available as well as capacity and energy charges. How plants will be dispatched, fuel metering, interconnection, insurance, force majeure, transfer, termination, change of legal provisions, refinancing arrangements and dispute resolution are generally all clearly laid out as well. Risk mitigation provisions in the PPA stipulate penalties when the plants do not produce, as well as the ultimate sanctions when the plants fail, together with buy-out provisions.

tional, for example, all emerged from agencies with strong commitments to social and economic development. Globeleq remains wholly owned by Actis, which originated from the private-sector promotion arm of the UK Department for International Development (DFID). IPS is the operating arm of the Aga Khan Fund for Economic Development (AKFED), investing only in projects with a high development impact. Aldwych International is an initiative of the Dutch development bank, FMO. Projects for these firms have to make commercial sense, but they must also serve a developmental function, helpful in the face of African risk. It is worth noting that almost none of the projects with involvement of firms with development origins have seen any changes in contract terms, which may signal a greater perceived balance by local stakeholders in the terms of the contracts as well as a better ability to withstand public pressure.

With debt financing often covering more than 70 per cent of total project costs, competitively-priced financing has also emerged as a key factor in successful projects. Possible approaches in the African cases lie in the involvement of development financial institutions (DFIs), credit enhancements, and some flexibility in terms and conditions that may allow for possible refinancing. The recipe for sustainability appears to be that the risk premium demanded by financiers or capped by the off-taker matches the actual country and project risks and is not inflated, *viz.*, the investment and development outcomes are largely in balance.

DFIs funding has tended to take longer to reach financial closure but it also brings clear benefits; among others, development institutions help maintain contracts and resist renegotiation in the face of external challenges such as Kenya's droughts when developers were pressured to reduce tariffs. The main drawback of foreign financing is that it is usually denominated in strong currencies, which imposes PPAs in the same currency with negative impacts on tariffs as local currencies devalue.

Credit enhancements and security arrangements

The underlying credit risk of the projects has been largely dealt with via a suite of credit enhancements such as escrow accounts, letters of comfort, partial or sovereign risk guarantees, political insurance, etc. Of the many different credit enhancements, it is sovereign guarantees that have been most commonly employed. Support from the government is still considered by developers and multilaterals as the first level of support (World Bank, 2010), even though, in no projects have the sovereign guarantees, political risk insurance (PRI) or partial risk guarantees (PRG) been invoked. Although the absence of sovereign guarantees usually hampers the ability to raise private finance, it is noteworthy that IPPs, which by their very definition imply private investment, have had such significant public involvement. On this, there has been very little evolution since the first set of IPPs, with all projects supported by a PPA and the credit risk largely carried by a government guarantee.

In conclusion, it may be helpful to reflect on the overall application of security arrangements and credit enhancements. Efforts must continue to close the initial gap between investors and host-country governments' perceptions and treatment of risks, or contract unraveling will continue. The means of closing the gap may not be only, or mainly, via increasing the sort of new protections, including PRGs or PRIs, and may instead lie in systematic treatment of the numerous contributing elements to success.

BOX: PLANNING, PROCUREMENT AND CONTRACTING: THE EXAMPLE OF KENYA

In Kenya, the electricity law assigns responsibility for electricity planning to the Energy Regulatory Commission (ERC). Recognizing that it does not have the internal capacity, resources or planning tools to develop detailed and up-to-date electricity plans, the ERC convenes and chairs a planning committee comprising relevant departments and state-owned enterprises. Kenya Power and Light Company (KPLC), with the assistance of the World Bank, assisted this committee in developing least-cost plans. KPLC was unbundled in 1997 from generation, for which KenGen is now responsible, and so has a neutral stance between the state utility, KenGen, and IPPs. The Energy Ministry allocates new-build opportunities to either KenGen or to a competitive bidding process for IPPs. KPLC has also been assigned responsibility for managing the procurement and contracting process for IPPs. Bid documentation and PPAs have largely been standardised and private-project sponsors now have a clearer understanding of how the process for procuring new power works in Kenya.

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Independent power generation: the Ivoirian model

Côte d'Ivoire was one of the first countries in sub-Saharan Africa to privatise its electricity sector and, today, independent producers play a significant role in the country's electricity generation. The country is now willing to prioritise hydroelectric projects, in order to balance the energetic mix. Yet, as demand grows, the private sector still offers substantial potential for independent operators.

Amidou Traoré

Chief Executive of Société des Énergies de Côte d'Ivoire

Côte d'Ivoire was the first sub-Saharan Africa nation to turn to the private sector to expand its electricity generation capacity when the government, on top of opening up electricity production to competition, established Compagnie Ivoirienne de l'Électricité (CIE) in 1990, granting it a concession covering the purchase, transmission and distribution of electricity. A second restructuring phase was launched in 1998 – this time primarily focused on making the sector more profitable. A last reform was launched in 2011, when the state-owned company Société des Énergies de Côte d'Ivoire (CI-ENERGIES) was created to plan and manage investments in the power sector (see Box). Private sector involvement in Côte d'Ivoire's electricity industry is not limited exclusively to power generation. The government has set in place an innovative model based on contracting the operation of the entire sector to a private company. Begun 1998, this model instigated a system of cascading payments for all producers – a key source of security for independent power producers (IPPs). This model enabled private and public power generation to continue even throughout the political crisis of 2010–2011.

AMIDOU TRAORÉ

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At the official opening of the Aggreko thermal power plant in July 2013, Côte d'Ivoire's prime minister stated that his country's aim was to double its power generation capacity by 2020. This impressive increase in capacity, a response to growing demand, cannot, however, be achieved without the involvement of the private sector.

The private sector's growing share of power generation

The oil crises of 1973 and 1979 reaffirmed Côte d'Ivoire's decision to prioritise hydroelectric power production – dams at Kossou (174 MW), Taabo (210 MW) and Buyo (165 MW) became operational in 1972, 1979 and 1980 respectively. As a result, Énergie Électrique de la Côte d'Ivoire (EECI), the national company responsible for investment and operations, was able to fulfil more than 80 per cent of the national demand for electricity at a relatively low cost in years of good rainfall conditions. The drought of 1983–1984, however, forced Côte d'Ivoire to rebalance its energy mix. In consequence, EECI urgently commissioned a 100 MW gas turbine power plant at Vridi, but the increase in production costs from this led to a financial deficit that dogged EECI until 1990. That year Côte d'Ivoire decided to privatise its electricity sector, created CIE and contracted this new organisation for the national generation, transmission, distribution, export and import of electrical energy – with the aim of ensuring the sector's financial recovery. EECI remained in charge of planning and contracting investments. By 1994 demand for electrical energy had increased significantly, driven by the economic recovery that followed the devaluation of the CFA franc. Thus the risk of load-shedding and a lack of government funds prompted Côte d'Ivoire, to turn to IPPs to boost the country's capacity. On 20 July 1994 an agreement was signed with Compagnie Ivoirienne de Production d'Électricité (CIPREL) for the con-

« The country's aim was to double its power generation capacity by 2020. »

struction, operation and eventual transfer of ownership of a 200MW thermal power plant, and then in September 1997, a contract was concluded with Azito Énergie for the development of a 300MW natural gas-fired power plant in Azito. The installed capacity of these IPPs has been increased and the agreements have been extended several times – in 1997, 2010 and 2011 for CIPREL and in 1999, 2000 and 2013 for Azito.

Turning to IPPs in this way gave Côte d'Ivoire access to the electricity it needed to meet growing national demand. Private production has enabled the country to respond rapidly to demand while also positioning itself as a net exporter of electricity to other countries within the sub-region (Benin, Burkina Faso, Ghana, Mali and Togo). This positioning has been strengthened by the development of IPPs, highly reliable and presenting better availability rates. The figures for 2012 show total gross production of 6,949 GWh, energy exports of 610 GWh and a peak of 1,006 MW on the grid. The national coverage rate - the number of localities with access to electricity as a proportion of total localities - is 34 per cent while the access rate - the population living in localities with access to electricity as a proportion of the total population - is 74 per cent. This public-private partnership has also had the advantage of reducing national debt in the electricity production sector.

Key success factors and limitations

Overall Côte d'Ivoire's experience of using the private sector for electricity generation is a positive one. Several key success factors emerge from this experience. First of all it should be noted that payments to IPPs, which are collected by CIE, are secured by a law governing funding allocation in the Ivoirian electricity sector, with payments to IPPs prioritised in the management of financial flows. This arrangement has continued to function even in a crisis situation, thus allowing IPPs to continue to supply the power and energy necessary to cover demand.

The purchasing of the generated energy is governed by *take-or-pay* contracts[1], which guarantee the private producer sufficient revenues to make the project profitable, in accordance with the business plan produced as part of the feasibility study.

Finally, IPPs enjoy attractive tax incentives – in the form of tax exemption on their trading profits for several years – as well as various preferential customs tariffs.

Even so, this model does involve some constraints. *Take-or-pay* commitments included in the contracts lead to inflexibility in the management of generation facilities. The effect is that energy produced by the IPPs has to be purchased as a priority, an arrangement that can be cumbersome when it comes to developing a least cost development plan. A production base consisting only of IPPs with *take-or-pay* contracts is not a viable option as it would hamper the entire electricity generation system and put the grid security at risk.

In order to reduce their financial, operational and commercial risks, IPPs investors and their funders require a high level of involvement from the state through comfort letters and various securities. This is sometimes regarded as excessively onerous from the public sector perspective. Direct state investment in transmission and distribution infrastructure is required, too. Moreover, relatively long time scales are required for initiating private projects and securing their financing – these processes can extend over several months due to the legal requirements exacted by funders.

« Private production has enabled the country to respond rapidly to demand. »

It is also worth noting some unsuccessful experiences: agreements signed with private developers who were subsequently unable to secure a construction contract or adequate funding, as a result of which the agreements had to be terminated.

Thus, the key success factors of private

BOX: THE STRUCTURE OF CÔTE D'IVOIRE'S ELECTRICITY SECTOR

The company Énergie Électrique de Côte d'Ivoire (EECI), established in 1952, has historically been responsible for implementing government policy relating to electricity and water. The law of 29 July 1985, governing the generation, transmission and distribution of electricity, opened up the production sector in Côte d'Ivoire to private operators – expanding it to cover all authorised energy sources. Present-day government organisations include Société des Énergies de Côte d'Ivoire (CI-ENERGIES), responsible for managing assets in the electrical sector and planning and contracting investments, and the regulatory body Autorité Nationale de Régulation du Secteur de l'Électricité (ANARE). Compagnie Ivoirienne d'Électricité (CIE), the electricity sector operator, is a private company – as are the independent producers CIPREL, Azito, Aggreko and the natural gas producers (AFREN, Foxtrot, Canadian Natural Resources).

[1] *Take- or- pay: a clause in an electricity power purchase agreement by which the seller guarantees to supply the electricity to the buyer and the buyer guarantees, in return, to pay for a minimum quantity of energy, whether or not the buyer takes delivery of this that amount.*

Independent power producers: a solution for Africa?

►►► electricity generation are mainly the institutional framework, the support of the public sector, the choice of reliable operators and the sustainability of the projects.

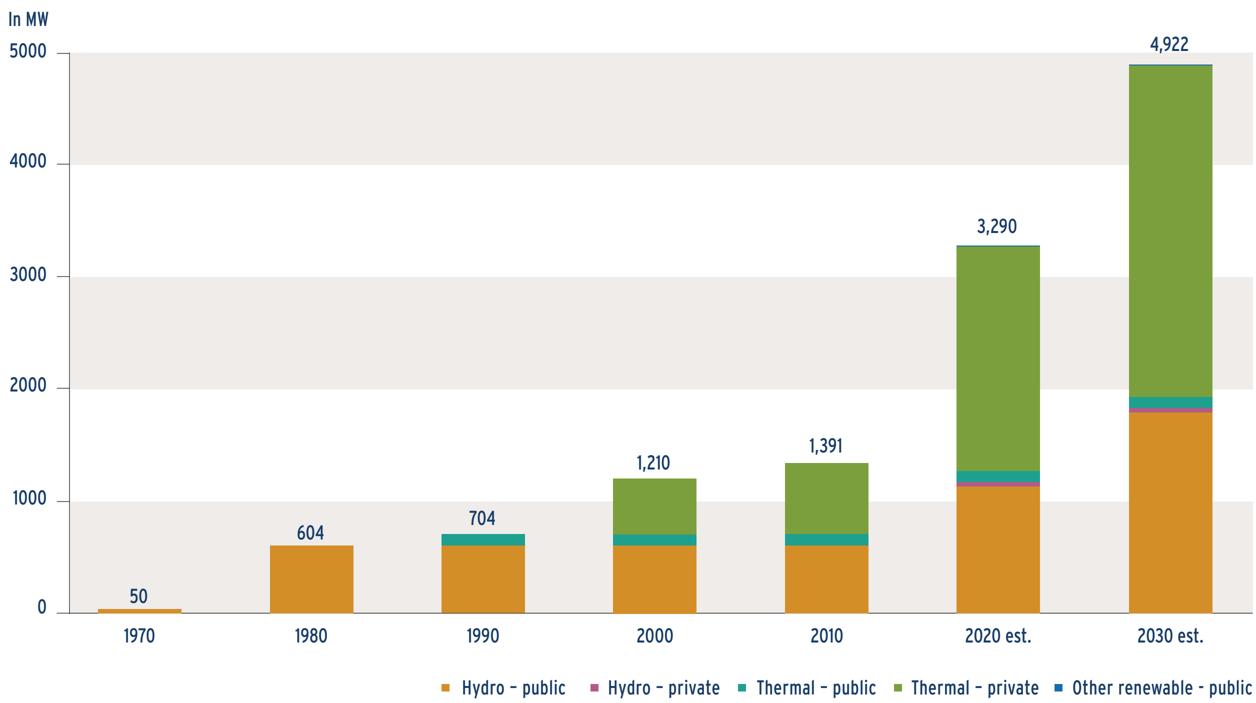
A SECTOR WITH SIGNIFICANT POTENTIAL

Côte d'Ivoire's installed capacity of 1,421 MW at 1 January 2013 is set to increase to 1,632 MW by the end of 2013 with the commissioning of Aggreko's 100 MW power station and the first phase of the CIPREL 4 project with a capacity of 111 MW. The country's aim is to double its early 2013 installed capacity by 2020 (Figure 1), with priority being given to hydroelectric projects, which generate renewable and less expensive energy, in the scheduling of medium- and long-term facilities. In order to develop this type of large-scale project, the government is willing to set up financing mechanisms based on public-private partnerships. In this context, the government has committed to rebalancing Côte d'Ivoire's electricity sector financially and to strengthen its investment capacity. This commitment of the state is reflected in the Strategic Action Plan developed by the Ministry of Petroleum and Energy of Côte d'Ivoire.

« The government has committed to rebalancing Côte d'Ivoire's electricity sector financially. »

The use of IPPs ensures that demand growth can also be met. Of the 1,500 MW of new projects that the country plans to commission by 2020, hydroelectric and thermal power plants developed by private operators accounts for around 85%. The government's goal of developing a balanced energy mix should encourage private hydroelectric production as well as the use of new and renewable sources of energy. The new Master Plan 2013-2030 which is currently in progress will explore all sources of potential production in Côte d'Ivoire. Besides, new laws that are about to be passed reflect this ambition of encouraging private sector initiatives, by defining a new regulatory framework for future investment in the sector. Finally, the energy requirements generated by large-scale projects (in the mining industries, for example) will increase the need for power. Côte d'Ivoire therefore offers significant potential for the development of independent electricity production. ●

FIGURE 1: INCREASE IN GENERATION CAPACITY IN CÔTE D'IVOIRE



Source: CI-ENERGIES, 2013

An inconvenient truth

Raising sub-Saharan Africa's electricity availability per person to the level of lower middle-income countries would potentially cost an unaffordable USD 400 billion. Private capital could help contribute to expanding the region's generation capacity cost-efficiently and rapidly. The African governments can do a lot to create a climate favourable to these private investments. One of the main measures to be taken is to strengthen their electrical sector. Charging the real price of electricity is a first step to achieve this goal.

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Few things are more important for economic progress and development than access to electricity. Today, for the 80 % of the world's population that has access to power, the magic of simply flicking a switch to light their houses or power their tools is long gone. But for more than 69 % of sub-Saharan African citizens, some 585 million people (IEA, 2011), access to electricity is still a distant dream. Excluding South Africa, the region's total installed capacity is only 28 gigawatts (GW), the same as the Netherlands', a country of just 17 million people (Foster, V., Briceño-Garmendia, C. 2010).

This reality elicits much hand wringing from the development community as the scale of the challenge is indeed daunting. Sub-Saharan Africa's annual electricity consumption per person stands at about 200 kilowatt hours (kWh)[2]; raising it to the level of lower middle income countries – typically about 700 kWh per year – would require at least 125 GW of additional generation capacity and the building of the associated transmission and distribution networks, at the cost of about USD 400 billion. Closing this gap in a decade would thus require investments of roughly USD 40 billion per year. As that is equivalent to 7.5–10 % of the continent's GDP, such an annual investment for each of the next 10 years is, at best, unlikely.

"For more than 69 % of sub-Saharan African citizens [...] access to electricity is still a distant dream."

Grants and development loans will not be enough either: total official development assistance (ODA) for infrastructure in Africa is about USD 3.5 billion per year (Foster, V., Briceño-Garmendia, C. 2010), while development banks and similar institutions provide around a further USD 30 billion[3] of loans annually. Even if a third of these flows of approximately USD 35 billion were allocated to power – an unlikely scenario – that USD 10-15 billion for power would still only be a third of what is needed.

So from where could the investment come? From the private sector naturally: in 2012, the leading 20 commercial banks arranged loans of USD 21.5 billion to power projects around the world; pre-crisis, in 2007, ►►►

BERTRAND HEYSCH DE LA BORDE AND YASSER CHARAFI

Bertrand Heysch de la Borde has more than 20 years' experience in infrastructure finance. He is the International Finance Corporation (IFC) manager responsible for its infrastructure operations in Sub-Saharan Africa, heading a team of 40 investment professionals. Before joining IFC in 2007, Bertrand was Managing Director, Head of Infrastructure Project Finance at Société Générale. He started his career at Agence Française de Développement (AFD)/ Proparco (Paris and Accra).

Yasser Charafi is an Investment Officer with IFC's Infrastructure Team for Africa based in Dakar, Senegal, in charge of investments in power and transport infrastructure. Yasser specializes in fixed transportation infrastructure (ports, airports and toll roads) as well as thermal and renewable power projects with a focus on project financing.

[1] The views and judgments contained in this article should not be attributed to, and do not necessarily represent the views of, IFC or its Board of Directors, or the World Bank or its Executive Directors, or the countries they represent
[2] Excluding South Africa.
[3] Authors' estimate (includes development banks and leading Exim banks)

Independent power producers: a solution for Africa?

▸▸▸ it was USD 45.5 billion. Closer to home, in the past year alone, the International Finance Corporation (IFC) arranged about USD 1.5 billion of financing for power projects in sub-Saharan Africa, catalyzing more than USD 3 billion of total investment, most of it jointly with Proparco, one of IFC's closest partners.

Private sector: a source of funds

It is clear that private capital should be a part of the solution for Africa to improve its citizens' access to power. Private capital could predominantly be directed towards more independent power producers (IPPs) whose role is now well established.

Independent power producers are more efficient. On average thermal power plants operated by state-owned national utilities in Africa rarely exceed 65% availability[4] while IPPs often exceed 90% – as private operators have clear incentives, they relentlessly focus on operational performance. Independent power producers also save governments large upfront costs allowing precious resources to be deployed elsewhere – the price tag of a 100 MW heavy fuel oil-fired plant is the same as that of about 50 well-equipped health clinics. They also deliver adequately priced power – the average cost is less than USD 0.05 per kWh[5] for thermal plants excluding fuel – and transfer construction and financing risks away from governments.

"Private capital should be a part of the solution for Africa to improve its citizens' access to power."

Yet, over the past three years, only about 10 private power projects were implemented in sub-Saharan Africa, excluding South Africa: less than one IPP per country per decade, with only nine countries out of 48 resorting to IPPs.

What holds private investment in power in Sub-Saharan Africa back?

While many reasons are often cited, we shall remain faithful to the principle of Occam's razor and postulate just two root causes that hold back private investment in power generation in sub-Saharan Africa, and particularly in IPPs. Firstly, governments seem reluctant to embrace the transformational impact of private investment in power generation; and, secondly, governments fail to ensure adequate cost recovery in and financial sustainability of their power sectors.

Before expanding on these two root causes, we must emphasize that good governance is a key precondition if IPPs are to thrive. By this we mean both governance in general terms – investors value visibility and clear rules – and also governance of the electricity sector. This is a complex sector in which finance, economics and social considerations mix, and for which competent management is an essential if private investment is to be attracted. Independent power producers cannot exist in a vacuum: they need favorable initial conditions.

Governments across the region remain reluctant to fully leverage the private sector's capital and capabilities for a number of reasons. In some instances, they still consider power generation a strategic sector that should remain in the state's hands. In some other countries, previous experience has led to negative perceptions of the private sector. Then, at times, governments see retaining public control of the sector as a way of postponing painful reform. And in other cases, governments are tempted by attractive concessional lending rates, grants or export credit terms, and become persuaded that IPPs could, comparatively, increase costs.

Further, a lack of acceptance of the fact that, in essence, power is a commodity and there is nothing really special about it lies behind an unwillingness to charge the true cost of power. It should be remembered that the capital cost of a power plant is roughly the same the world over, while variable costs, mainly the cost of fuel, depend on natural endowment and national availability. It is no cheaper to build a power plant in Africa than in Asia, Europe, Latin America or North America. Rather, the opposite is the case due to factors including a lack of economies of scale and the cost of transport and finance. Thus it follows that, after discounting the differences in natural-resource endowments, the cost of generating a kilowatt hour of electricity in Africa is at least as much as one generated in richer countries.

Pricing to match incomes

Since income levels are not the same everywhere around the world, affordability becomes a concern. In Africa, governments have responded to this by setting low tariffs and as a result, in many countries, the power sector has rapidly become financially unviable, dependent on large government subsidies to continue operating. This story is, sadly, unfolding across the continent: a recent International Monetary Fund (IMF) report on energy subsidies indicates that

[4] Authors' estimate (proprietary data). 'Availability' refers to the proportion of the time when a power plant is able to generate electricity.
[5] Select sample of projects from authors' data

in sub-Saharan Africa electricity tariffs allow the recovery of only about 70% of costs (IMF, 2013), whereas subsidies to the electricity sector represent on average 2.0% of GDP and 9.0% of total government revenues (IMF, 2013) – by contrast, spending on both health and education sectors in the region totals about 8% of GDP.

This focus on affordability, while legitimate, is too often approached narrowly and the allocation of such large subsidies to power is, simply put, questionable. Indeed, the affordability issue is fraught with misconceptions. It is worth remembering that when end-users lack electricity they resort to much more expensive alternatives such as kerosene at a cost of something in the region of USD 0.75 per kWh for lighting[6]. Or consider the considerable cost of a lack of power to the economy – that's why both businesses and private individuals that can afford it have private generators – usually producing power at a cost of more than USD 0.50 per kWh. And the price per kilowatt hour is not as relevant as many believe – yes, a kilowatt hour at USD 0.20 sounds a lot for the average African citizen, but what really matters is the total spend on electricity as a share of income. Because the average OECD citizen uses about 20 times more electricity than the average African citizen while having an income about 20 times higher, as a share of income, the two spend about the same proportion of their income on power. That is the real issue.

Subsidizing power is not good policy for two main reasons. Firstly, such subsidies are inequitable and socially regressive: they overwhelmingly benefit the rich – the IMF reports that the poorest 20% of the population typically only receives 9% of total electricity subsidies (IMF, 2013). And secondly, these subsidies divert scarce budgetary resources from more pro-poor spending – money spent on subsidizing power does not go, for example, to health care or education.

Africa's power-failure trap

The result of government unwillingness to make people pay the true cost of power drives credible investors away, especially IPPs. Why would they invest hundreds of millions of dollars when the off-taker – the utility or the government to whom power will be sold – does not collect enough from end-users to cover costs, leaving the investor with a significant risk of not being paid?

The central role that utilities play must also be highlighted. The failing power sector across Africa is largely alike: an underperforming utility is, almost without exception, at the heart of the failure, and all too often, alas, it is state-owned. A good utility plays a central role in helping stabilize a power sector, as the examples of Compagnie Ivoirienne d'Electricité (CIE) in the Ivory Coast, Umeme in Uganda, the Kenya Power and Lighting Company (KPLC), and to some extent AES-Sonel in Cameroon demonstrate. The professional management of these companies and their relentless attempts to reduce losses, collect from end-users and advocate financial sustainability have been instrumental in keeping their respective power sectors afloat. It should not come as a surprise that these four countries have also seen significant levels of IPP activity, including a few landmark projects – the Bujagali hydropower project in Uganda, the CIPREL thermal-energy development, the Azito natural-gas plant in the Ivory Coast and the 87 megawatt Thika power plant in Kenya.

" The result of government unwillingness to make people pay the true cost of power drives credible investors away. "

The two fundamental factors – a government's lack of a pro-private sector stance for power generation, and a financially unsustainable electricity sector – often interact to create a power-failure trap, which leads to a deteriorating quality of service, increased costs and the adverse selection of good private investors (Figure 1). And all start with a vulnerable utility.

The way forward

How can we get out of this trap? Fundamentally, by ensuring cost recovery in the sector: there is no escaping the simple but inconvenient truth that end-users should pay the real cost of power; and by recognizing that power generation is an activity best left to the private sector – just like telecommunications.

Independent power producers, by and large, hold out the best hope of expanding sub-Saharan Africa's generation capacity ▸▸▸

[6] *Authors' estimate on the basis of a liter of kerosene at USD 0.5/liter, 10 kWh/liter of kerosene of calorific content and an efficiency of about 0.1 lumens/watt.*

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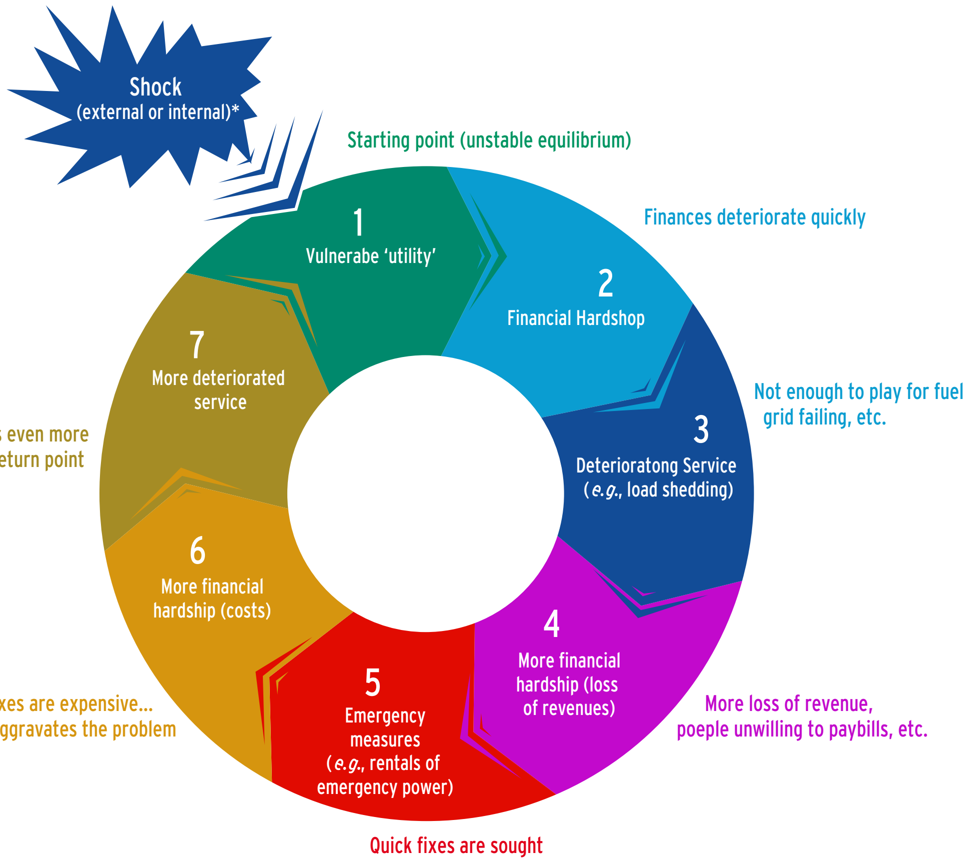
IFC is the private sector arm of the World Bank Group and one of the leading multilateral financiers of power projects in Africa. IFC invests (through debt, equity and quasi-equity) across the entire power sector value chain, in transmission, generation and distribution. IFC also acts as project co-developer through its InfraVentures fund. Over its last fiscal year, IFC arranged about USD 1.5 billion of financing for Africa's power sector and catalyzed about USD 3 billion of private investment.

Independent power producers: a solution for Africa?

FIGURE 1: AFRICA'S POWER-FAILURE TRAP



**Maybe be external (e.g. oil prices) or internal (heavy, growth, failing grid, etc.) or both.*
Source: Figure realized by the authors for Private Sector & Development

▸▸▸ cost-efficiently and rapidly. They are the low hanging fruit of public-private partnerships in infrastructure as IPPs are, in relative terms, easy to tender and structure; there is an ample supply of best-practice contractual arrangements that have stood the test of time and are well understood by both investors and financiers; there is no shortage of financing for well-structured IPPs promoted by reputable sponsors; and they (usually) deliver.

> *"All IPPs require is a welcoming host country and the reasonable certainty they will be paid."*

All IPPs require is a welcoming host country and the reasonable certainty they will be paid. If these two conditions are met, the private sector will help power Africans – just as private mobile operators have connected them.

Examples from Cameroon, Ivory Coast, Kenya, South Africa and Uganda all illustrate this. The Ivory Coast has attracted more than USD 1 billion of investment in 18 months to increase the country's generation capacity by 30%. Uganda halved its cost of power and tripled its access to power rate thanks largely to Bujagali and Umeme, the privatized utility. Kenya is massively increasing capacity, both thermal and renewables thanks to a slew of new IPPs – more than five in the past two years – and South Africa leveraged IPPs to rapidly ramp-up its renewable solar and wind capacity through more than 12 IPPs.

If countries build the investment fundamentals for IPPs, the investors and financiers, will come. ●

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Driving growth by providing economically sustainable power

Globeleq focuses on independent power projects (IPPs) in the emerging markets of Africa and Central America. The company is dedicated to enabling growth; the good performance of its operations; delivery of its projects on time and on budget; and participation in future development opportunities. It aims to help countries drive economic growth by providing economically sustainable electricity, using established IPP processes, such as those developed in Kenya, Nigeria and South Africa.

Mikael Karlsson

Chief Executive Officer, Globeleq

Globeleq was formed in 2002 to focus on independent power projects (IPPs) in emerging markets. At that time, most believed aid was a necessary part of developing the African continent and reducing poverty. Over time, however, a slow but general realisation has emerged that change would best come through the creation of economically-sustainable businesses which support economic development through private investment. Some countries have successfully created a suitable environment for private investment that encourages growth, some are working on it, others, though, have not made changes. The fact remains, however, that demand for energy outstrips supply, holding back economic development over much of the continent.

MIKAEL KARLSSON

Mikael Karlsson's 19 years' experience in infrastructure began at ABB Equity Ventures, which developed and invested in independent power projects. His association with Globeleq started in 2002 and he was appointed CEO in 2009. Mikael is also a co-founder of InfraInvest, which advised on energy and infrastructure investments and led to the inception of Arox Infrastructure and Arox Capital, focusing on the management of infrastructure funds.

Leading independent power projects in Africa

Globeleq has rapidly expanded its activities in the past two years, undertaking construction of 520 MW of new generation capacity and begun the 139 MW expansion of an existing operation. The company typically invests in assets with operating capacities of 50–500 MW and targets equity investment of USD 50-150 million per asset in its target regions. Our return targets reflect market dynamics and the risk profile of a project; where the sector is stable, government support is strong and the process clear, our return requirements are likely to be lower. The company is not constrained by technology and pursues opportunities across the whole spectrum of power plant technologies and fuel types, including renewables.

Globeleq targets countries that demonstrate commitment to private power producers through a transparent procurement process, backed by a coherent energy plan. Other investment criteria include the ability to contract long-term power-purchase agreements (PPAs), fairly priced and sustainable long-term tariffs, and credit-worthy off-takers. We try to attain majority ownership and operational control, with day-to-day commercial, operational and maintenance responsibility. Even when these criteria are met, Globeleq recognises that progressing projects can be challenging and takes time.

In Tanzania, Globeleq's Songas project was the country's first natural-gas-to-power project, fully supported by the government, sector participants, legislation, a newly appointed regulator and the World Bank. Originally scheduled to reach financial close in 1997, the project was suspended for four years when another IPP started and became marred by allegations of high-level corruption. Confidence in IPPs and the sector was eventually restored and the integrated gas-to-power facility began operation in 2004. An expansion project in 2005 has added further capacity and consequently Songas has saved Tanzania billions of dollars in imported fuel-oil costs and enabled the construction of new gas-fired generation facilities. Tanzania, however, has fewer potential investors in its power sector than ▸▸▸

Independent power producers: a solution for Africa?

▸▸▸ Kenya due to tariffs being held below cost-reflective levels, illiquidity in the sector and sporadic payment delays.

In late 2010, Globeleq increased its stake in the 288 MW Azito plant in Côte d'Ivoire, with a view of immediately expanding and converting the facility to a more efficient combined-cycle plant. Shortly after financial close, an election was followed by six months of civil unrest, temporarily setting back much of the stability and investment climate which had existed since privatisation of the sector began in the early 1990's.

Conflict of any kind usually chases investment away. However, after it subsided, the newly elected government committed to address the country's power deficit and continued to pursue the project with industry sector participants, lenders and international investors. Construction began in February 2013 and an additional 139 MW will be added to the grid in 2015. Having a fully committed and supportive government, a dedicated industry sector with established policies, and legislation created to achieve long-term sustainability, ensures this and other IPP's on-going success.

"Globeleq looks for projects in markets with government support."

Globeleq looks for projects in markets with government support – both from a political and contractual perspective. Another area is the long-term participation of multi-lateral and bilateral development agencies in the projects. Often their participation is non-negotiable – outside of South Africa it is hard to find long-term finance other than from these institutions – but the corollary is the political halo created by their participation.

Contrast with Central America

In Central America, where Globeleq's majority-owned subsidiary, Globeleq Mesoamerica Energy is the region's leading wind-energy producer, its investment criteria and IPP principles are similar.

The development of the energy-sector in this region is very different from in Africa, with private power driving growth. On average in the region, an estimated 63 per cent of energy generation is provided by approximately 20 IPPs. Compare this to markets in Africa where Kenya and Nigeria lead the way with four or five significantly sized IPPs. The success of IPPs in Central America has been driven largely by government commitment to the private sector as the primary driver of the energy sector, and to associated transparent procurement processes together with the sustainable regulation required for long-term success.

In addition, renewable energy in Central America is high on the agenda with an ample supply of natural resources and a commitment to sustainable energy development. This is reflected in renewable-specific structuring mechanisms such as net metering, economically viable feed-in tariffs and robust renewable-energy production laws. Though Africa has equally abundant renewable resources, many countries are yet to put in place economically-viable feed-in tariffs or to structure processes specifically aligned to renewable projects.

African specificities

Africa has historically been the slowest moving of Globeleq markets, with continuing sector economic problems across the majority of the continent. There are, however, signs of change with South Africa, Nigeria and Kenya formally recognising the need for private-sector investment. When the South African government launched its Renewable Energy IPP Procurement Programme (REIPPP) in 2010 to add 3,725 MW to the national grid with aggressive first-round bid deadlines, the perceived challenges would have daunted any seasoned IPP developer. But the process was successful – 28 new renewable power projects with a capacity of 1,416 MW were awarded in the first round. Of these, Globeleq and its consortium members were successful in the 138 MW Jeffreys Bay Wind Farm and the 50 MW Droogfontein and 50 MW De Aar solar power projects. The REIPPPP is being lauded around the world as revolutionary with the first two rounds[1] mobilising USD 9.5 billion of investments, mainly provided by the private sector. Why did it work so well? The government fully supported the initiative and established a transparent process with clear guidelines, ensuring the best technical, legal and project finance advisors were assigned to the programme. Strong treasury support – effectively a guarantee of the public utility's obligations – gave lenders and sponsors investor confidence. To ensure power was competitive, af-

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Globeleq is wholly owned by Actis, the emerging market's leading private equity firm. In total, the company has invested more than USD 1.3 billion of equity across 41 different power projects. Since 2007, it has focussed on sub-Saharan Africa and Central America, investing to enhance performance of existing assets, or develop and construct new power projects. In the past 2 years, Globeleq has undertaken construction of 520 MW of new generation and commenced a 139 MW expansion of an existing operation.

[1] *The second round has been completed in May 2013 with 19 projects totaling 1 044MW*

fordable and sustainable, South Africa opted for a competitive-bid process rather than a feed-in tariff. Additionally, the provision of standardised bilateral agreements included a long-term PPA with the national utility. Social and economic development targets were built in to the deal, ensuring local rural communities benefit from each renewable project.

In Nigeria, privatisation and restructuring of the electricity sector has huge potential. With around 170 million people, yet with an installed capacity of only around 4,000 MW, most people rely on self-generation. After years of false starts, broken promises and corruption, the sector seems to be moving in the right direction with various initiatives and bodies set up to attract private investors.

In 2012, the government approved USD 2.3 billion in bids for generation and distribution. Power produced will be purchased through long-term PPAs with the Nigerian Bulk Electricity Trading Company, backed by risk guarantees provided by the World Bank. A multi-year tariff order has been put in place to move tariffs to cost-reflective levels in the medium term, with the availability/reliability of supply through long-term gas-supply arrangements a work in progress. There are substantial hurdles still to be overcome, so only time can tell whether this renewed political impetus will be carried through to a successful privatisation and restructuring of the sector.

Relying on hydro- and thermal-power generation, Kenya has set goals, with supporting legislation, to diversify its renewable energy portfolio by adding geothermal –1 GW over next 3–5 years – and wind energy. It has introduced feed-in tariffs for renewables and the programme is well supported by the World Bank and the African Development Bank. Competitive tenders for geothermal plants are being overseen by the Geothermal Development Corporation and Kengen, the dominant majority state-owned generation utility, both of whom seek to work within the established feed-in tariff for geothermal power.

Main hurdles

Aside from these three African economic powerhouses, energy-sector procurement programmes are still slow and lack transparency. Even countries with enormous energy resources continue to have electricity shortfalls. There are three main ways of procurement – bid, feed-in tariffs and bilateral regulated. All can be successful but only if there are transparent, clear processes backed by legislation. Full commitment and understanding by government in support of financially-healthy energy sectors and private sector participation needs to be present, while tariffs must be cost and risk reflective.

Generally, the sector remains extremely political with some countries insisting that government-owned utilities be responsible for power-sector growth, alongside subsidised tariffs. Transparent processes and legislative frameworks and mechanisms to create favourable private-investment environments are non-existent in many countries, as is the existence of credit-worthy off-takers. Securing the support of financial institutions and the confidence of private investors still requires credit support from, for example the Multilateral Investment Guarantee Agency, and the International Development Association's Partial Risk Guarantee. Globeleq assesses the level of credit support on a project-by-project basis, taking the risks of the project and the sector into account.

"There is a slowly emerging turning point for Africa's power sector."

In addition, there is an underlying perception that international investment results in little or no benefits for the local economy. This is palpably not true when one takes into account the substantial direct and indirect benefits of providing reliable and sustainably-priced energy otherwise not available to energy hungry markets, thus driving economic and social growth. The South African REIPPP has shown that specific socio-economic development targets can be secured if well planned.

Looking forward

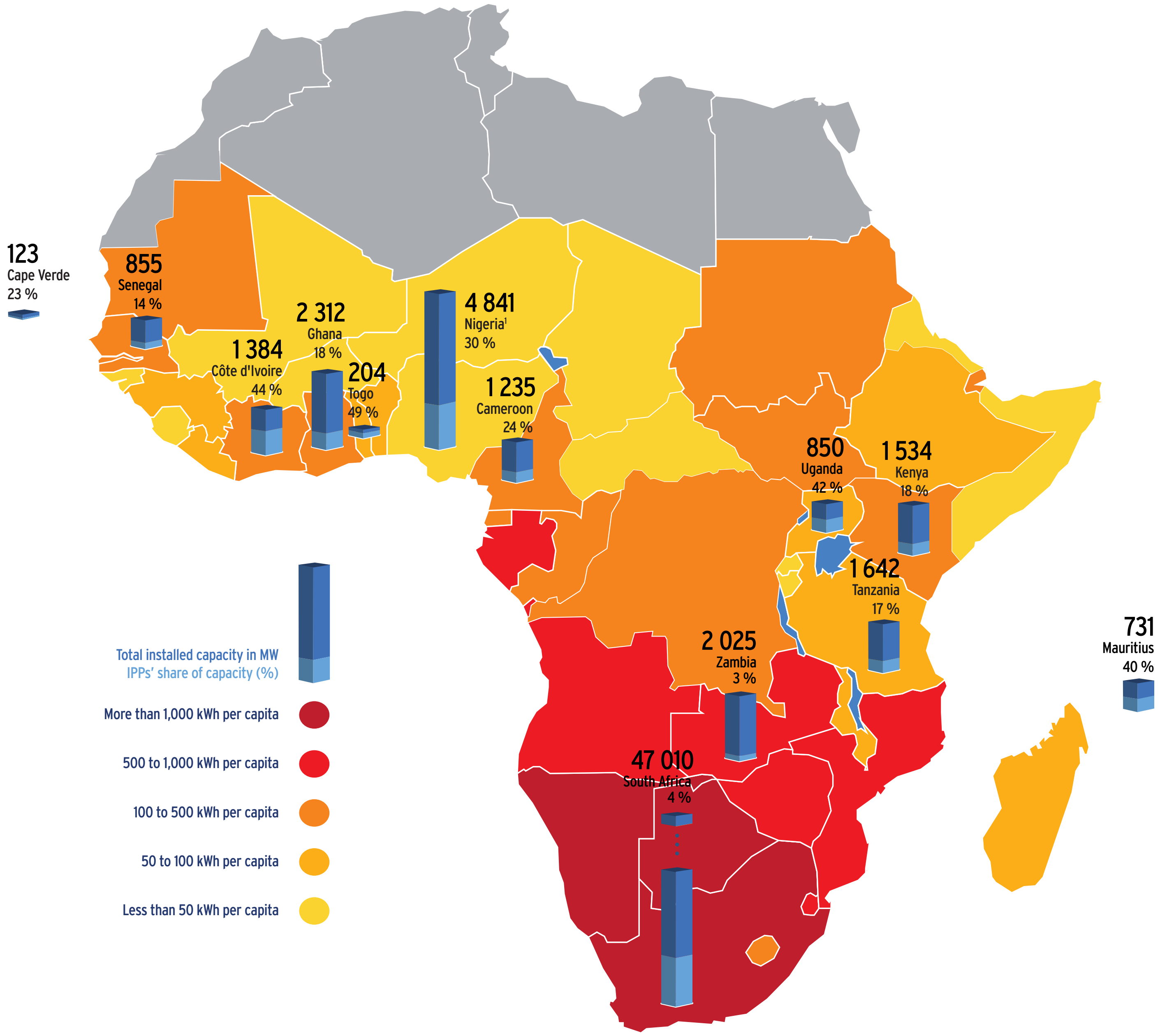
Globeleq is optimistic for the future of sub-Saharan Africa and believes that currently there is a slowly emerging turning point for Africa's power sector. The company is committed to playing its part in continuing growth; the good performance of its existing operations; near-term delivery of its projects under construction on time and on budget; and participation in future development opportunities.

In the short term, with the right investment environment already in place, Globeleq is looking forward to the continued success of South Africa's REIPPP. All indicators point to good progress for restructuring of the power sector in Nigeria and further opportunities being made available through the bid process in Kenya.

More broadly, it is hoped other countries in sub-Saharan Africa will benefit by following the successful processes of these three countries and enabling procurement of more IPP projects to provide economically sustainable electricity, driving economic growth across the continent. ●

Sub-Saharan Africa's power capacity shortfall is holding back economic development in the sub-continent. Despite the region's huge energy potential, capacity expansion is painfully slow. The funding required to remedy the deficit is substantial and governments do not have the necessary resources at their disposal. In this context the private sector clearly has a key role to play.

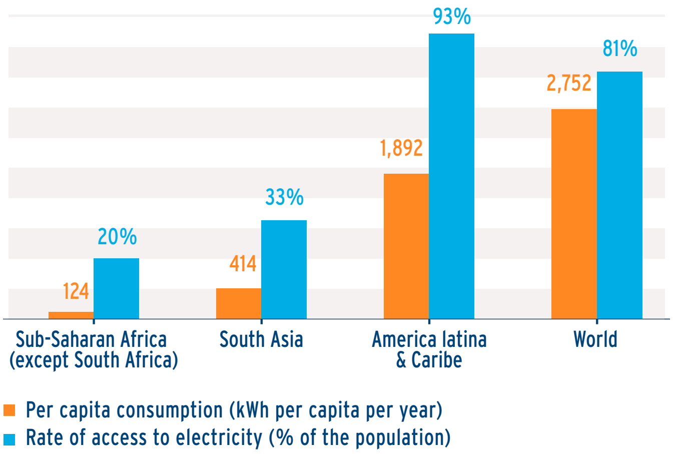
Electricity consumption and private sector share in electricity installed capacities in sub-Saharan Africa, 2013*



[1] Available installed capacity

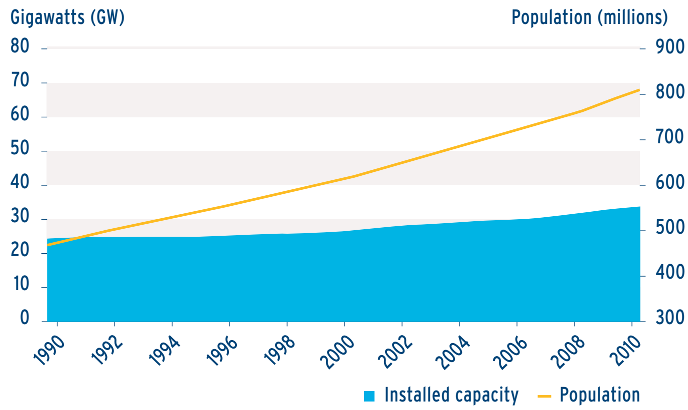
Source : CIA, 2009 - World Bank, 2010 ; Proparco / Private Sector & Development, 2013

Access to electricity and consumption by region, 2009*



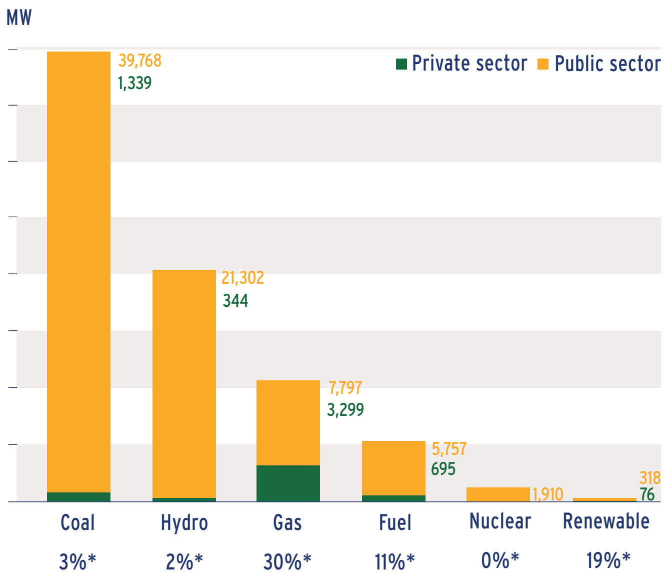
Source: World Bank, 2009 ; IEA, 2009 ; AICD, 2008

Installed capacity of sub-Saharan Africa (excluding South Africa), 1990-2010



Source : EIA 2012

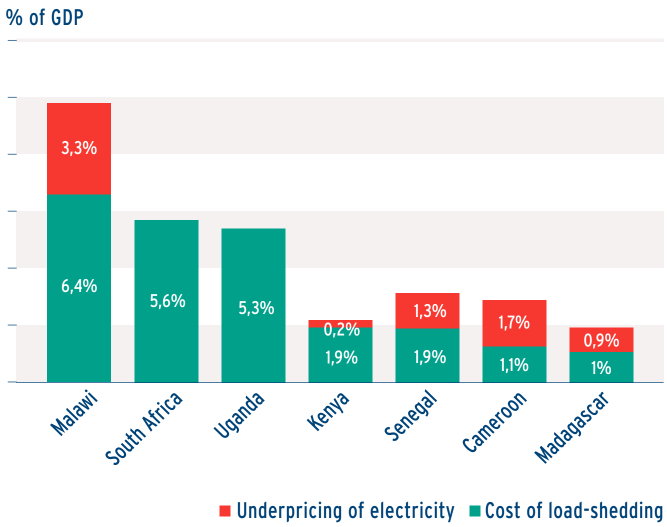
Capacity by energy type, 2013



* Private as a % of total
South Africa alone accounts for 96% of total coal installed capacity in sub-saharan Africa (including 100% of private capacities) above data exclude cogeneration

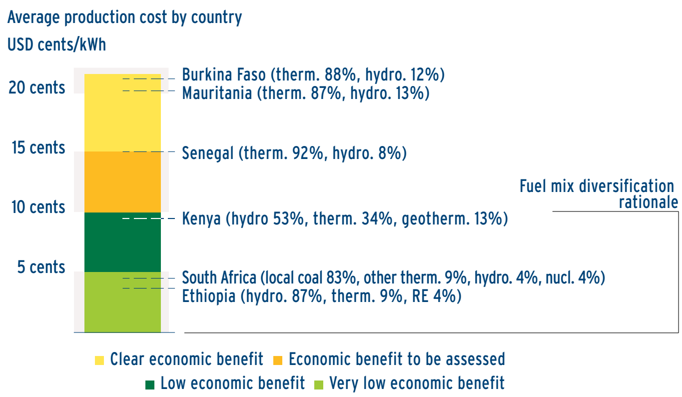
Source : Proparco / Private Sector & Development, 2013

Impact of power production system weaknesses on GDP, 2008



Source : Eberhard et al., 2008 ; Briceño-Garmendia et al., 2008

Economic benefit of REs (wind, solar PV) 2013*



Source : Nodalis, Axenne, 2013 ; Nodalis, Equilao, 2012 ; Proparco, 2013

* Data based on estimates from different sources and years.

Infrastructure needs and financing sources in sub-Saharan Africa, 2008

USD billion per year

Infrastructure sector	Operation and maintenance expenditure	Capital expenditure		Total expenditure requirement	Financing shortfall
	Public sector	Public sector and development aid	Private sector		
Electricity	7	4,1	0,5	40,8	29,2
Transport	7,8	7,3	1,1	18,2	1,9
ICT	2	1,3	5,7	9	0
Water and sanitation	3,1	2,5	2,1	21,9	14,3
TOTAL	19,9	15,2	9,4	89,9	45,4

Source : Briceño-Garmendia et al., 2008

Assessing the impacts of new IPPs at country level? Case study on Kenya

Independent power producer (IPP) investments are making a real contribution to increasing the provision of electricity in Kenya, and in reducing outages. This analysis demonstrates the development potential of IPPs, and provides guidance, particularly the importance of cooperation between public and private bodies, for other developing countries looking to leverage private investment to alleviate shortages and increase the availability of power.

Jason Wendle

Associate Partner, Dalberg Global Development Advisors

The development impact of new energy generation capacity in a country is proportional to the severity of current power constraints on the economy. For an independent power producer (IPP) to make an impact, it must, where demand exceeds current supply, provide power beyond what public entities could develop, or displace a higher-cost source of energy. Based on these criteria, the case for the positive impact of IPPs on Kenya's energy sector and economy is clear, though within IPP production there is a debate to be had regarding optimal energy sources.

At a macro level, lack of energy is a frequently cited as a constraint to Kenya's growth: power outages cost the Kenyan economy an estimated 7 % in lost private sector sales revenue, 2 % of total GDP and 1.5 % of GDP growth (Ministry of Energy, 2011). Though generation capacity is not the only source of power problems, insufficient supply (exacerbated by droughts) has led to widespread outages due to load shedding in two of the past four calendar years. Another sign of a power generation bottleneck is that Kenya has not been able to shake its dependence on costly diesel-generated emergency power. Figure 1 illustrates how increased IPP generation has partially, but not completely, helped displace emergency power from Kenya's generation mix.

Given that the majority of the population is not yet on the grid, and power demand is projected to grow at 6 % a year in the immediate future (ERC, 2013) and over 10 % in the long term (Ministry of Energy, 2011), the state-owned generation company, KenGen, is developing generation capacity as fast as possible within its organizational and capital constraints. In this context, every megawatt (MW) installed by IPPs adds to rather than displaces public investment.

> *"Power outages cost the Kenyan economy (…) 2 % of total GDP."*

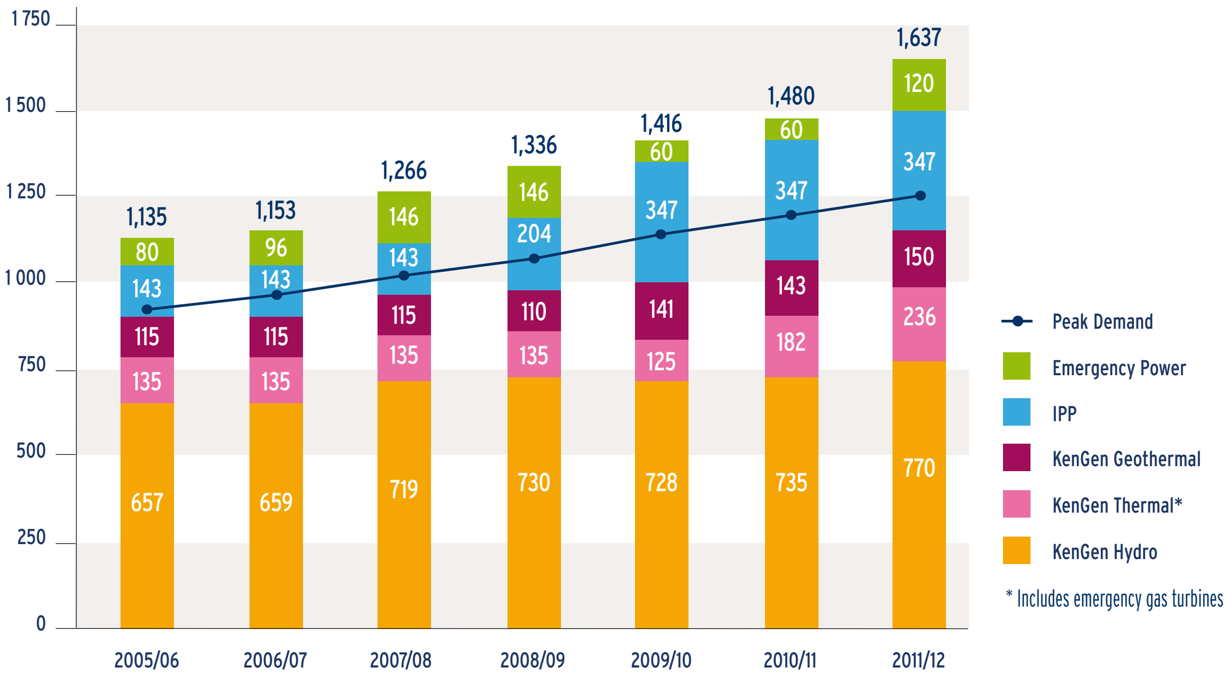
Assessing the impacts of IPPs

Analyzing the impact of a particular IPP project requires multiple methodologies to cover the range of desired outcomes for different stakeholders and at different levels in the economy. The first step, in either an *ex-ante* or *ex-post* assessment, is to map these desired outcomes. In *ex-post* assessments of 2009 investments in Rabai Power, a thermal IPP, and Olkaria III, a geothermal IPP, in Kenya, a team from Dalberg used a "theory-of-change" exercise to map the distinct channels through which each investment was expected to achieve desired outcomes. These outcomes included the diversification of Kenya's power supply, increased private power generation, minimized carbon emis-

JASON WENDLE

Jason Wendle is an Associate Partner in the Nairobi office of Dalberg Global Development Advisors, providing clients with strategy and policy advice. He has published or presented studies on topics that include energy sector investment, SME finance, and impact verification methodologies. Jason earned his Master's in Public Administration in International Development from Harvard University's Kennedy School of Government.

FIGURE 1: KENYA'S PEAK ELECTRICITY DEMAND AND END-OF-PERIOD GENERATION CAPACITY BY SOURCE (MW)



Note: Load factors[1] for hydro power range between 34 % and 60 % during this time, which is why capacity cannot cover demand
Source: KPLC, 2006-2012

sions, returns for investors and income for workers, and positive community/social effects. We defined indicators to measure these outcomes, such as a reduction in the price of energy, increased government revenues and reduced load shedding.

Quantitative and qualitative approaches used to assess each indicator included calculating the change in electricity prices due to lower-cost generation; soliciting ratings of the relative reliability of various power plants from the off-taker, Kenya Power and Lighting Company (KPLC); and interviewing local community members about changes in their lives linked to the new power plant. In this way, the assessment can both compare different IPP projects – for example to identify best practices in engaging the local community – and compare against the case where no new power plant is built at all. The latter scenario also forms the basis for a simple calculation of an economic rate of return (ERR)[2].

The economic impact

In Kenya's case, demand estimates and expert interviews suggested that, in the absence of the IPP investments, the missing power would generally be either unserved or provided by diesel-generated emergency power. The implicit cost to Kenya of unserved power has been estimated at around USD 0.84/kilowatt hour (kWh)[3] and the cost of diesel-generated emergency power is around USD 0.31/kWh at current fuel prices. While neither of these figures perfectly captures the counterfactual scenarios, they can be used as reference points against which to estimate savings to the economy, based on the actual cost of IPP power. For example, if the 367 gigawatt hours (GWh)[4] supplied by Olkaria III at USD 0.09/kWh in 2011 had been provided by diesel generators, consumers would have paid an additional USD 89 million in diesel fuel surcharges – which are passed directly to electricity bills. That means that prices in 2011 would have gone up across the board by USD 0.015/kWh. The government would have made USD 11 million more in fuel-tax revenue, ▸▸▸

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Founded in 2001, **Dalberg Global Development Advisors** is a strategic consulting firm that works to raise living standards in developing countries, touching topics from access to finance and energy policy to public health and agricultural development. Our work helps governments, development finance institutions, foundations, international agencies, NGOs, and Fortune 500 companies to make sustainable improvements in the lives of disadvantaged and underserved populations around the world.

[1] *The load factor is defined as the ratio of average energy demand (load) to the maximum demand (peak load) during a period.*
[2] *Interest rate at which the cost and benefits of a project, discounted over its life, are equal. In this case benefits refers to economy-wide cost savings and excludes financial returns for the investor.*
[3] *This cost is cited in Kenya's Least Cost Power Development Plan 2011, and has also been quoted by the World Bank. It is derived from an earlier study estimating the implicit cost of energy not supplied owing to generating capacity deficiencies and/or shortages in basic energy supplies.*
[4] *This is 6% of the total power produced in Kenya that year, but the estimated savings are greater than 6% of total power costs because the alternative is three times the cost per kWh.*

▶▶▶ and KPLC would have paid USD 19 million less to the power producer for non-fuel generation costs, which would eventually have been reflected in base tariffs. The net result is that Olkaria III saved the economy USD 59 million over the emergency power alternative.

The Dalberg team represented projected cost savings like these, plus IPP-related tax revenues, as a stream of annual income to the country, excluding any financial returns to the investors, over the 20-year Power Purchase Agreement (PPA) period, and performed an ERR calculation using the total investment cost of the project. The resulting ERR for Rabai Power, a heavy-fuel plant, was 16% if the alternative was emergency power, not accounting for greater reliability, and 112% against the cost of unserved power. For Olkaria III, a geothermal plant with higher upfront costs but greater annual savings, the results were 27% and 89% respectively. This ERR methodology is not standardised and much of the value of it is in the process of developing the model and observing how returns depend on assumptions such as the dispatch rate or price of oil. But the results also illustrate the significant development returns to investment in a power-constrained setting, and why even higher-cost thermal options appear attractive if the assumption is made that the alternative is unmet demand.

While IPP power may be perceived as more costly than publicly generated power, this is only relevant if there is a choice between the two. In a supply-constrained context such as Kenya, one is not an alternative to the other. KPLC, a separate distribution company, buys power from both the state-owned generator KenGen and IPPs, in both cases through transparent agreements overseen by the Energy Regulatory Commission. Were KPLC able get sufficient supply at a lower price from KenGen, there would no longer be a market for IPPs, but that is unlikely to happen in the foreseeable future and KPLC continues to sign PPAs with both[5].

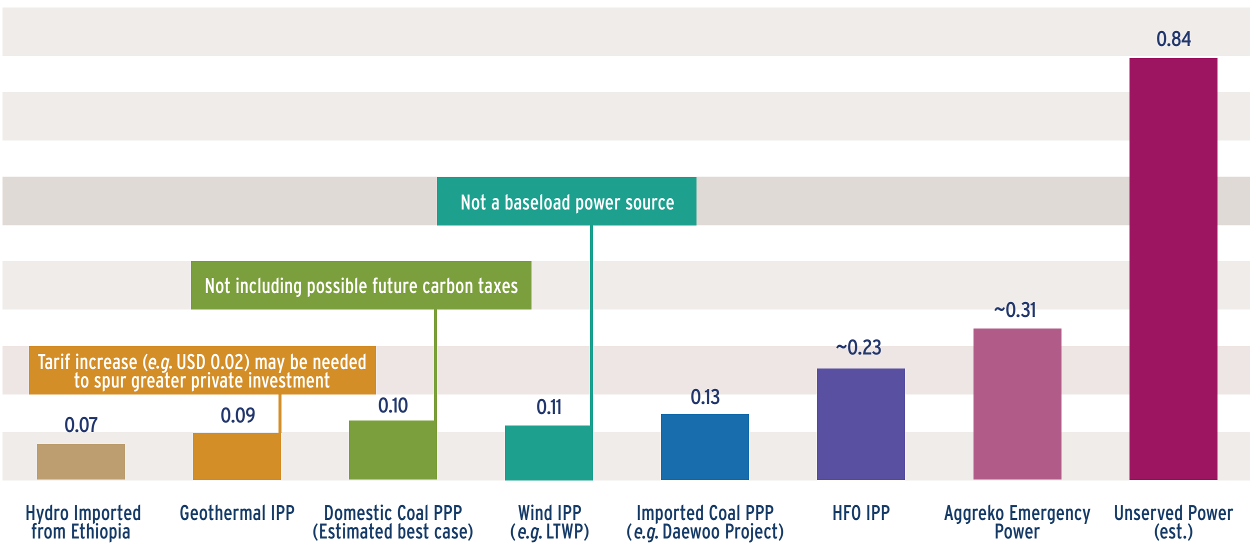
In addition, comprehensively assessing IPP projects in Kenya suggests that they yield a range of positive outcomes at the local and sectorial level, beyond increased power to the grid. For example, a top engineer at KPLC rated the IPPs as systematically the most reliable plants in operation and, given their lower marginal costs, they are often at the top of the dispatch order. IPPs have often been the first to use new technologies in Kenya, including the use of heat capture to power a steam turbine on a thermal plant, well-head generation and a binary isopentane system in geothermal production. Moreover, IPPs have shared technical knowledge with KenGen, which is reflected in KenGen's own recently constructed power plants including Kipevu III. Lastly, because IPPs are typically funded by development finance institutions (DFIs), which have strict international environmental, social and corporate governance (ESG) standards, they often introduce ESG best practice into the local environment – Rabai Power was cited by community activists as a model for other companies to follow.

Limits

Of course, some IPP investments are more beneficial to the country than others. The economic benefit of building a new heavy fuel oil (HFO) plant has diminished since Rabai was

[5] *Note that KenGen is publicly listed with 30% private shareholding, so it must also generate a return for its shareholders.*

FIGURE 2: ESTIMATED PRICES OF SELECTED POWER OPTIONS IN KENYA (USD/KWH)



Source: Dalberg analysis of existing PPAs, project proposals, and expert estimations built in 2009. Rabai Power provides power at a higher cost than Olkaria III's geothermal operations, but the HFO plant met an immediate need to end load shedding on the coast, resulting in high savings against the cost of unserved power. However, now three more HFO plants of similar size will soon come online in Nairobi. It is harder to argue that all three of these are needed to replace unserved power, though they will displace emergency power. The primary advantage of HFO plants is their speed of development, so they are most beneficial where the short-term need is great – in the long term, these plants may be one of the the most costly sources of energy purchased by KPLC.

Investment by IPPs does not guarantee the optimal mix of energy sources. Providers respond to incentives, especially those reflected in feed-in tariffs, which are set by the government. Leaders in the private sector in Kenya have suggested that the current feed-in tariffs are geared too much in favour of investment in thermal power and not enough in geothermal power. Given the superiority of geothermal as an energy source – it is renewable, has near-zero carbon emissions, extremely reliable (unlike hydro), can be used for baseload power (unlike wind), and has low operating costs –, experts are suggesting that the feed-in tariff for geothermal be increased by USD 0.02/kWh or more to accelerate development by IPPs. This would come at a cost to consumers, but if it spurs faster development of geothermal power sources, the increase could easily be compensated for by savings over the cost of thermal power currently produced by both KenGen and IPPs (Figure 2).

"Kenya's experience shows that it is possible to leverage the private sector to achieve national power goals."

Both IPPs and public generators require complementary public investment in transmission infrastructure, and sometimes in pre-development efforts such as geothermal exploration. Kenya has established two government-owned entities for these purposes: KETRACO to build transmission lines and the Geothermal Development Corporation (GDC) to explore steam vents for KenGen and geothermal IPPs. There have, however, been delays in execution of both activities that have hindered IPP investment or reduced its benefits. For example, a new transmission line between Mombasa and Nairobi to transfer power from thermal stations on the coast was to have been completed by 2011 but now looks more likely to be completed in 2014. In the meantime, there is an estimated 100 MW of unused capacity available on the coast from such plants as Kipevu II and III and Rabai, which is still at 50% utilization, pushing down the ERR, even as KPLC continues to pay for emergency power in Nairobi. In geothermal, development of some plants has been delayed for years waiting for GDC – which has suffered from a lack of sufficient funding – to prove the steam. For IPP investment to reach its full potential, Kenya will need to build the capacity of both of these institutions.

Optimizing investment

Nonetheless, Kenya's IPP sector is already one of the most robust in Africa, thanks in part to the commitment of DFIs to funding projects even when other investors would not. Where the public generator is unable to meet demand, the higher returns required by private investors can easily be offset by greater production efficiency, more reliable operations, and the transfer of new knowledge and technologies. Today, as there is considerable investment momentum in the sector, including local providers of capital, not all developers require DFI finance. Some investors are also willing to forgo letters of comfort, given KPLC's perfect record of payment to IPPs and adherence to cost-reflective tariffs. With more than 20 % of power now coming from IPPs, Kenya's experience shows that it is possible to leverage the private sector to achieve national power goals. This experience holds a number of lessons for optimizing future IPP investment. First, the development case for IPP investment should be based on clearly defined economic benefits rather than viewing IPPs as a credible alternative-case scenario. Then, the necessary analysis should be undertaken by the public authorities and validated by the private operator. In Kenya's case, both the Ministry of Energy and KPLC have agreed on the urgent need for new capacity, though the targeted mix of sources should be adjusted as the capacity evolves. Second, it became apparent that separating public generation from distribution helps enable IPP investment by creating an entity whose goal is to obtain reliable electricity at a good price while remaining agnostic about the source, and can establish a credible off-taker relationship with IPPs. Lastly, it is clear that complementary public infrastructure investment, including the development of a grid, can be just as critical as attractive tariffs and a strong policy environment to attracting and utilizing IPP generation. •

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Mining, the key to unlocking Africa's independent power producer markets

The size of power needs in most African countries and the investment required limits the number of projects that can realistically be funded in-country. The private sector could help, particularly where it is strongest – in the extraction of natural resources. Mining companies could be a credible source of bankable off-take contracts and equity funding to make independent power projects a reality.

Jeannot Boussougouth

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There is a positive correlation between infrastructure expenditure and the growth of gross domestic product (GDP). Conversely, inadequate infrastructure is cited as a key constraint to investment and growth. As a result, the provision of quality infrastructure is a necessary in any strategy for economic integration and sustainable development. Various estimates put Africa's infrastructure spending needs to meet the Millennium Development Goals at approximately USD 93 billion per year, of which the electricity sector alone is likely to account for around 44 per cent. Given on-going energy security issues, there is a clear need to increase sub-Saharan Africa's power generation portfolio. The region's total installed capacity is around 70 GW, with South Africa accounting for about 60 per cent of this.

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Although investment is still dominated by the public sector, there is a shift towards the private sector. The role of independent power producers (IPPs) has been fully embraced, for example, in South Africa with its Renewable Energy Independent Power Producer Procurement Programme, in Nigeria's privatisation of Power Holding Company of Nigeria's (PHCN) 11 distribution and 6 generation companies, in Ivory Coast with CIPREL and AZITO, and in Zambia with the Copperbelt Energy Corporation (CEC). This trend is likely to continue in other African countries with an electricity deficit.

The untapped potential of the Democratic Republic of Congo

The Democratic Republic of Congo (DRC), as many other African countries, has huge hydropower potential. The catchment area around the Congo River could theoretically produce an estimated 100 GW, yet less than nine per cent of the DRC's population has access to electricity; just one per cent in rural areas. Only 2.4 GW of its 100 GW potential has been developed and installed ; and only about 1.2 GW is currently available. In the Katanga region, mining companies rely on power from the Inga hydro plants despite an average of 19 interruptions in power each month. In addition, the mines have a power deficit of approximately 900 MW. As a result of the frequent power outages, around 40 per cent of firms in the DRC own and operate thermal generators as an alternative energy resource. This should only be a short-term solution as their continued use translates into higher operating costs at the mines. Several factors suggest that the DRC electricity market could become a significant platform for investment in Africa. Only 48 per cent of the DRC's estimated installed capacity of 2.4 GW is currently operational, and there is a sustained demand for power from mining compa-

« Around 40 per cent of firms in the DRC (...) operate thermal generators as an alternative energy resource. »

nies. The DRC's mining sector is anticipated to expand by an annual average of 13.7 per cent until 2015, by when it is expected to be double its 2010 size, driven by increasing copper production and the development of world-class gold deposits. This is likely to translate into a robust demand for power in a country in which 85 per cent of electricity is consumed by high-voltage users, including mining companies. The country has a significant hydro-power potential. Excluding the Western region, which has 1.9 GW installed and 64 GW of hydro-power potential, the majority of the existing hydro-power plants, generating 467.2 MW, are in the southern part of the country. There is significant hydro-power potential there, too – Katanga, for example, has an estimated 1.6 GW of hydro-power potential, which could be used as feedstock for any potential projects that mining companies want to develop. Established mines and mining companies boast good credit ratings and reliable US dollar cash flows. Their requirement for significant base-load power means that there will be ready long-term off-takers for base loads from independent power projects. This would offer a level of comfort to potential lenders, who typically ask for corporate guarantees from the parent company. Furthermore, an IPP could offer mining companies significant security of supply. A high percentage of metals and mining companies' electricity needs are currently supplied by generator. However, with diesel prices expected to reach around USD 3.82 per gallon (USD 0.84/l) in 2014 (EIA, 2013), given current market conditions, any power project metals and mining companies might decide to develop could be easily economically justifiable. Several factors, however, often affect a country's ability to solve its electricity problems, primarily limited financial flexibility. The potential development of power projects such as the 4.8 GW Inga III would help alleviate this, with South Africa expected to off take approximately 2.5 GW of its future production capacity. Yet the investment requirement is measured in billions of USD – how should the DRC, and, by extension, any other African country, go about realising this type of investment in the next decade or so? Given the size of the DRC's economy, with its GDP being expected to reach an estimated USD 23.9 billion (CGF 21,947 billion) in 2014 (IMF, 2013), it will be challenging to fund major domestic power infrastructure on the government's balance sheet alone. Further, the small domestic banking sector has relatively low liquidity to support this size of investment – the DRC's 20 approved banks currently have an inadequate level of liquidity or tenor for long-term project financing. This is not helped by the fact that the DRC has not been assigned a credit rating by any of the four rating agencies, and as a result the commercial banks' tenor is likely to be short.

« Established (...) mining companies boast good credit ratings and reliable US dollar cash flows. »

Are independent power providers the most appropriate solution?

The refurbishment of old hydro plants and the development of new ones are quite urgent if the current need for power is to be met, in, for example, Katanga. Mining houses need to make a concerted, and if needs be, co-ordinated effort to engage with the local electricity producer, Société nationale d'électricité (SNEL), to solve their problems. Given the high hydro potential and the limited off-take risk in power-purchase agreements (PPAs) signed with strong mining companies, IPPs could be part of the solution. Several commercial considerations need to be taken into account when deciding to develop independent power projects in the DRC or any other African jurisdictions with similar challenges. In the face of perceived political uncertainty, for example, potential lenders will most likely ask for guarantees from either the government or the off-taker's parent company. The relative stability in the south of the DRC and the strength of the mining sector should, however, strengthen investors' and lenders' confidence in Katanga, especially if the World Bank's Partial Risk Guarantee can be used. It is evident that the scale of any potential power project is a function of the demand from the energy-intensive users such as mines in their catchment area. In the case of the DRC, it is possible that the mining houses might need to help fund development costs, perhaps against a reduction in the long-term tariff to make the projects fundable. There are, however other considerations. Given the likelihood that there will be multiple shareholders in most African independent power projects, it is often assumed that a project financing structure is optimal. Assuming a robust contractual structure – gearing levels of 30 per cent equity to 70 per cent debt are usual – many devel- ▸▸▸

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With a market capitalisation of USD 23 billion (31 December 2012) and total assets of USD 183 billion (FY2012), Standard Bank is Africa's largest banking group with a presence in 18 jurisdictions. Within the power and infrastructure sectors, Standard Bank is a leading financial advisor to corporates and institutional investors and is currently advising on energy sector projects encompassing all key technologies, including coal, gas, and nuclear, wind, photo-voltaic, concentrated solar and hydro.

▶▶▶ opers and financiers will need to see the off-taker's PPA risk as being better than that usually on offer in the host country for domestic projects. In addition, it can be anticipated that such a power project would typically be funded by a wide number of lenders, including African and international banks and export credit agencies (ECAs), with the IPP being evaluated on counterparty credit quality and debt-service coverage ratios. It should also be noted that the choice of the engineering procurement construction (EPC) company could have an impact on the lender universe that the IPP would be able to tap into. For example, an EPC company originating from a country with a state-funded, policy-oriented company would not only open up that country's debt market to the IPP but also allow for an ECA-type financing structure with its associated ECA. These agencies typically provide up to 100 per cent political and 85 per cent commercial risk cover. A commercial bank such as Standard Bank, which has the ability to provide equity raising, financial advisory and debt arranging services, could then provide the ECA with the residual commercial risk guarantee. Potential transmission risks are also a likely concern. Although the World Bank recently approved an estimated USD 201.5 million to expand the DRC's transmission capacity, maintenance issues have hampered the effectiveness of the country's transmission network, which has losses of approximately 60 per cent. This situation is similar to that in many other African countries, with transmission issues remaining a constant risk. The fact that many African countries often lack an effective domestic wheeling framework just compounds the issue. Lastly, the non-cost-reflectivity of tariffs is often viewed as a commercial restraint in many African electricity markets. In the DRC, the current average tariff is about USD 0.04 /KWh (Africa in Fact, 2012), well below what is required. Given security of supply issues, it can be anticipated that the development of a power plant for either own use or commercial purposes may result in energy-intensive users paying a higher tariff to any IPP. Given investors typically ask for the tariff to be calculated on a levelised cost of energy (LCOE[1]) basis, an availability payment structure[2] appears to be the most appropriate. We also note that LCOE typically takes into account the weighted average cost of capital (WACC) of the developer and the country's inflation – the DRC's consumer price index is projected to rise by around 8 per cent in 2014 (IMF, 2013) – to determine the minimum price of electricity at which a power project generates enough revenue to pay its costs, including a sufficient return to investors. Some commercial banks such as Standard Bank have the experience and know how to put together and fund large power projects in Africa, including in the DRC. If the mining houses and SNEL were to succeed in Katanga, then the beneficiaries would not just be the mines themselves, but also the broader population, as there would be surplus electricity available to local industry and the general population, which in turn would be a major stimulus to the local economy and the wider development of the DRC itself. Mining companies have the opportunity to play an increasingly enabling role as both potential off-takers and power project sponsors in many African electricity markets. Over the past decade six of the world's ten fastest-growing countries were African, partly the result of the commodities boom. The demand for power is expected to continue to increase in the short to medium term given the need of BRIC countries to access Africa's vast reserves of minerals and other natural resources needed to fuel their own growth. The scale of the power requirements in the majority of African countries and the size of investment required means that the number of power projects that could realistically be funded in-country is limited. Part of the solution is to look to the private sector, and where the private sector is strongest, namely in the development and extraction of natural resources. Based on this, mining companies would be a credible source of both sufficiently bankable off-take contracts and equity funding to make independent power projects a reality, and where better to start than in natural resources-rich regions such as Katanga. Several privately developed power projects are expected to come online within the coming years in such countries as Guinea (Conakry), Mozambique, Ghana, South Africa, and Zambia etc. Their development must be an absolute priority for in-country decision makers; and the speed with which these projects come to fruition needs successful dialogue with Africa's buoyant mining sector. ●

« The non-cost-reflectivity of tariffs is often viewed as a commercial restraint in many African electricity markets.»

[1] The LCOE is an economic assessment of the cost of the energy-generating system including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel and cost of capital.
[2] The availability payments are intended, among other things, to provide the generator with revenue to cover the cost of capital, including a normal rate of return, and the non-variable operating and maintenance costs.

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Developing renewable energies in Africa: a public-private partnership

Likewise mobile phone for telecommunication, is sub-Saharan Africa on the verge to leapfrog conventional energy and move straight to renewable energy (RE)[1] to address requirements for capacity additions? There is genuine potential for RE in Africa. Private producers can play a key role in expanding this sector. For this to happen, governments need to establish a regulatory framework and planning schedules, in co-operation with lenders and donors especially in the handling of the upstream phase of projects.

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Sub-Saharan Africa has an estimated 83 gigawatts (GW) of electricity production capacity, of which 22 GW[2] derived from renewable energy sources. Hydroelectricity, with an installed capacity of 21.6 GW, accounts for an estimated 98% of the total, wind power accounts for 120 megawatts (MW), geothermal for 210 MW and solar energy for around 10 MW (mainly not grid-connected).

While public contracting authorities have mainly focused on the traditional modes of electricity production (especially thermal energy and large-scale hydropower projects) and some power companies are sometimes reluctant to deal with intermittent energy sources, private developers have a key role to play in developing renewable energy (RE) projects in sub-Saharan Africa. These projects can be swiftly set up and are competitive compared with fossil fuels, which make them attractive over the short term.

The potential for RE-based production

The potential for RE in Africa is enormous; the potential for hydroelectricity, for example, is estimated at around 1,844 terawatt hours (TWh), *i.e.* 18 times the level of the continent's hydroelectric production in 2009. Around half of this potential is judged as economically viable (which means that there is a potential additional capacity of 100 GW to 150 GW). Wind energy resources are also very substantial and exploitable even if they are not distributed evenly across the region: 87% of the high-quality resources are located in the coastal zones of the east and south. These are among the best in the world. The solar resource is abundant in Africa and more evenly distributed across the whole of the continent. Supported by appropriate government policies and by steadily decreasing production costs, solar PV could be playing a very important role in Africa's energy supply by the year 2030, with estimates ranging from 15 GW to 62 GW (EREC/Greenpeace, 2010). Finally, geothermal energy is also promising, with a potential estimated between 7 GW and 15 GW (AU-GRP, 2010) – but this resource remains limited mainly to the Rift Valley countries. Many RE projects are currently under development (see box), mainly by independant producers. ▸▸▸

« The potential for RE in Africa is enormous. »

GRÉGOR QUINIOU, ASTRID JARROUSSE AND STÉPHANIE MOUEN

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[1] *The term renewable energy in this paper encompasses hydro, geothermal, wind and solar power.*
[2] *Author estimates, being noted that a portion of above installed capacity is not fully operational and needs refurbishment.*

▶▶ Those are responsible for 98 % of solar power plants (64 % excluding South Africa) and in excess of 90 % of wind farms currently under development. Yet these projects are being developed almost exclusively in countries where independent producers, or producers with an existing RE production capacity, already have an established presence.

The competitiveness of renewables projects

REs are often perceived as over-expensive, particularly due to the high investment costs involved. Yet in fact they are already competitive in standalone systems and in many cases have reached parity with the average cost of electricity generation across the grid as a whole. This is the case for storable energies like hydroelectricity and geothermal energy, but also for intermittent energies like wind and solar power.
The countries of sub-Saharan Africa present a wide variety of scenarios with respect to the cost of their power generation mix. Some have access to relatively inexpensive resources (hydropower capability in Ethiopia, Guinea, Cameroon, DRC ; coal reserves in South Africa) and therefore have a very competitive power generation mix. Here, the economic attractiveness of REs is low, except within an overall strategy of diversifying production – in order to offset the risk of prolonged drought periods, for example, where there is a heavy dependency on hydroelectricity. Other countries have a power generation mix based on fossil fuels, oil in particular (especially the Sahel countries). For these countries, REs represent the least costly alternative. Many countries with gas (*e.g.* Côte d'Ivoire) resources are in an intermediary situation. The perception that renewables are expensive is all the more misguided because fossil fuels benefit from many subsidy mechanisms that mask a much higher real cost. Moreover, the costs of electricity from fossil fuels are rising and subject to high levels of volatility – while REs are tending to cost less overall, while also helping to deliver energy security and independence. REs typically have a very capital-intensive cost structure: development costs (relating in particular to resource evaluation) and investment costs are substantial, whereas operating costs are very low. The point where these projects begin to generate a profit is delayed as a result. Any assessment of their economic attractiveness compared with fossil fuels needs to cover a long time period (15 to 20 years) and take appropriate criteria into account: average discounted production cost per kWh for hydroelectric or geothermal projects; variable avoided costs method[3] for intermittent energies, etc. Given its capital-intensive nature, the cost of finance (debt servicing and capital repayment) is key to the competitiveness of a RE project.

Conditions specific to the emergence of renewable energies

In order to facilitate the emergence of these projects, the countries of sub-Saharan Africa first need to be aware of the potential, competitiveness and benefits of REs. They also need to put effective advance planning in place, incorporating REs within their master plans for the future. Most countries in sub-Saharan Africa have set targets for RE penetration rates in their energy mix 10 or 15 years down the line. This sends out a strong political signal – but it is not enough in itself: these targets need to be translated into production capacity and result in the selection of initial projects and priority sites for development. The planning also needs to take into account the technical constraints connected with integrating intermittent energy sources (wind, solar) into the power grid. For maximum effectiveness it will need to be based on mapping renewable energy sources, in order to determine not just the available potential but also the optimum scale and location of future projects. These plans will enable governments to manage the proliferation of private initiatives more effectively, moving from a supply-

[3] *Comparing the cost per kWh of RE with variable costs (mainly the cost of fuel for thermal energy) of the plants they are replacing*

BOX: RENEWABLE ENERGY PROJECTS IN SUB-SAHARAN AFRICA

Recent studies financed by AFD (Agence Française de Développement), in sub-Saharan Africa (Nodalis, Axenne, 2013; Nodalis, Equilao, 2012; Tractebel Engineering GDF-Suez, 2012) have gathered quantitative data relating to hydroelectric and geothermal power stations, wind farms and solar plants in operation, under construction or under development in 2012.

(MW)	*Hydroelectricity*	*Geothermal*	*Wind*	*Solar*
Installed capacity	*21,500*	*210*	*75.5*	*12*
Plants under construction		*320*	*223*	*43*
Projects under development	*48,000*		*3,790*	*1,876*

driven to a demand-driven approach. At present there is a distinct lack of such integrated strategies in sub-Saharan Africa – with South Africa, perhaps, as the exception. As part of this planning, governments also need to stipulate how projects will be structured (whether the prime contractor will be public or private), set the rules for competitive tendering (calls for tender, calls for project proposals, or the possibility of granting concessions by private agreement) and any mechanisms for providing support to the sector. Several countries in sub-Saharan Africa have developed specific support strategies for REs. The most advanced of these, South Africa, has set up a wide-ranging, robustly structured tender programme that has attracted many potential developers and investors. In 2008, Kenya introduced a subsidised feed-in tariff mechanism – which has proved only moderately successful as the tariff level has been too low to incentivise participation. Other countries like Uganda, Tanzania and Rwanda have followed (for hydroelectric projects) or are considering doing so (Ghana, Botswana). Mechanisms based on subsidised feed-in tariffs or calls for proposals seem attractive for countries where the potential for REs is high. They are more difficult to justify for small-scale markets: setting them up is unwieldy and it is difficult to find the optimum tariff level – one that is both attractive and remains stable over time. In order to facilitate the emergence of RE projects, some countries could put in place a transitional period (of three to five years) during which some projects could be contracted by private agreement (where the law permits), – pending the establishment of specific regulations governing independent producers and/or REs. This approach would be a way of responding to the plethora of initiatives coming from the private sector – while at the same time providing a framework for their implementation.

The importance of upstream support

The private developers present in Africa today do not possess specialist expertise in REs – while the specialists in this field are small-scale developers with limited financial resources and a lack of experience in this sub-region. Setting-up a financing offer dedicated to REs would be a way of enabling them to develop on a larger scale. Yet current initiatives are not explicitly targeted at private projects: they are often larger in scope (focused on climate change) and developers are often unaware of their existence. Support seems particularly crucial during the upstream phase. This is the area where development finance institutions can contribute to the emergence of RE projects – by joining forces with the African funds that are starting to develop in this sector, for example.

Specific conditions relevant to each particular kind of renewable energy also need to be taken into account in promoting their development. The exploration phase of utilising a geothermal resource, for example, is time-, cost- and risk-intensive and is traditionally financed from the developer's own capital. Whatever the qualities of this resource, this is a limiting factor. Various initiatives are seeking to promote the emergence of projects in this sector. Kenya, for example, created the Geothermal Development Company in 2009. This public organisation is charged with taking on the exploration risk – while selling the steam from the wells it has helped to establish to the operators of geothermal power plants (private or public). This enables the latter to focus on operational matters without bearing the burden of the supply risk. Independently, dedicated programmes[4] have been set up for countries which have access to this energy resource in order to establish insurance mechanisms that can partially compensate developers for projects that fail during the exploration phase.

«Support seems particularly crucial during the upstream phase.»

Various avenues are available to provide upstream support for RE projects: dedicated technical support, allocation of public funding, rationalisation of the existing offer and the pooling of facilities offered by funders. Implementing solutions rapidly is critical in order to leverage the potential for REs in sub-Saharan Africa effectively. Successful initial projects will demonstrate the credibility of this model, acting as a catalyst for investment and reducing the need for such support measures further down the line. •

FOCUS

The energy sector is a key strategic priority for the AFD group accounting for an average of EUR 1.5 billion in commitments annually since 2007. Renewable energies and energy efficiency saw the fastest rate of growth over the period 2007–2012, accounting for total commitments in excess of EUR 4.4 billion (i.e. 50% of the total).

[4] The World Bank's African Rift Geothermal Development Program and the Geothermal Risk Mitigation Facility offered by the African Union and KfW development bank.

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Lessons learned from this issue

BY CHARLOTTE DURAND, DEPUTY EDITOR IN CHIEF

Sub-Saharan Africa's power-capacity shortfall limits local peoples' access to basic services and is a major obstacle to the region's economic development. Expanding installed capacity, however, requires substantial funding - funding that cannot be delivered by governments alone. The private sector could play a significant role in meeting this finance gap – and yet its share of electricity production remains marginal. Many countries have not been able – or willing – to embark on the necessary reforms to enable the private sector to contribute significantly in an industry often viewed as strategic and socially sensitive. For its part, private business remains reluctant to invest in environments it sees as lacking transparency and in which the only direct clients are national electricity companies that are often barely solvent, or worse.

Yet Côte d'Ivoire, Kenya and South Africa show that the private sector can contribute not just financially but by providing genuine technical expertise and by helping to diversify the energy mix. The private sector can out-perform the public sector, too. Although its production costs may appear higher, they are not necessarily higher than the costs of the new public-sector power stations. Besides, various studies show that, from an economic perspective, producing expensively is always preferable to not producing at all. The few successful examples in sub-Saharan Africa seem to confirm that while planning in this industry is the public sector's responsibility, production can, at least in part, be managed by the private sector.

A priority for national governments is to restore their national electricity companies to financial health – and a key step in this is to price their electricity properly. These companies' difficulties come, in the main, from the public authorities' reluctance to sell electricity at its real price – primarily for social reasons. Although this approach may seem legitimate, it does not necessarily achieve its aim, as subsidies do not always benefit those most in need. Moreover, subsidies are not viable over the long term: a public operator that does not cover its costs cannot have the resources to expand its production capacity – which means that it has to resort to expensive emergency generators, further aggravating its financial situation.

Public authorities also need to ensure that they possess the human and organisational resources necessary to create a clear, transparent and competitive contractual environment. In particular this means establishing an independent regulator, setting up clear processes for awarding contracts and separating the functions of distribution, transmission and production. These measures will reassure investors and are crucial to ensure a balance between profitability for private operators, and the economic and developmental impact for the state.

Governments also need to elaborate and consistently implement a least-cost development plan. Independent power producers' production costs are reputed to be comparatively high – and this is exacerbated when projects are developed as a matter of urgency, to remedy unanticipated capacity deficits. Yet when independent power projects are integrated within long-term development plans, and are not used as substitutes for less expensive public ones, their impact can be wholly positive. Planning also enables states to invest in long-term options such as renewable-energy sources that have the advantage of improving a country's energy independence but require substantial front-end investments.

There is a long road ahead and increasing awareness of the benefits offered by the private sector will take time. In this context funders have a vital role to play in supporting private-sector projects and helping governments create an environment favourable to the development of independent power producers.

In our next issue

Maximising access to housing

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