MIR

Management Programme in Infrastructure Reform and Regulation

When the power comes
An analysis of IPPs in Africa

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Acronyms

ABB	Asea Brown Boveri
AFD	Agence Francaise de Developpement
AfDB	African Development Bank
AFUDC	Allowance for funds used during construction
AKFED	Aga Khan Fund for Economic Development
ATJL	Artumas Tanzania (Jersey) Limited
BDEAC	Banque de Developpement des Etats de l'Afrique Centrale
BOAD	West African Bank for Development
BOO	Build own operate
BOOT	Build own operate transfer
BOT	Build operate transfer
BPE	Bureau of Public Enterprises (of Nigeria)
CBAO	Banking Company of West Africa
CCGT	Combined cycle gas turbines
CDC	Commonwealth Development Corporation
CEET	Compagnie Energie Electrique du Togo
Cfa	Central African Franc
CIPREL	Compagnie Ivoirienne de Production d' Electricité
CMS	Consumer Michigan Services
COD	Commercial operation date
CTL	Coal to liquids technology & Centrale Thermique de Lome
CUE	Cost of unserved energy
DEG	German Investment & Development Corporation
DFI	Development finance institution
EDF	Electricité de France
EIB	European Investment Bank
EOI	Expression of Interest
EPC	Engineering, procurement, and construction
ERA	Electricity Regulatory Authority (of Uganda)
ERC	Energy Regulatory Commission (of Kenya)
ERB	Electricity Regulatory Board (of Kenya) also Energy Regulation Board (of Zambia)
ESI	Electricity supply industry
EWURA	Energy and Water Utilities Regulator (of Tanzania)
FDI	Foreign direct investment
FMO	Netherlands Development Company
GDC	Geothermal Development Company
GDP	Gross domestic product
GE	General Electric
GW	Gigawatt
HFO	Heavy fuel oil
ICB	International competitive bid
IDA	International Development Association
IFC	International Finance Corporation
IMF	International Monetary Fund

IPP	Independent power project
IPS	Industrial Promotion Services
IPTL	Independent Power Tanzania Limited
IRR	Internal rate of return
JV	Joint venture
KenGen	Kenya Generating Company Limited
km	kilometer
KPLC	Kenya Power and Light Company
kW	kilowatt
kWh	kilowatt hour
LCO	Light cycle oil
MIGA	Multilateral Investment Guarantee Agency
MIR	Management Programme in Infrastructure Reform and Regulation
MMBtu	Million British thermal units
MTPPP	Medium-term Power Purchase Programme (Eskom)
MW	Megawatt
NERSA	National Energy Regulator of South Africa
NNPC	Nigerian National Petroleum Corporation
NPP	New Patriotic Party (of Ghana)
O&M	Operating and maintenance
OCGT	Open cycle gas turbine
ODA	Overseas Development Assistance
OECD	Organization for Economic Cooperation and Development
OPIC	Overseas Private Investment Corporation (of the United States)
PHCN	Power Holding Company of Nigeria
PPA	Power purchase agreement
PPI	Private participation in infrastructure
PRG	Partial risk guarantee
PRI	Political risk insurance
PROPARCO	Promotion et Participation pour la Cooperation economique
PURC	Public Utilities Regulatory Commission (of Ghana)
REFIT	Renewable Energy Feed in Tariff (South Africa)
RfP	Request for Proposal
ROE	Return on equity
RSA	Republic of South Africa
Sida	Swedish International Development Cooperation Agency
SSA	Sub-Saharan Africa
TANESCO	Tanzania Electric Supply Company Limited
TAQA	Abu Dhabi National Energy Company
Tcf	Trillion cubic feet
TDFL	Tanzania Development Finance Company Limited
TPDC	Tanzania Petroleum Development Corporation
UK	United Kingdom
UNECA	United Nations Economic Commission for Africa
UNEP	United Nations Environment Programme

USA	United States of America
USAID	U.S. Agency for International Development
VAT	Value added tax
VIP	VIP Engineering Limited
VRA	Volta River Authority
WAGP	West African Gas Pipeline
YFP	Yinka Folawiyo Power Limited

Executive summary

What prompted the development of independent power projects (IPP) and why are they presently among the most visible elements of power sector reform? Where and why have they taken off and proved successful? And where are the successes less marked?

At the beginning of the 1990s, virtually all major power generation throughout Africa was financed by public coffers, including concessionary loans from development finance institutions. These publicly financed generation assets were considered one of the core elements in state-owned, vertically integrated power systems. In the early 1990s, however, a confluence of factors brought about a significant change. With the main drivers identified as insufficient public funds for new generation and decades of poor performance by state-run utilities, African countries began to adopt a new 'standard' model for their power systems, influenced by pioneering reformers in the US, the UK, Chile and Norway. Urged on by multilateral and bilateral development institutions, which largely withdrew from funding state-owned projects, a number of countries adopted plans to unbundle their power systems and introduce private participation and competition. Independent power projects, namely, privately financed, greenfield generation, supported by non-recourse or limited recourse loans, with long-term power purchase agreements 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. IPPs could be undertaken before sector unbundling. An independent regulator was also not a prerequisite since the PPA laid down a form of regulation by contract.

This report analyses the outcomes of independent power projects (IPP), focusing primarily on Sub-Saharan Africa.[1] Approximately 23 such medium to large-scale projects have taken root to date, concentrated mainly in 11 countries. In total, approximately 4.1GW of IPP capacity has been added. With few exceptions, they represent a small fraction of total generation capacity and have mostly complemented incumbent state-owned utilities. Nevertheless, IPPs have been an important source of new investment in the power sector in a number of African countries; consider for instance Togo, in which Centrale Thermique de Lome (CTL), the country's first IPP raised installed capacity by approximately 40 percent (from 149MW to 249MW); meanwhile, at 250MW, Bujagali is expected to increase Uganda's installed capacity by about 30 percent. The projects covered in this report account for the majority of installed IPP capacity and investment in Sub-Saharan Africa.

The majority of projects have delivered, and their contracts have largely been upheld (namely, CIPREL and Azito in Cote d'Ivoire, Takoradi II in Ghana, Iberafrica, Tsavo,

[1] The decision to focus on Sub-Saharan Africa, rather than expand the analysis to the whole continent of Africa, was taken primarily due to the markedly different investment climate of North African countries, which impacts the size and scale of projects and their associated development. On average, North African IPPs have been more than double the size of their SSA counterparts (at an average of 491 MW vs. 177 MW for SSA).

OrPower4 and Rabai in Kenya, Afam VI in Nigeria, CTL in Togo, and Namanve in Uganda). A number of additional IPPs have reached financial closure and are under construction (Bujagali in Uganda and Itezhi Tezhi in Zambia). Furthermore, in Kenya, financing is presently being arranged for three more IPPs, following an international competitive tender (as well as three directly negotiated projects). Finance is also being sought for the long-awaited addition to Ghana's first IPP, Takoradi II, as well as over a 1000 MW of new power generation, via three different plants, in Zambia. Finally, although not the 1000MW that were initally envisioned, Eskom is harnessing 376 MW via its Medium Term Power Purchase Programme to help avert power shortages in South Africa, with a range of independent producers.

There have, however, been some high profile mishaps, which may have prejudiced the record in SSA. One project has recently concluded its arbitration (AES Barge in Nigeria) and for a second project (IPTL in Tanzania) arbitration is ongoing, however, both projects still form important parts of the power supply in these countries. The costs of another IPP in Tanzania (Songas) escalated as a result of the unplanned, and later disputed, contracting of IPTL. A dispute over escalating investment costs also marked the Okpai project in Nigeria. In addition, in Senegal, GTi Dakar is under financial distress, and the country's second IPP, Kounoune I, is also facing issues due to its inability to procure adequate quality fuel, among other challenges. Changes may be noted in the contracts of one Kenyan plant (OrPower4, which reduced its tariff for the second phase of the plant). One project (Westmont in Kenya) had an initial seven year contract, which was not renewed. The other early IPP in Kenya (IberAfrica) renewed its contract, albeit with much lower capacity charges, and has recently doubled its capacity.

Post contract-changes, projects have largely gone on to make a significant contribution to the country's generation mix (the exceptions being Westmont, which ceased operation, and IPTL, which operated intermittently during and subsequent to its arbitration proceedings). What is different about those projects that have seen no change to date? To what extent may the development and investment outcomes be perceived to be in or out of balance? What are the contributing elements to success in each of these projects?

A suite of country level and project level factors have emerged as playing a critical role in determining project success, chief among them: the manner in which planning, procurement and contracting are coherently linked, the role of development finance institutions along with the development origins of firms and credit enhancements. These and other such factors are spelled out in detail, along with detailed project appendices on each of the 23 IPPs profiled.

In sum, while there is evidence for contract unravelling across the pool of Sub-Saharan African IPPs where an imbalance is perceived between development and investment outcomes, the incidence of such unravelling does not necessarily signal the end of a project's operation. New agreements may be reached that prove sustainable. Meanwhile, efforts must continue to close the initial gap between investors and host country governments' perceptions and treatment of risks (or else examples of further contract unravelling will continue). Finally, the means of closing the gap may not be

only, or mainly, via increasing the sort of new protections, including partial risk guarantees or political risk insurance, and may instead lie in systematic treatment of the numerous contributing elements to success defined by this report.

When the power comes: an Analysis of IPPs in Africa[2]

By Anton Eberhard and Katharine Nawaal Gratwick[3]

This report analyses the outcomes of independent power projects (IPPs) across Sub-Saharan Africa. Approximately 23 such projects[4] have taken root to date, concentrated mainly in 11 countries. A suite of country level and project level factors play a critical role in determining project success, chief among them: the manner in which planning, procurement and contracting are coherently linked, the role of development finance institutions along with the development origins of firms and credit enhancements.

1 Introduction

At the beginning of the 1990s, virtually all major power generation throughout Africa was financed by public coffers, including concessionary loans from development

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[2] This report is an update of previous research published by MIR, initially in Development Policy Review (2008) and subsequently in Energy Policy (2011). For the present update, interviews were conducted with more than a dozen stakeholders, across all 11 countries featured, together with significant secondary source research undertaken.

[3] Anton Eberhard is a Professor at the University of Cape Town's Graduate School of Business (eberhard@gsb.uct.ac.za), Katharine Nawaal Gratwick is a former researcher of MIR and works as an independent consultant (kgratwick@yahoo.com).

[4] This report includes grid-connected projects, greater than 40MW, with a long-term PPA with the utility, which have reached financial close and are under construction, operational, complete or concluded. The authors used 40 MW and above as a size criteria as plants of such magnitude, while small by international standards, are considered sizeable in these markets and have motivated serious domestic and international investment interest. Although smaller plants have also attracted interest, the investment is less substantial (and the associated country and project level factors often less instructive) and therefore the report has been scoped for 40MW and above. The decision to focus on Sub-Saharan Africa, rather than expand the analysis to the whole continent of Africa, was taken primarily due to the markedly different investment climate of North African countries, which impacts the size and scale of projects and their associated development. On average, North African IPPs have been more than double the size of their SSA counterparts (at an average of 491 MW vs. 177 MW for SSA). The authors do not include any detailed discussion of emergency power plants, which may be rented for short periods of up to a couple of years, but, where relevant to IPP developments, some information on these plants is included, primarily in footnotes. Appendix A provides detailed specifications for each project covered in this report; Appendix B provides a list of SSA IPPs (in excess of 40MW) for which finance is presently being arranged; in Appendix C is a list of IPPs equal to or less than 40 MW.

finance institutions (DFIs). These publicly financed generation assets were considered one of the core elements in state-owned, vertically integrated power systems. In the early 1990s, however, a confluence of factors brought about a significant change. With the main drivers identified as insufficient public funds for new generation and decades of poor performance by state-run utilities, African countries began to adopt a new 'standard' model for their power systems, influenced by pioneering reformers in the US, the UK, Chile and Norway.[5] Urged on by multilateral and bilateral development institutions, which largely withdrew from funding state-owned projects, a number of countries adopted plans to unbundle their power systems and introduce private participation and competition. Independent power projects (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 (World Bank, 1993: 45, 51; World Bank and USAID, 1994: 1). IPPs were considered a solution to persistent supply constraints, and could also potentially serve to benchmark state-owned supply and gradually introduce competition (APEC Energy Working Group, 1997). IPPs could be undertaken before sector unbundling. An independent regulator was also not a prerequisite since the PPA laid down a form of regulation by contract.

In 1994, Côte d'Ivoire became one of the first African countries to attract a foreign-owned IPP to sell power to the grid under a long-term contract with the state utility. Ghana, Kenya, Nigeria, Senegal, Tanzania and Uganda, among others, also opened their doors to private sector participation.

Although IPPs were considered part of a larger power sector reform programme, the reforms were not far-reaching. In most cases, state utilities remained vertically integrated and maintained a dominant share of the generation market, with private power invited only on the margin of the sector.[6] Policy frameworks and regulatory regimes, necessary to maintain a competitive environment, were limited. International competitive bids (ICBs) for those IPPs that were developed were often not conducted because of tight timeframes, resulting in limited competition *for* the market and, due to long-term PPAs, no competition *in* the market. These long-term PPAs and often government guarantees and security arrangements, such as escrows and liquidity

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[5] The standard model for power sector reform has been roughly defined as a series of steps that move vertically-integrated utilities towards competition, and generally include the following activities: corporatisation, commercialisation, passage of the requisite legislation, establishment of an independent regulator, introduction of IPPs, restructuring/unbundling, divestiture of generation and distribution assets and introduction of competition Adamantiades et al., 1995: 6-7; Besant-Jones, 2006: 11; Williams and Ghanadan, 2006: 822). Although this model, which was based largely on the early power sector reforms carried out in England and Wales, Chile and Norway, came to represent a standard, it is arguable that not all the steps were relevant to conditions on the ground in most developing countries. See Gratwick and Eberhard (2008b).

[6] Exceptions are Côte d'Ivoire and Tanzania, where IPPs have contributed significantly (more than 50%) to overall electricity production. Togo's first IPP, Centrale Thermique de Lome, added 100MW to the grid and nearly doubled national supply.

facilities, exposed countries to significant exchange-rate risks. Although Africa has seen private participation in greenfield electricity projects continue, private investment has been erratic, with 2007 representing the zenith, due primarily to the financial close of one large project, Bujagali.

Several factors explain the recent trends in investment. Private sector firms were deeply affected by the Asian and subsequent Latin American financial crises in the late 1990s. The Enron collapse and its aftershocks also featured prominently in influencing American and European-based firms to reduce risk exposure in emerging and developing-country markets and refocus on core activities at home. The financial crisis of 2008/9 also had its toll. Furthermore, DFIs began to reconsider their position of restricted infrastructure investment, which had predominated throughout the 1990s.[7] As concessionary funding became available again, many countries opted for a hybrid solution—part public, part private. Kenya represents among the clearest examples as will be highlighted later, with KenGen, the state-owned generator, building alongside IPPs, with support from DFIs.

Despite this revival of concessionary lending, investments are insufficient to address Africa's power needs, with only 25 percent of the population currently with electricity access, and poor supply the rule, not the exception. The cost of meeting Africa's power sector needs is estimated at $40.8 billion a year, equivalent to 6.35 percent of Africa's GDP. Approximately two thirds of the total spending need is capital investment ($26.7 billion a year); the remainder is operations and maintenance (O&M). Current spending aimed at addressing power infrastructure needs adds up to an estimated $11.6 billion. Approximately 80 percent of existing spending is domestically sourced from taxes or user charges. The rest is split among Official Development Assistance (ODA) financing (6 percent of total), non Organisation for Economic Co-operation and Development (OECD) funding (9 percent of total) and private sector investment (4 percent of total). Tackling existing utility inefficiencies, which include system losses, under-pricing, under-collection of revenue and over-staffing would make an additional $8.24 billion available, but a funding gap of $20.93 billion would still remain (Eberhard, 2011).

Closing Africa's power infrastructure funding gap inevitably requires undertaking reforms to reduce or eliminate system inefficiencies. This will help existing resources to go farther and create a more attractive investment climate for external and private finance, which still has the potential to grow. With the original drivers for market reform still present, private sector involvement appears inevitable in the future. This report seeks to evaluate IPPs in Africa by focusing on development and investment outcomes, namely, the extent to which competitively priced power has been provided for the host country, and satisfactory returns on investments and new investment

[7] Two different categories of DFIs should, however, be distinguished, namely those which lend on commercial terms and largely to private companies (e.g. FMO, PROPARCO, DEG and IFC) and the multilateral development banks (e.g. the World Bank and the African Development Bank) which lend on concessionary terms and primarily to public sector projects. It is the latter that re-focused on infrastructure (Rudo, per com, 2010a).

opportunities have been achieved. Case studies of 11 Sub-Saharan African countries (Cameroon, Côte d'Ivoire, Ghana, Kenya, Nigeria, Senegal, South Africa, Tanzania, Togo, Uganda and Zambia) which have some of the most extensive experience with IPPs, provide the empirical data for this analysis. At its core is a discussion of how the balancing of development and investment outcomes actually helps improve the sustainability of projects for public and private stakeholders alike. Contributing elements to success are also identified as the building blocks for more sustainable investments.

2 IPPs in Africa: an overview

Approximately 23 grid-connected IPPs, each in excess of 40 MW, holding long-term PPAs with the largely state-run utilities, have been developed in Sub-Saharan Africa to date. In total, approximately 4.1GW of IPP capacity has been added. With few exceptions, they represent a small fraction of total generation capacity and have mostly complemented incumbent state-owned utilities.

Nevertheless, IPPs have been an important source of new investment in the power sector in a number of African countries; consider for instance Togo, in which Centrale Thermique de Lome (CTL), the country's first IPP raised installed capacity by approximately 40 percent (from 149MW to 249MW); meanwhile, at 250MW, Bujagali is expected to increase Uganda's installed capacity by about 30 percent. The projects covered in this report account for the majority of installed IPP capacity and investment in Sub-Saharan Africa.[8]

Table 1: African IPP sample (>40MW), general project specifications[9]

[8] Although Mauritius has 4 IPPs (which, at approximately 200 MW combined, account for about 37% of installed capacity), the country has not been included in this sample. The IPPs, which are all cogeneration plants, provide power and steam to the country's sugar mills throughout the crop season, reducing their contribution to the state-owned utility by about 30%. During this time, the shortfall in production is made up by 7 Continuous Power Producers (CPPs), privately owned by the sugar mills. With installed capacity of 40 MW, roughly equal to the IPP shortfall, the CPPs also have long-term take or pay contracts with the state (Bergesen, 2007; World Bank, 2007a). See Appendices C and D for further detail.

Country/ Project	Size MW	Fuel/cycle	Contract type	Contract Yrs	COD
Cameroon					
Dibamba	88	HFO/peaking plant	BOT	20	2009
Kribi	216	Natgas/open cycle	BOT	20	2012
Cote d'Ivoire					
CIPREL	210	Natgas/open cycle	BOOT	19	1995
Azito	288	Natgas/open cycle	BOOT	24	2000
Ghana[10]					
Takoradi II	220	Light crude /single cycle	BOOT	25	2000
Sunon Asogli	200	Combustion engine	BOO	20	2010
Kenya					
Westmont	46	Kerosene/gas condensate/gas, turbine	BOO	7	1997
Iberafrica	108.5	HFO/medium speed diesel engine	BOO	7, 15, 25	1997, 2000, 2009
OrPower4	48	Geothermal	BOO	20	2000, 2009
Tsavo	74	HFO/medium speed diesel engine	BOO	20	2001
Rabai	90	HFO	BOOT	20	2009
Nigeria					
AES Barge	270	Natgas/open cycle, (barge-mounted)	BOO	13	2001
Okpai	450	Natgas/combined cycle	BOO	20	2005
Afam VI	630	Natgas/combined cycle	BOO	20	2008
Senegal					
GTi Dakar	52	Diesel/nafta	BOOT	15	1999
Kounoune I	68	HFO	BOO	15	2008
South Africa					

[9] As indicated in footnote 4, projects covered here are greater than 40MW, which have reached financial close and are under construction, operational, complete or concluded

[10] Not included in this tally of IPPs is the Bui Hydro project of Ghana. Sino Hydro, of China, is the designated contractor, and the project "is expected to cost US$622 million and be funded by a US$263.5 million concessional loan from the government of China, a US$298.5 million buyer's credit facility from the China EXIM Bank, and US$60 million from the Ghanaian government. A special purpose vehicle, the Bui Power Authority, has been established to manage the construction and operation of the project," (Kapika & Eberhard, 2012). It is understood, however, by the authors at the time of writing that ownership of this project rests with the Ghanaian government.

Sasol	240	OCGT	MTPPP	5	2010
Tanzania					
IPTL	100	HFO/medium speed diesel engine	BOO	20	1998
Songas	189	Natgas/open cycle	BOO	20	2004
Togo					
Centrale Thermique de Lome	100	Triple fuel (natgas/HFO/diesel)	BOOT	25	2010
Uganda					
Namanve	50	HFO	BOOT	6	2008
Bujagali[11]	250	Hydro	BOT	30	2011
Zambia					
Itezhi Tezhi	120	Hydro	BOOT	25	2014

3 Understanding the experience of IPP investments in Africa

What has been the experience of IPPs in Sub Saharan Africa? The majority of projects have delivered, and their contracts have largely been upheld (namely, CIPREL and Azito in Cote d'Ivoire, Takoradi II in Ghana, Iberafrica, Tsavo, OrPower4 and Rabai in Kenya, Afam VI in Nigeria, CTL in Togo, and Namanve in Uganda). A number of additional IPPs have reached financial closure and are under construction (Bujagali in Uganda and Itezhi Tezhi in Zambia).[12] Furthermore, in Kenya, financing is presently being arranged for three more IPPs, following an international competitive tender (as well as three directly negotiated projects). [13] Finance is also being sought for the long-awaited addition to Ghana's first IPP, Takoradi II, as well as over a 1000 MW of new power generation, via three different plants, in Zambia. Finally, although not the 1000MW that were initally envisioned, Eskom is harnessing 376 MW via its Medium

[11] The first phase of Bujagali's conceptualization spanning the mid 1990s until 2003 and involving AES is not covered in this report. It should be noted that the project did not reach financial close during this time. Authors report only on the project from its second phase, starting in 2005.

[12] Another project should be noted in this context: Aba Integrated (140 MW) in Nigeria is presently under construction, but financial close has not been reached. The project, an 'enclave' IPP, is being developed by a 100% Nigerian-owned firm, Geometric Power Ltd, following traditional construction financing (not non-recourse, project financing); ownership will extend to the off-taker, when the project is complete, and the project is not connected to the national grid.

[13] Details for all six Kenya projects, totaling more than 660MW, may be found in Appendix B, along with subsequent in-text references to new power additions.

Term Power Purchase Programme (MTPPP) to help avert power shortages in South Africa, with a range of independent producers.[14]

There have, however, been some high profile mishaps which may have prejudiced the record in SSA. One project has recently concluded its arbiration (AES Barge in Nigeria) and for a second project (IPTL in Tanzania) arbitration is ongoing, however, both projects still form important parts of the power supply in these countries. The costs of another IPP in Tanzania (Songas) escalated as a result of the unplanned, and later disputed, contracting of IPTL; its capacity charges were later reduced after government agreed to buy down the accumulated Allowance for Funds Used During Construction (AFUDC) costs. A dispute over escalating investment costs also marked the Okpai project in Nigeria. In addition, in Senegal, GTi Dakar is under financial distress, and the country's second IPP, Kounoune I, is also facing issues due to its inability to procure adequate quality fuel, among other challenges. Changes may be noted in the contracts of one Kenyan plant (OrPower4, which reduced its tariff for the second phase of the plant). One project (Westmont in Kenya) had an initial seven year contract, which was not renewed. The other early IPP in Kenya (IberAfrica) renewed its contract, albeit with much lower capacity charges, and has recently doubled its capacity.

Post contract-changes, projects have largely gone on to make a significant contribution to the country's generation mix (the exceptions being Westmont, which ceased operation, and IPTL, which operated intermittently during and subsequent to its arbitration proceedings). Although termed 'emergency power', another high profile failure was the non-transparent procurement of the Richmond/Dowans (bought by and now known as the 'Symbion plant') in Tanzania which, initially after the levelling of corruption charges, was not allowed to operate.[15] Furthermore, there has been evidence of projects stalling, as seen in the case of Takoradi II's second phase, which has taken more than 10 years to commence its second phase of development. What is different about those projects that have seen no change to date? To what extent may the development and investment outcomes be perceived to be in or out of balance? What are the contributing elements to success in each of these projects?

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[14] The 1000MW of envisioned power, referenced above, refers to the two OCGT peaker plants which were initially expected online by the end of 2009. An ICB was conducted, but the preferred bidder (AES) ultimately pulled out. Meanwhile negotiations are ongoing with Suez to develop these plants, which may now be redundant, and therefore development may ultimately be stopped by the regulator (NERSA). See appendices A and C for additional information about South Africa's MTPPP plants (varying in size from 240MW to 2.6MW, including cogeneration plants). Finally, it is important to note the development of South Africa's renewable energy IPPs (an estimated 3750 MW), for which preferred bidders may be announced by the end of 2011.

[15] The Symbion plant (previously known as/owned by Richmond/Dowans) has since been brought back into service at full throttle (117MW), and its present owner, American-based, Symbion Power, has also been contracted to install additional capacity in Tanzania (upwards of 250MW). Although initially conceived of as 'emergency power' (most of the units are trailer-mounted and may be easily removed), contracts for the Symbion plant have been extended, with no clear sense of how and when the plant will be taken out of service.

3.1 Building up contributing elements to success, at country level

Favourable investment climate

With the exception to South Africa, which has only recently began to develop full-fledged IPPs, there are no investment grade ratings for any of the countries covered in the sample. Of the seven countries that have received a speculative rating (Cameroon, Ghana, Kenya, Nigeria, Uganda, Senegal, Zambia), four of these ratings (Kenya, Nigeria, Senegal and Uganda) were received after the first IPP deals were signed, with Kenya's investment climate defined, at the time, by its aid embargo in the mid-1990s.[16] Tanzania is also worth mentioning in this context. Throughout the 1990s, all export credit agencies were off-cover in Tanzania; no foreign commercial banks were willing to lend, as there was no clean track record of commercial loan repayment. Consequently, the possibility for a traditional project-financed IPP deal in this climate was limited. Nevertheless, as we have already noted, IPP projects were developed in challenging investment climates in a number of Sub-Saharan countries.

Contrast this scenario with IPP developments in North Africa, where there are at least three notable IPP success stories (in Egypt, Morocco and Tunisia) and in which countries have either had an investment grade rating or one notch below (Gratwick and Eberhard, 2008a). Credit enhancements and security arrangements have differed broadly between North and Sub-Saharan Africa but, interestingly, incentives offered to investors in IPPs were relatively similar across the pool of projects, with some variety with regard to tax breaks. For instance, nearly all projects appear to have benefited from both customs and VAT exemptions during construction, as well as full repatriation of profits. Currency conversion was also provided for virtually all of the projects. In terms of tax holidays, in East Africa, Tanzania provided a tax holiday of five years, but Kenya's tax holidays extended only until plant commissioning. Although one would expect the investment incentives to increase with the perceived risk (with increased incentives offered in SSA), such a pattern is not apparent.

How did the investment climate impact on project development? Quite simply, with demand for IPPs outweighing supply, those countries with a better investment profile attracted more investors and ultimately were able to cement deals on terms more favourable to the host country. The main take-away then is: since all countries and entities compete for capital, a risk-reward balance needs to be offered that will attract investors/lenders. That 'balance' starts with a stable and predictable investment environment, which has been the bottom line in project finance in developing countries because it is fundamental to being able to attract financing (Rudo, per com, 2010a).

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[16] Zambia received its rating of B+ from Fitch in March 2011. Financial closure (for the Itezhi Tezhi hydro power station) was reached subsequent to this date.

While not the only factor in influencing outcomes, the investment climate goes a long way in setting the stage for negotiations and more balanced contract terms and helps explain the initial imbalance in some of the SSA cases.

New policy frameworks and regulation

Although all 11 countries in the sample have introduced legislation to allow for private generation, few have actually formulated and then realised a clear and coherent policy framework for procuring IPPs. As noted by one stakeholder, but generally true for the sample of countries, "There is no policy that articulates the allocation of new build opportunities between [the utility] and the private sector." In one particular instance, which again is not altogether uncommon, certain key personnel at the utility, the ultimate buyer of generation, presently and for the forseeable future, were not aware of the range of potential IPPs. This suggests that the planning process is not robust nor is it linked with the initiation of procurement. Another stakeholder, involved in Nigerian power sector reforms, spoke of the underlying chaos in past IPP developments (BPE consultant per com 2011).

Thus, while there is abundant evidence of tentative experimentation with private power, it does not always lead to a sustained opening of the market for private investment. As one industry stakeholder indicated in Togo, "the branch of production is 'open' to IPPs," but in that country there is only one IPP (Autorité de Réglementation du Secteur de l'Electricité per com, 2011). Furthermore, long-term PPAs have the potential to constrain wholesale competition in the future, although means to transition to wholesale competition with IPPs have also been identified (Woolf and Halpern, 2001). In addition, state-owned utilities are rarely exposed to market costs of capital, and direct comparisons of their costs with IPPs are often difficult to discern.

Nowhere in Africa is the standard reform model for power sector reform being adopted fully, namely, unbundling of generation, transmission and distribution, and introducing competition and private sector participation at both the generation and distribution level (UNEP and UNECA, 2006: 67; Malgas et al., 2007; Gratwick and Eberhard, 2008b). Most incumbent national utilities are state owned and in a dominant position. However, elements of the reform model have been adopted. Noteworthy in this context is Nigeria, which is undertaking, for a second time, to divest ownership in nearly all federal-owned plants, along with divestiture of 11 federally-owned distribution companies. Although plans for the reform have been on the books since 2005, it has taken an erosion of the ESI (together with a change in leadership) to galvanize reform, which also specifies an independent, albeit publicly-owned, transmission company.

Meanwhile, Kenya is among the most advanced in terms of its actual implementation of reform; it has long since unbundled generation from its national transmission and distribution utility—reforms dating to 1997—and a proportion of the shares of the two Kenyan utilities, KPLC and KenGen, are listed on the Nairobi stock exchange. Uganda unbundled its national utility into separate generation, transmission and distribution companies and entered into long term private concessions in generation (Eskom) and

distribution (Umeme – Globeleq). More recently, Ghana has also unbundled generation, transmission and distribution. In Cameroon and Cote d'Ivoire, there are long-term concessions for the integrated utilities, with the latter dating from 1990 and expected to last until 2020. In South Africa, Tanzania and Zambia, full adoption of the standard model was tabled, but then ultimately rejected, including after a 4-year management contract of TANESCO, in Tanzania. Togo experienced a five year concession, for its distribution, only to revert back to public hands in 2006. Finally, in Senegal, there was an attempt to privatize Senelec in 1999 through a concession with Hydro-Québec and Elyo, which was annulled by the president in 2000.[17]

In each of these countries, the private sector has also invested in IPPs, as previously discussed. Thus, there has been competition *for* the market, but not ongoing competition *in* the market in terms of customer choice. In effect, what have emerged across Africa (and in many other developing regions) are hybrid power markets. The incumbent state-owned utility continues to play a key role in the sector but because of inefficiencies and inadequate investment resources, IPPs are gradually being introduced. As we shall see later, these hybrid power markets give rise to new challenges which need explicit attention if private investment is to be accelerated.

All these countries have, however, established independent regulators, which are intended to address some of the 'regulatory risk' that IPPs face, as highlighted below. Further details of mitigation, including political risk insurance and partial risk guarantees, are also discussed in Section 3.2 under 'project-level factors'.

[17] Togo's resumption to public hands was a result of the concessionaire terminating the contract due to unresolved disputes (Togo, per com, 2011b); in the case of Senegal, there is evidence pointing to the fact that the newly elected government of Abdoulaye Wadewas dissatisfied with progress made, particularly with regard to ending power cuts (Oxford Business Group, 2008: 90).

Table 2: Regulatory Risk

Risk	Mitigation
• Arbitrary changes to rules, and/or addition of new rules • Misapplication of rules • Too much regulatory discretion in price reviews • Additional cost risks (associated with performance and environmental standards, accounting rules, taxation)	• Change of law exemption • Clarity of regulatory framework and approval processes • Regulatory discretion limited • Regulatory capacity built • Political risk insurance • Partial risk guarantee • Appeal process and dispute settlement facilities

Based on Ferreira, 2004

In Kenya, the regulator, together with the adoption of ICB practices, has helped to reduce PPA charges radically (between the first set of IPPs negotiated and the second). A similar trend may be seen in Senegal, where the first IPP (GTi Dakar) was not overseen by the independent regulatory body and the second (Kounoune I) was, together with a more experienced Senelec, with benefits associated with the latter project (CRSE, per com, 2010; IFC, per com, 2010b). Kenya's Energy Regulatory Commission (ERC) has also been instrumental in helping to set tariffs and manage the overall interface between private and public sectors.[18] In Uganda, sponsors have noted the benefits of having the regulator involved from project inception, namely helping to increase overall transparency, especially in the case of Bujagali. Staff from the Ugandan Electricity Regulatory Authority (ERA) affirm that "ERA's presence has helped to focus minds on the requirements for setting up power supply projects so that investors coming in are clear of what is expected of them from the beginning hence align their bids to these requirements. As a result, we have increasing numbers of investors applying to set up IPP projects" (ERA, per com, 2010). In Cameroon, an independent regulator came into existence in 1998, before the 20-year concession for the vertically integrated utility was awarded. Subsequently, with regulatory oversight, both IPPs have been developed by the same company as the concessionaire (namely AES), albeit with the first IPP directly negotiated and the second following an ICB. Arguably AES has an advantage in the sector, given its experience, however, the lack of competition, despite independent regulation, is noteworthy.[19]

[18] "Perceived independence of the regulator is important. In Kenya, the ERC levy of 3 (Kenyan) cents per kWh is seen as providing independence. The experience of ERC for 13 years is also a big plus," (Mwangi per com, 2011).

[19] Operational since 1996, Zambia's Energy Regulatory Board (ERB) has preceded all IPP development (with the first large scale IPP, Itezhi Tezhi, only due online in 2014). However, the mere fact of its existence, as noted in the case of Cameroon, is not necessarily indicative of development. Furthermore, "several industry stakeholders have stated that they do not see the ERB as independent but rather as beholden to government," (Kapika & Eberhard, 2012). In the

The National Electricity Regulator was established in South Africa in 1994/5 but, as previously noted, reforms have lagged in that country, including the introduction of IPPs. Recently government has taken the lead in running procurement processes for IPPs, initially for two open-cycle gas turbines totalling just over 1000MW (which may now finally be awarded to the second bidder, Suez, after the preferred bidder, AES, withdrew). In addition, in 2011, a large multi-bid procurement process was launched for 3750 MW of wind, solar and other renewable energy technologies. Government has expressed concern that the regulator (now NERSA) may create some uncertainty around the licensing of these IPPs and the approval of PPAs. The regulator held public hearings where some submissions argued that the peaker plants were not required and that there were other more efficient demand-side options. With regard to the procurement of renewable energies, the regulator (with little consultation with government) announced a renewable energy feed in tariff (REFIT) in 2009 and a subsequent revision in 2011. Government subsequently declared that the REFIT was potentially illegal and launched its own competitive procurement programme. Government is now considering amendments to the Electricity Regulation Act which would restrict the decision-making discretion of the regulator on licences and PPA approvals if IPPs are procured through a competitive process.

In Côte d'Ivoire, Ghana, Nigeria and Tanzania, regulatory agencies have come into force only after IPPs have been negotiated, and there has been little impact as of yet in terms of new investment. What has emerged as a general trend is that the mere presence of a regulator is not in and of itself a defining factor in attracting IPPs. An independent regulator may have positive, negative or no impact on outcomes. If, however, regulatory governance is transparent, fair and accountable, and if regulatory decisions are credible and predictable, there is greater potential for positive outcomes for host country and investor alike. Evidence also points to the fact that effective regulatory oversight may lead to a reduction in the stated capital costs of projects for selectively bid projects, as well as improved efficiencies (Phadke, 2007: 10,25; Eberhard, 2011).[20]

A final policy and practice is worth noting in this context: in three of the 11 sample countries (Cameroon, Nigeria and Tanzania) efforts have been made to exploit stranded gas as part of the IPP programme.[21] In Cameroon, the Kribi IPP is linked to

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case of Togo, here again, an independent regulator predated the IPP, however, with just one IPP, CTL, it is hard to gauge impact.

[20] Furthermore, alternatives to strictly independent regulation are increasingly being considered (viz. regulatory contracts, the outsourcing of regulatory functions, expert panels and regional regulators) which may provide a better match to a country's regulatory commitment and institutional and human resource capacity (Eberhard, 2007: 14).

[21] Domestic gas reserves were used for IPPs in Côte d'Ivoire; however, unlike for the other countries mentioned above, this did not represent the establishment of a new gas infrastructure. An attempt was also made to exploit stranded gas reserves in Ghana's Osagyefo Barge project, which, however, has been led by the state, with, as of yet, no private participation, and no power produced.

development of the Sanaga Sud gas project; Kribi will initially be its primary off-taker, and in turn will be ensured security of fuel supply. In Nigeria, a reduction in gas flaring was central to the push for gas-fired power.[22] In the late 1990s, at the start of Nigeria's power sector reforms, the country contributed to more than 15% of global gas flaring (or approximately 1.6 trillion cubic feet (Tcf) per year). The commercial loss (estimated at US$2.5 billion annually) together with the environmental damage initially motivated the country to target 2008 as the year to end all flaring, a date that has subsequently been moved out to 2011, and more recently to December 2012 (Kupolokun 2002;Yusuf 2011). As part of this initiative, international oil companies were enlisted in harnessing gas for power, and the Okpai and Afam VI projects were subsequently born. In Tanzania, the IPP programme commercialised previously stranded (although not flared) gas via Songas and Mtwara (a small private concession in the south of the country). Both of the latter countries have seen a distinct set of challenges[23]; however, in general this larger policy has insulated projects from intense public scrutiny, with project sponsors and policy-makers alike able to point to the benefits of the commercialised gas and the reduction in fuel imports. With Kribi due online 2012, the story is un-concluded, however, similar benefits are anticipated.

Behind many of these policies sit the development finance institutions, notably the World Bank, which has had a hand in nearly all power sector reform programmes in Africa. These institutions were particularly instrumental in advancing private sector participation in generation. However, as many of those same institutions began reconsidering publicly-funded infrastructure investments at the end of the decade, countries have often followed with policies that reflect this movement – from state to market and back again, albeit with some changes to accommodate what has emerged as a more hybrid market, as will be discussed in greater detail below.

Linking planning, procurement and contracting

Intricately connected to sound policy frameworks are coherent power sector plans, which are linked to procurement and contracting. Ideally, the latter (planning, procurement and contracting) follow from the former (sound policy frameworks) and include 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; and clarifying how new generation production will be split between the private and public sectors as well as the requisite bidding and procurement processes for new builds. Among the most important aspects of coherent power sector planning is

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[22] Although gas flaring reduction was a central piece of the reform agenda, more recent reports have downplayed its importance. "We got into that power plant purely as a way of identifying with the aspiration of the government of Nigeria to improve the power situation in the country…normally power business is not our business, however as a corporate citizen here, we felt that power is something that this country needs and we rose up to the challenge," (Mutui Sunmonu, MD and Chairman, Shell PDC, 2011, as excepted from 'From Darkness to Light').

[23] In Nigeria stakeholders have seen costs escalate which in turn has caused the utility to withhold payments. In Tanzania, costs have also escalated, but for reasons unrelated to the project itself.

vesting planning and procurement in one empowered agency to ensure that implementation takes place with minimal mishaps (Malgas and Eberhard, 2011).

The adverse consequences of not linking planning, procurement and contracting: That is the ideal, but the reality often takes on a different shape. As one stakeholder at Ghana's Public Utilities Regulatory Commission (PURC) notes about the recent past, "A crisis arises, and everybody panics; anybody who comes in [to propose generation] is listened to," (PURC, per com, 2010). The sample evaluated here has had several noteworthy planning mishaps, which subsequently impact procurement and contracting. In evidence are examples of demand and supply not being accurately forecast due partly to extended droughts, which in turn necessitated fast-tracking IPPs, i.e. plants were sped through to meet immediate power shortages. The first two plants in Kenya (Westmont and Iberafrica), the first plant in Nigeria (AES Barge) and Takoradi II in Ghana were negotiated amidst drought conditions, along with the first plant, Dibamba, in Cameroon, with the 'emergency' nature of the situation cited among the reasons why an ICB was not pursued in this case (AES per com, 2011). Generally, the speed was at a cost. Although both Westmont and Iberafrica came on line within eleven months, they were later the source of scrutiny and investigation (due to un-transparent bidding practices and what were perceived as unnecessarily expensive charges). Furthermore, Westmont did not secure a second PPA, due to disagreement over a tariff, with public stakeholders unwilling to make similar concessions a second time. In the case of Nigeria, although fast-tracked, the AES Barge took nearly two years to come on line due to a renegotiation of the PPA. In Ghana, it has taken more than ten years to reach agreement about the second phase of the project.

An inability to estimate demand and supply accurately as well as set a clear reliability standard and ensure projects are carried out in a timely fashion has also necessitated several cases of emergency power where units have been leased for one to two years with the purpose of plugging a short-term crisis. Although in constant flux, in 2009, approximately 750 MW of emergency power was in operation in SSA (Foster and Briceno-Garmendia, 2010). In all three of the East African countries in this sample as well as Ghana, the governments have ordered units to address drought and system collapse. Kenya harnessed 100 MW of emergency power in 1999-2001 and again in 2006 (supplied by Aggreko, Cummins and Deutz in the first instance and Aggreko alone in the second). In 2007, Aggreko's contract was extended for an additional two years, and in 2009 Aggreko was selected to provide a further 140 MW for a total of 290MW of emergency power. By mid-2010, however, the requirement was reduced (to only 60 MW) with a plan to retire all such emergency power by November. Re-emergence of drought in the latter part of 2010 led to a turn-around in such a plan, with new installations (40MW) at Muhoroni, which may be followed by an additional 80 MW (within the next 18 months), as well as 50 MW additional of emergency power (for a total of 110) at Embakasi--all to help avert power rationing.

Emergency power has been turned to repeatedly in Tanzania and Uganda also. In Ghana, emergency power was instrumental in reducing the impact of the 1998 drought, but with drought conditions reversing, the state failed to honour its contracts with SIIF Accra, which was cancelled and which remained an unresolved dispute between Ghana

and EdF, with the latter finally liquidating the asset in 2010 (EdF, 2010).[24] Costs for this emergency power, at approximately 30-40 US cents/kWh, are high; however, they are still less than the cost of no power (IFC, per com, 2005) (Oxford Policy Management, 2011: 3). Tanzania has estimated that it has saved around US$1.00 for every kWh of outage averted (or about five to ten times the ordinary cost of generating electricity).[25] In terms of assessing the overall impact, "the estimates of the value of lost load or unserved energy, power outages in the countries in Sub-Saharan Africa constitute an average of 2.1 percent of GDP," (Eberhard, 2011:7).[26]

Case study: planning, procurement and contracting in Tanzania: In Tanzania, the speeding through of one plant (IPTL) has resulted in perhaps the highest-profile IPP story on the continent to date. In this project, critical planning elements are missing, namely, a clear reliability standard, an accurate demand and supply forecast, a detailed plan for privately powered and publicly powered generation, and most importantly timely initiation of procurement and effective conclusion of contracts.

The Songo Songo gas-to-electricity project was in the Power System Master Plan, initially slated to come online within six months. However, the project was slow to materialise, given its technical and financial complexity. With deadlines passing and power cuts persisting, it is alleged that other ministries, affected by the power cuts, started second guessing whether the Tanzania Electric Supply Company Limited (TANESCO), the state utility, and the Ministry of Energy and Minerals, following the World Bank procurement procedures and relying on concessionary loans, would be able to deliver the project on time to address the shortages. As noted previously, the cost of unserved electricity to the economy was high and therefore Tanzania paid dearly for no power. Thus, the backdrop to the IPTL agreement appears to have been a failure to deliver on the Master Plan and hefty associated costs for many Tanzanians facing loss of services, TANESCO facing loss of revenue, and the Tanzanian economy facing loss of productivity, together with a clear interest in collaborating with Malaysian investors in the context of South-South partnerships.

The impact of this planning mishap was multi-fold: IPTL, which was negotiated quickly, behind closed doors, announced its total investment costs as US$150 m. (US$163 m. including fuel conversion), which the government and the World Bank

[24] More recently, the American-based, Genser Power has constructed 3 units in Ghana for dedicated commercial/industrial users for whom reliability has been a serious concern, namely 5MW, providing electricity and steam, 30MW providing back-up generation and 25MW providing full-time generation. Contracts range between 5-10 years, and therefore it is neither typical back-up generation nor emergency power per se (Genser per com, 2011).

[25] In terms of international norms, however, it should be noted that Tanzania's cost of unserved energy (CUE) is low. South Africa's CUE is approximately US$10/kWh, which is in line with the CUE in many industrialised countries (Global Energy Decisions, 2007).

[26] Finally, it should be noted, that there is also evidence of engaging emergency power around the time of elections (where there is often heightened political risk).

would later argue was inflated by 40 percent. This argument would in turn lead to a lengthy arbitration process spanning three years. During the time that IPTL was being disputed, the Songo Songo gas-to-electricity project would be put on hold, mainly through pressure from the World Bank, its largest donor, due to alleged corruption in the sector. Although the arbitration would ultimately lead to IPTL's investment costs being reduced to US$127 m., the cost was still above and beyond the price that the government sought to pay. Furthermore, due to the delays, Songo Songo accumulated US$100 m. in interest during construction (AFUDC) on owner's equity, i.e. which the sponsor was owed by TANESCO. Additional costs to the state include the emergency power that was required due to both IPPs being unavailable until 2002 and 2004, respectively, as well as inflated costs associated with the Symbion power plant (previously known as Richmond/Dowans plant), procured via a negotiated deal in 2006 for a period of two years, and which, like IPTL, has subsequently been the subject of intense controversy and legal disputes.[27]

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. The solution appears to lie in: taking steps to improve the investment climate, drawing up and implementing clear policy frameworks, (namely, spelling out where and how private power fits into a single-buyer model), building contingencies into the planning process, vesting planning in one agency, and conducting timely and open bidding.

The role of ICBs in planning, procurement and contracting: Considerable attention has been paid to the importance of international competitive over selective bidding practices. Two studies have evaluated the relationship, demonstrating that, while there is evidence for ICBs leading to up to a 60 percent reduction in the stated capital cost of plants, there is also evidence for selective bidding proving effective in certain instances, provided there is regulatory scrutiny (Deloitte Touche Tohmatsu Emerging Markets Ltd. and Advanced Engineering Associates International, 2003; Phadke, 2007). The table immediately below lays out some of the risks and associated mitigating measures for the tendering and bidding process, which ultimately should benefit both host country and project sponsor.

Table 3: Tender and bid process

Risk	Mitigation
• Non-competitive, non-transparent	• Open bidding to foster competition • Transparent notification of procurement intention and tender process, including timetable

[27] In 2008, the Prime Minister and Minister of Energy both resigned due to the findings of a parliamentary investigation (Eberhard, 2011: 10). In more recent developments, as of September 2011, Tanesco was ordered to pay Dowans Tanzania Limited $123.2million for unilateral termination of emergency power generation contract (James, 2011).

tender and award process • Corruption	• Comprehensive information and documentation packages for bidding and negotiation, pre-bid conferences • Information on avoided costs • Pre-qualification, bid-securities set at appropriate level • Objective evaluation criteria with independent scrutiny

Based on Ferreira, 2004

ICBs are known to have been conducted for 11 of the sample of 23 IPPs. In the East African group, six projects (OrPower4, Tsavo, Rabai, Songas, Namanve and Bujagali) conformed with such bidding practices. In West Africa, ICBs were conducted for three of the projects (Azito, GTi Dakar, Kounoune I and Kribi) and Itezhi Tezhi in Southern Africa.

In terms of gleaning meaning from ICBs versus non-ICBs (which for this sample includes projects that were selectively bid and those that were unsolicited/directly negotiated), of the projects that have faced renegotiation, four were not bid via an ICB (IPTL, Iberafrica, AES Barge and Okpai), with the two exceptions being Songas and OrPower4. The absence of regulatory scrutiny is also noteworthy in each of these four projects. Furthermore, Westmont, which was selectively bid, quit the country after its first seven-year PPA expired. The other non-ICB projects have also, with the exception of CIPREL, Dibamba and the South African MTPPPs, encountered some difficulty or another, which has led to a change in how the project is being developed. For example, Ghana's Takoradi II, has only just started to raise finance for the second phase of the plant. Although reasons for these stumbling blocks may be traced well beyond the presence or absence of an ICB, the correlation is nonetheless revealing.

Furthermore, it should be noted that the success of the ICB process is intricately linked to the number of bids received, with more bidding potentially driving down prices.[28] For instance, it is known that the number of bids submitted to ICBs in North Africa during the first wave of IPP development was generally double to triple those submitted to ICBs in East and West Africa – with only three bidders in Kenya's Tsavo plant and two in the OrPower4 and Songas plants. All three projects have since been pressured to lower tariffs, as discussed repeatedly. In addition, the time and associated cost required to complete an international competitive bid should not be underestimated, with drought-related energy crises often cited as the reason why ICBs have been passed over. Consider for example, Togo's Centrale Thermique de Lome, where the drought conditions of 2006 prompted a move to discontinue a contract with Electro Togo to

[28] On the other hand, given the fact that the cost to mount a bid is high, having an excessive amount of bidders would also not be desirable as some will not bid if they perceive their chances to be low (Rudo, per com, 2010a).

manage a ROT of the plant. Rather than launching an ICB, however, the government chose to negotiate directly with an existing player, Contour Global, who had already been in discussions with the utility. Time and project familiarity proved more important than complying with international bidding practices, which risked extending the project development timeline (Ministry of Energy of Togo, per com, 2010).[29]

Just as alternatives are being considered for strictly independent regulation, including contracting out, to match the institutional and human-resource capacity in a country, the SSA examples here point to the need for more efficient bidding processes that, while focusing on transparency and oversight, also expedite timely outcomes– all much easier said than done, but not infeasible for host countries to adopt and thereby move one step closer to balancing development and investment outcomes. It is important to note, however, that there is, in many instances, albeit not all, significant learning and adaptation, associated with procuring IPPs, including with what many public stakeholders initially regard as complex and cumbersome contracting documents, as will be treated in greater detail in the subsequent section on 'project level factors'. As the range of public stakeholders become increasingly well versed in the processes and contracts, there is the potential for improvement in the overall bidding, as highlighted for example, most recently by Nigeria, where the privatization of state-owned generation and distribution assets attracted 331 expressions of interest, as well as in Kenya's geothermal developments, as described further below.

Reflecting on the mishaps of planning, procurement and contracting and the example of Kenya: The question arises: why do these planning and contracting mishaps occur? In our view the answer lies in the changing nature of power markets across Africa and other developing regions. Previously, the national state-owned utility had sole responsibility for planning and building new generation capacity. But as power markets have been opened to private sector participation, it is not always clear who has responsibility for maintaining security of supply. Often the planning function is shifted to the Energy Ministry which does not have the capacity, resources or experience to undertake detailed power sector planning. The task is often contracted out to consultants who produce a Master Plan, which quickly becomes out of date as global equipment and fuel costs, and other key parameters, change (Malgas and Eberhard, 2011).

It is not only in planning where the absence of poor governance and institutional capacity is evident. There are no clear criteria for allocating new build opportunities to either the incumbent state-owned utility or to the private sector, as previously noted at the outset of this section. Sometimes it is not clear whether plans are merely indicative, whether unsolicited proposals may be considered, or whether plans have legal force in determining which plants the regulator may licence or not. All too often, plans do not translate into timely initiation of competitive bid processes for new plant. And there is often insufficient capacity to negotiate with winning bidders or to conclude sustainable

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[29] Togo's next IPP in the pipeline, a 24 MW wind farm, however, is being procured via an ICB (Ministry of Energy of Togo, per com, 2010).

contracts. Transaction advisers may be appointed, but often there is little continuity and the overall policy framework is lacking that defines which security packages or credit enhancement measures might be offered by government. Hybrid power markets 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.

Kenya, despite its earlier planning deficiencies and forced reliance on emergency rental power, more recently provides an interesting example where progress is being made in dealing with these planning, procurement and contracting challenges. The electricity law assigns responsibility to the Energy Regulatory Commission for electricity planning. Recognising 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, has assisted this committee in developing least cost plans. KPLC was unbundled in 1997 from generation (which is now in KenGen) and so has a neutral stance between the state utility, KenGen, and private 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. Initially, it did this with transaction advisors but now has largely built up this capability internally. Bid documentation and PPAs have largely been standardised and private project sponsors now have a clearer understanding of how the process of procuring new power works in Kenya.[30]

Among the critical lessons in procurement and contracting of IPPs, from Kenya's experience, is that extensive project preparation limits the complexity of contract negotiations. In particular, careful site selection, sub-soil testing and environmental approvals all ensure greater certainty for bidders and reduce the need for renegotiations. Such problems arose during the development of the Rabai IPP; there were also changes to project sites during the tendering of the latest round of the three medium speed diesel IPPs, requiring a postponement of the tendering date submission. In addition, the Government of Kenya took a considerable amount of time to determine the status of Government guarantees. "Kenya is still learning how to procure and contract more

[30] As described by one project sponsor in Kenya, commenting in May 2010, "They have an IPP structure that is working. They have a track record. They can structure new projects based on experience gained from previous projects. And they have a very capable set of teams working in KPLC, the Ministry of Energy/Finance and KenGen. They understand project finance and are not surprised when a developer requests a comfort letter, as one example." The fruits of this approach are evident. Kenya has tendered for three new IPPs, which would add to its existing five – maintaining its lead position in terms of total number of IPP investments in SSA. It is also noteworthy that Kenya has been cited by public stakeholders in both Ghana and Tanzania as having processes that should be emulated (PURC, per com, May 21 2010; EWURA, per com, 2010b).

efficiently: the important point is the commitment to learning and improving," (Castalia, 2011).[31]

Abundant low-cost fuel and secure fuel contracts

The availability of competitively priced fuel supplies for IPPs has also emerged as a key factor in how IPPs are perceived and ultimately whether there is public appetite for more such projects, in large part because fuel is generally a pass-through cost to the utility and in many cases to the final consumer as well. Thus, if the IPP uses a fuel different from the incumbent fuel, and if that fuel is more expensive, there is greater potential for stress on the project. The table immediately below showcases this risk and related, potential mitigating measures.

Table 4: Fuel supply

Risk	Mitigation
• Reliable fuel supply to specification • Adequate resources for life of project (PPA)	• Proven reserves • Alternative supply obligation • Liquidated damages for delivery failure • Cost pass through

Based on Ferreira, 2004

In a number of countries (for example, Cameroon, Ghana, Kenya, Tanzania, Togo, Uganda and Zambia), at the inception of IPPs, low-priced hydropower was the dominant fuel source. In the majority of these countries, IPPs were thermal powered, using a combination of imported fuel oil and domestically procured natural gas.[32] IPPs have helped the countries to achieve greater fuel diversification; however, when the costs of IPPs (other than those running on domestically procured natural gas, namely Songas, and Kribi, as expected from 2012) were compared with state-owned, generally amortized hydropower, the new privately owned generation was seen to be largely more expensive, due partly to the energy/fuel charge.[33] Furthermore, these countries

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[31] One further, related issue arises in hybrid power markets: will the dispatch of state-owned generators and IPPs be transparent and fair? The nature of the contracts between the System Operator and the generators will impact on this issue, as will the grid code and degree of regulatory oversight. This is another issue which requires explicit attention in terms of appropriate policies, governance, and institutional and contracting arrangements.

[32] Major exceptions here are Uganda, where the country's second IPP, Bujagali, will be hydro-based, and Zambia, where the country's first large-scale IPP, Itezhi Tezhi, will also introduce 120MW of hydro-based generation.

[33] Togo's Centrale Thermique de Lome is presently seeking to negotiate a fuel supply contract which would allow it access to 'regional' natural gas from Nigeria, via the West African Gas Pipeline (WAGP). Meanwhile, Ghana's Sunon Asogli plant has, via an interim agreement, started

witnessed a series of debilitating droughts over the course of the 1990s. Drought also wreaked havoc throughout the East African region between 2002 and 2007 and again in 2009, and most recently in the latter part of 2010 and 2011. During this time, the existing hydropower infrastructure proved insufficient, and thermal, provided almost entirely by IPPs, was increasingly integrated into the fuel supply mix (from 10 percent to 60 percent in Tanzania), forcing up the price of power. Although more thermal power may be required, the public perception is that IPPs drive prices up, rather than a number of factors, including drought, which means that gaining public support for such projects is all the more challenging.

OrPower4, Kenya's geothermal IPP, deserves special mention in this context, of hydro-dominant systems, which have diversified with largely imported fuel oil. "At a price of US $29 per barrel of petroleum crude oil, this 48 MW geothermal plant is cheaper to operate than a heavy fuel oil fired plant," (Ormat, 2009). As the price per barrel of oil exceeds US$80 (2011), this statement continues to ring true, along with OrPower's assertion that it is providing cheaper electricity to the national grid than any existing oil fired plants in Kenya," (OrPower per com, 2011). In this favourable environment, OrPower4 is due for a 36 MW expansion, which it directly negotiated with KPLC, due online by 2013 (Ormat, 2011).

Meanwhile, Kenya's Geothermal Development Company (GDC) invited expressions of interest in November (2010) for development of 4x100MW geothermal plants in Menengai. Twenty-one EOIs were received, in February 2011, and 19 firms were pre-qualified, however, the associated Request for Proposals (RfP) have not yet been issued, as GDC completes further feasibility work. In a subsequent development, GDC, invited EOIs for development of 8x100MW geothermal plants in Bogoria-Silali Block. Nineteen EOIs were received in August (2011), 11 of which were from firms that had also expressed interest in Menengai (Mwangi per com, 2011). Although RfPs remain outstanding, the EOIs demonstrate sustained interest in the sector, and represent potentially an important contrast with Kenya's first Geothermal ICB of 1996 (for 13 MW), which saw less than five EOIs and only two firms finally submit bids (Ormat per com, 2011).[34]

At the beginning of this section, the claim was made that when IPPs use fuel that is either cheaper than and/or the same price as the incumbent fuel, they have a greater chance of success, as has been seen in several North African IPPs. There are few IPPs in SSA with secure, low cost fuel sources. There are, however, several noteworthy exceptions. In Tanzania, the natural gas from the Songo Songo field, which was dedicated to supplying the Songas plant and later to fuel IPTL, is cheaper than the

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accessing WAGP gas, which has the potential to alter the cost structure and perceived added costs of IPPs in the West African region, as discussed further below.

[34] Just as geothermal energy and domestically produced gas has started to make a change in the IPP landscape (and for SSA ESIs in general), the emerging hydro IPPs (Bujagali and Itezhi) together with recent discussion about mobilizing coal resources (in Kenya and Tanzania) have the potential to reshape the IPP electricity environment even further and help reduce the impact of imported fuel.

imported fuel oil currently powering IPTL.[35] However, disputes continue and IPTL diesel units have yet to be converted to gas. Also worth mentioning in this context is Ghana's Sunon Asogli Power Plant, which waited more than a year for its fuel (via the WAGP), during which time the plant lay idle (Tsen, 2009). The present interim arrangement for WAGP gas for Asogli has solved the situation temporarily, however, the plant has also been under pressure from the New Patriotic Party (NPP), the opposition party, as to the details of its fuel arrangement (Afede, 2011) (Genser per com, 2011).

The issue then is not simply whether a country has abundant, low-cost fuel, but whether security of supply is guaranteed through fuel contracts well into the future (on average 20 years). Fuel must be abundant and low-cost, both now and later, for it to have a positive impact on outcomes. These many country-level factors are summarised in Table 5.

Table 5: Contributing elements to successful IPP investments within the purview of host governments

CES	Details
Favourable investment climate	-Stable macro-economic policies -Legal and political systems allow contracts to be enforced, laws to be upheld -Good repayment record and investment grade rating -Requires less (costly) risk mitigation techniques to be employed which translate into lower cost of capital and hence lower project costs and more competitive prices - Potentially more than one investment opportunity

[35] Tanzania used the net-back calculation method to establish the gas price for the first 142MW owned by Songas. Although it is viewed to be low ("US$0.55/Mcf"), most of the costs associated with the gas infrastructure are paid separately as part of the capacity charge. In typical projects, these would have been part of the gas price (i.e. US$4.20/Mcf). The same gas price is not offered to IPTL. Under the IPTL PPA, fuel is a pass-through. TANESCO has negotiated with PanAfrican Energy and TPDC to book 100 MMcfd at negotiated wellhead prices (in favour of the additional 40 MW owned by Songas, 145 MW owned by TANESCO, and the next 100MW plant, which may be IPTL or any other plant) starting at US$1.98/Mcf, escalated at 2.2% annually for the first 5 years from July 2007, then to US$3.5/Mcf thereafter, escalated at USCPI. In summary, the gas prices are discounted market prices of an alternative fuel (EWURA, per com, 2010a, 2011).

Clear policy Framework	-Policy framework enshrined in legislation -Framework clearly specifies market structure and roles and terms for private and public sector investments (generally for non-exclusive central purchaser, not, yet, wholesale competition in African context) -Reform-minded 'champions', concerned with long-run, lead and implement framework
Clear, consistent and fair regulatory oversight	-Oversight improves general performance of private and public sector assets -Transparent and predictable licensing and tariff framework improves investor confidence -Cost-reflective tariffs to ensure revenue sufficiency, where possible, as well as targeted subsidies, where necessary -Consumers protected -Perceived independence of regulator
Coherent power sector planning linked to procurement and contracting	-Energy security standard in place; planning roles and functions clarified -Power planning vested with lead, appropriate (skilled, resourced and empowered) agency -Power sector planning takes into consideration the hybrid market (public and private stakeholders and their respective real costs of capital) and fairly allocates new build opportunities among stakeholders -Planning has built-in contingencies to avoid emergency power plants or blackouts - Responsibility for procurement is clearly allocated, plans are linked to procurement and bids are initiated in time - Pre-tender technical and environmental due-diligence on the proposed site is also essential - Procurement process is transparent and, provided numerous bids received, competition ultimately drives down prices - Capacity is built to contract, tender and evaluate effectively
Abundant low cost fuel & secure contracts	-Cost-competitive with other fuels -Contract safeguards affordable and reliable fuel supply for duration of project

3.2 Building up contributing elements to success, at project level

Who were the investors and what did they do to navigate the varying investment climates as well as the changing policy and planning frameworks, including fuel supply? Starting with an evaluation of equity arrangements, this section examines trends in investor behaviour, and how investors secured revenue to service debt and reward equity, particularly in the face of exogenous stresses.

Favourable equity arrangements

Did the presence of local equity shareholders make a difference in project outcomes? Were projects with such participation less likely to face pressure from host country governments to change their contract terms? How did a firm's prior experience with a country play out in terms of the making and breaking of deals? What about the presence of firms with development origins such as Industrial Promotion Services (IPS), Globeleq and Aldwych International as well as DFIs? Table 6 lists each of the projects, followed by the country origins of sponsors and their respective equity share, whether projects faced a change in contract terms and finally if there was turnover of the majority equity partner.

Foreign vs. local: Foreign firms have been the dominant players in Sub-Saharan African IPPs, unlike in Malaysia and China where local IPPs abound (Woodhouse, 2005: 22-3, 91). This should not be surprising, given the limited capital available in countries across the sample; however, it is worth noting, and it does raise the issue of foreign-exchange exposure, treated in the next sub-section.[36] There were only three projects in the pool where local partners were the major and/or joint stakeholder, Nigeria's Okpai and Afam VI, South Africa's Sasol MTPPP, and Zambia's Itezhi project, as referenced above. However, in three of these cases, the majority stakeholder was either the national utility (Zesco, Zambia) or the national petroleum company (NNPC, Nigeria). Also, as previously noted, in Okpai and Afam VI, the power projects fall under the rubric of a state-led gas-flaring-reduction programme, in which oil companies, were engaged in power projects. Although not the major stakeholder, the Republic of Cameroon does hold a 44 equity percent stake in both the Dibamba and Kribi projects, and similar government involvement is anticipated for a range of projects in Zambia, building on the Private Public Partnership model.

Local participation has been cited as a possible means of reducing risk (Hoskote, 1995: 11; Woodhouse, 2005). A total of 9 of the 23 projects have local equity participation, namely, Sunon Asogli , Iberafrica, IPTL,[37] Songas, Takoradi II, AES Barge, Okpai, Afam VI, and Bujagali. To what extent did such local participation impact favourably on outcomes? Of the 10 projects, 6 have encountered some form of change to their contract.[38] Furthermore, in 4 of these 6 projects, either the state utility or another government entity held an equity share, which would indicate that the mere existence of a local partner might not be critical in setting an original sustainable balance. In the renegotiating of terms, how might a local partner make a difference? Kenya's Westmont

[36] Several projects in Nigeria (Ibom and Omoku) have been loosely termed IPPs. Although independent of the national utility, they have been led entirely by the Rivers and Akwa Ibom State Governments, respectively. We have therefore excluded these from our analysis, which focuses on private sector involvement.

[37] At the time of writing, the level of equity (including local equity) is under dispute in Tanzanian court.

[38] See the introduction to Section 3 of this report for further details.

and Iberafrica were both negotiated at the same time under similar policy frameworks. They are the only two examples in the project pool where one had local participation (Iberafrica) and the other did not (Westmont). Iberafrica first voluntarily reduced its tariff and then went on to negotiate a second 15-year PPA, in contrast to Westmont, which quit after failing to come to an agreement on a second PPA. The presence of a local partner may have helped in creating a longer-term solution; however, with just one example, the evidence is not conclusive. Togo's Centrale Thermique de Lome, which came online in 2010, may provide an important example going forward; in this project, 25 percent of project equity must be sold to locals within the first five years, which may prove to be a more sustainable method for balancing investment and development outcomes—a process which, as of October 2011, has just started (Ministry of Energy of Togo, per com, 2010, 2011a).

Table 6: Equity participation in IPPs

Project (alpha by country initial)	Equity partners (country, % of equity held)	Change in contract terms	Equity turnover (#)[39]
Dibamba (C)	AES (USA, 56%), Republic of Cameroon (44%)	N	0
Kribi (C)	AES (USA, 56%), Republic of Cameroon (44%)	N	0
CIPREL (C)	SAUR International, with 88% (JV between French SAUR Group owned by Bouygues, 65% and Electricite de France (EDF), 35%) BOAD (West African Bank for Development), PROPARCO (the Investment and Promotions Company for Economic Cooperation, subsidiary of AFD), and IFC holding the remaining 12%; in 2005 all shares sold to Bouygues (France, 98%), except BOAD (2%)	N	1
Azito (C)	Cinergy (JV between Swiss ABB, 50% and Globeleq, 50%) holds 65.7% of shares, + CDC/Globeleq (11%), and IPS-AKFED (23%)	N	1
Takoradi II (G)	CMS (USA, 90%), VRA (Ghana, 10%), CMS sold shares to TAQA (UAE, 90%) in 2007	Y	1
Sunon Asogli (G)	Shenzhen (China), Togbe Afede XIV (Ghana/local strategic investor)	N	0
Westmont (K)	Westmont (Malaysia, 100%) has sought to sell plant since 2004	-	-
Iberafrica (K)	Union Fenosa (Spain, 80%), KPLC Pension Fund (Kenya, 20%) since 1997	Y	0
OrPower4 (K)	Ormat (USA, 100%) since 1998	Y	0
Tsavo (K)	Cinergy (USA) & IPS (Int'l) jointly owned 49. 9%, Cinergy sold to Duke Energy (USA) in 2005, CDC/Globeleq (UK, 30%), Wartsila (Finland, 15%), IFC (Int'l, 5%) retain remaining shares since 2000	N	1
Rabai (K)	Aldywch-International (Netherlands, 34.5%), BWSC (Danish, but owned by Mitsui of Japan, 25.5%), FMO (Netherlands, 20%), IFU (Danish bilateral lender, 20%)	N	0
AES Barge (N)	Enron (USA, 100%) sold to AES (95%) and YFP (Nigeria, 5%) in 2000	Y	1
Okpai	Nigerian National Petroleum Corporation (Nigeria,	Y	0

[39] It is important to note that many times shareholders are prohibited (by the lenders) from selling, particularly the shareholder with the technical expertise, until after commercial operation (Rudo, per com, 2010a).

(N)	60%), Nigerian Agip Oil Company (Italy, 20%), and Phillips Oil Company (USA, 20%) maintained equity since 2001		
Afam VI (N)	Nigerian National Petroleum Corporation (Nigeria, 55%), Shell (UK/Netherlands, 30%), Elf (Total) (France, 10%), Agip (Italy, 5%)	N	0
GTi Dakar (Sn)	GE Capital Structured Finance Group (SFG) (USA), Edison (Italy), IFC	N	0
Kounoune (Sn)	Mitsubishi (Japan), Matelec S.A.L (Lebanon)	N	0
Sasol (Sa)	Sasol (South Africa, 100%)	N	0
IPTL (Ta)	As originally stated: Mechmar (Malaysia, 70%), VIP (Tanzania, 30% **in kind**), both have sought to sell shares, and actual equity contribution is presently disputed	Y	-
Songas (Ta)	TransCanada sold majority shares to AES (USA) in 1999 and AES sold majority shares to Globeleq (UK) in 2003[40], all preferred equity shares were converted into "Loan Notes" in June 2009, only common shares remain	Y	2
Centrale Thermique de Lome (Tg)	Contour Global (USA, 80%%), IFC (20%)	N	0
Bujagali (Ug)	Sithe Global (USA, 58%), IPS-AKFED (32%), Government of Uganda (10%)	N	0
Namanve (Ug)	Jacobsen (Norway, 100%)	N	0
Itezhi (Z)	Tata, (India, 50%), Zesco (Zambia, 50%)	N	0

Notes: N: no change in contract terms and/or in original project concept as laid down in PPA, Y: yes change in contract terms and/or original project concept.

***Origins, experience and mandate of partners*:** Although globally IPP investments during the 1990s were led by a host of American and European investors who saw returns in their home markets diminishing, there was also a wave of investors originating from developing countries, particularly from Malaysia. In both Kenya and Tanzania, this report has profiled Malaysian firms committing to projects (including in one of the projects, Westmont, cited above, where the firm took neither foreign nor local partners). While it would be inaccurate to say that these firms overlooked the higher risk profiles of the African continent (and/or did not ultimately charge higher returns), there may have been a greater willingness to consider investments in the first place.

[40] Due to complexity, turnover is detailed in Appendix A.

While the number of developing/emerging-country-based firms appears to be growing, including most recently as noted in Tata's (India) presence in Itezhi, three of the southern-based firms are trying to sell their shares (Mechmar and VIP in IPTL and Westmont). Thus, the home country of the firm does not mean that project equity is set for life, or that such a firm is best positioned to service debt and reward equity, since each of these sales appears to be motivated in part by an inability to do just those things.

A more revealing aspect than the nationality of the firm appears to be a firm's experience and mandate. Across the pool, examples pile up of firms being actively involved in the country prior to their IPP investment. Union Fenosa, the parent company of Iberafrica, had an existing relationship with Kenya through an information-technology contract. IPS, a major shareholder in Tsavo, Azito and Bujagali, had operated in Kenya since 1963 and in Côte d'Ivoire since 1965. Furthermore, IPS, via the Aga Khan Foundation, has ties to the East African region dating as far back as the early 1900s. The Commonwealth Development Corporation (CDC), from which Globeleq was spun off, had a 50-year history in Tanzania. The Netherlands Development Company (FMO), which holds a majority share in Aldwych International, the main sponsor of Kenya's Rabai IPP, has been active in SSA since the 1960s. It may be argued that long-term relationships, with strong local management, appear to have contributed to the staying power of firms and often the rebalancing of contract terms, for certain projects. Sasol's origins in South Africa date to 1950 when the company first sought to commercialize its coal-to-liquids technology (CTL), for which it would later become known.

The mandate of the firm also appears to play a central role in the investment decision as well as the terms of the deal. Until recently, the two firms that were increasing (rather than maintaining or reducing their stakes) were Globeleq and Industrial Promotion Services. Globeleq holds a 43 percent share in Côte d'Ivoire's Azito, 30 percent equity in Kenya's Tsavo and 56 percent in Tanzania's Songas. IPS holds a 23 percent share in Azito, and together with Duke Energy, a 49.9 percent share in Tsavo. IPS is also leading development of Uganda's Bujagali project, and a 32 percent shareholder in equity. Although a smaller player than either Globeleq or IPS, Aldwych International, has also made significant inroads via Rabai in Kenya and is presently evaluating further expansion.

Although Globeleq, IPS and Aldwych are driven by commercial interests, these firms have emerged from agencies with a strong commitment to social and economic development. Globeleq remains wholly owned by Actis, which originated from CDC, the private sector promotion arm of the UK Department for International Development. Globeleq's focus has changed somewhat in recent years, but the origins are key to its involvement (and continued interaction) in SSA.

"From 2002 to 2006, Globeleq acquired and developed a portfolio of approximately 2,500 MW of generation assets using equity capital. In 2007, Globeleq took advantage of very attractive market valuations and divested its assets in the Americas, Asia and North Africa, more than doubling the invested capital. Globeleq retained its brand, a pipeline of development projects and the SSA assets/investments which provided a

platform for continuing business. Globeleq Generation Limited will develop, build and operate new power generation businesses in the emerging markets. In the short to medium term - due to market conditions resulting from the financial crisis, it is expected there will be attractive investment opportunities for Globeleq, with owners seeking to sell either operating or late stage greenfield development projects," (Globeleq, per com, 2010b).

IPS is the operating arm of the Aga Khan Fund for Economic Development (AKFED) in the industrial sector throughout Asia and Africa. Here, 'development' speaks perhaps louder than for any other firm, "IPS will only invest in projects with: a high developmental impact and a reasonable IRR -the IRR for Tsavo is approx 17-18%, for Bujagali, 19% which is considerably lower than typical IRRs in the region for these sorts of projects," (IPS, per com, 2010).

Aldwych International is an initiative of the Dutch FMO. While projects for these firms have to make commercial sense, they must also serve a clear developmental function for the country/community. It is this commitment that appears to be particularly helpful in the face of African risk.

Rabai, a case study: Reviewing Aldwych International's experience in Rabai helps to illustrate this point. The firm faced three different hurdles along the road to development and yet has stayed the course. Firstly, in the original tender, Simba, a Kenyan firm had the lowest bid; however, it was subsequently determined that Simba was incapable of developing Rabai. KPLC then awarded the project to Aldwych. In response, Simba brought a case to the Kenyan Public Appeals Board against KPLC. Simba lost its appeal but then appealed to the High Court. Eventually, Simba and KPLC settled out of court. Although Aldwych was not directly involved in the case, Simba's appeals caused a project delay of eight months (primarily due to the fact that lenders were unwilling to commit due to the controversy). The delay had the further effect of reducing Aldwych's projected IRR of Rabai by at least 1 percent. The second major hurdle faced by Aldwych was that in December 2007 (two months after the end of the action in the High Court) country-wide protests were sparked by the election results. This civil unrest further delayed financial close as lenders would not commit to a project in an environment where there were active allegations of political fraud. Thirdly, the global financial crisis struck in the 4th quarter of 2008, at the time when the project was just reaching financial close and also at a time when Aldwych was seeking to raise more capital (Aldwych International, per com, 2010a). Financial close did happen, and it should be added successfully, with the project picking up Project Finance International's Deal of the Year (in 2008), despite the setbacks it had encountered since the tender. Finally it is worth noting, none of the projects with involvement of such firms with development origins, except Tanzania's Songas, has seen any changes in contract terms,[41] which may signal a greater perceived balance from project inception as well as a better ability to withstand public pressure.

[41] The changes to Songas' PPA include: (1) US$103 m. AFUDC buy-down; (2) the use of escrow funds to buy down the AFUDC; (3) freezing the liquidity facility, which was meant to be

DFIs holding onto equity: Meanwhile, the presence of DFIs persists in project equity. Six of the IPPs saw DFIs pick up equity shares. The International Finance Corporation (IFC) recently acquired a 20 percent share in Centrale Thermique de Lome; IFC also holds a 5 percent share in Tsavo's equity and is a shareholder in GTi Dakar in Senegal. Until 2005, IFC also held, together with the West African Bank for Development (BOAD) and the Investment and Promotions Company for Economic Co-operation (PROPARCO), a 12 percent share in CIPREL. IFC and the German Investment and Development Corporation (DEG) each had an approximately US$12 m. equity investment in Songas, with both organizations selling their shares after the IPTL dispute became known. FMO maintains a 24 percent share in Songas (excluding the expansion of 65 MW), as well as a 20 percent share in Rabai (apart from its shareholding in Aldywch). CDC, independent of Globeleq, also holds a 6 percent share in Songas (excluding the expansion). It should be reiterated here that none of these projects, save Songas, has seen any contract changes.

Equity turnover: Of the 49 original equity partners in the sample pool of 23 projects, 7 have exited from 5 different projects. This statistic, however, tells only part of the story. First, as previously indicated, three shareholders from developing regions have been actively trying for several years to sell their assets (both shareholders in Tanzania's IPTL and Kenya's Westmont). In addition, there are reports that General Electric (GE) has tried to sell its shares in GTi Dakar since conditions began worsening with regard to the fuel supply in 2006. In the case of IPTL, Mechmar, the lead shareholder, has indicated that the arbitration settlement ultimately hurt equity partners, which has motivated the sale. VIP, the minority shareholder, cites the following causes: oppression by the majority shareholder; fraud by Mechmar in inflating the IPTL capital cost; and failure by Mechmar to pay its equity contribution (i.e. the project was 100 percent debt-financed). There has been no resolution of this conflict, and no willing buyers. In the case of Westmont, the firm did not secure a second PPA, due to disagreement over tariffs, and has, since 2004, been seeking to sell the asset. Second, if one focuses exclusively on majority shareholders, four of the majority shareholders in the 23 projects have sold shares at least once and two have been actively seeking to do so for at least five years.

The repeated refrain from most sponsors is that the sale of assets is motivated primarily by changing circumstances in home markets and/or related to corporate strategy; that is, the sale has little to do with host country actions and reactions and/or poor investment outcomes, namely, the ability to service debt adequately and reward equity.

How does this refrain square with the contract changes? The majority shareholders in two of the projects that saw contract changes exited after such a change (namely, CMS in Takoradi II and Enron in what is currently known as AES Barge). Furthermore, as

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replenished and be accessed only in the case of partial or non-payment by TANESCO; and (4) preferred equity conversion to "loan notes".

noted above, Westmont has sought to sell the plant since it failed to renegotiate a second contract, and Mechmar has actively been seeking to sell its shares post-renegotiation.[42]

While fewer than expected investment outcomes may be partially motivating sales, turnover does not in and of itself appear to be challenging the long-term sustainability of contracts, since in nearly all cases sellers have found willing buyers to take over the original or recently renegotiated PPAs.[43] One stakeholder went so far as to assert, '[equity turnover is a] healthy factor in a maturing market. It is a good sign when investors come and go – not a bad or threatening thing.' The return of the government as shareholder, as planned in the case of Tanzania's IPTL, would, however, signal that some markets might actually be less mature than expected.

What then, in the end, have been among the most critical characteristics of equity arrangements that have led to project sustainability? Overarching characteristics appear to be firms' prior experience in a country or region, the presence of firms with development origins and development finance institutions.

Debt arrangements: global and local

With debt financing often covering more than 70 percent of total project costs, competitively-priced financing has emerged as a key factor in successful projects. How and where to get this low-cost financing is the challenge, but possible approaches in the African cases lie in DFI involvement, credit enhancements, and some flexibility in terms and conditions that may allow for possible refinancing.[44] 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.

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[42] As indicated previously, authors do not cover the first phase of Bujagali's conceptualization spanning the mid 1990s until 2003 and involving AES (which subsequently wrote-off tens of millions of dollars in development costs), reporting instead only on the project from its second phase, starting in 2005.

[43] The three exceptions here are again the Westmont plant, where the first PPA has expired and which was shrouded in controversy, IPTL, which has been embroiled in lawsuits, which could have biased investment/resale opportunities, and GTi Dakar, where there have been persistent disputes with regard to fuel supply, among other things.

[44] It is important to note the emergence of two Chinese firms, Shenzhen in Sunon Asogli (Ghana), and Sino Hydro in Bui Hydro (Ghana) and Kafue Gorge (Zambia). In the case of Bui, Sino Hydro is the contractor, and the majority of project costs are covered via concessional loans from the government of China (as noted at the outset in footnote 10). The extent of Chinese government/export credit agency involvement in these projects is presently being reviewed by the authors, as such involvement could represent a new element and be a significant source of investment for other African IPPs. Foster and Briceno-Garmendia report on the general phenomenon of non-OECD funders, including the emergence of increasingly significant funding flows from China to SSA (2010: 78-79). In addition, it is important to note, the Export and Import Bank of India (EBRD) has agreed to a US$50M loan for Itezhi (Zambia) and is presently in negotiations for additional funding.

While there is no uniform pattern in the debt financing for the projects considered here, there is a series of trends for how investors handled costs as well as practices that may ultimately contribute to success. Important to note at the outset is that, although non-recourse project financing is the norm for privately financed electric power plants in developing regions, this sample of 23 projects saw several notable exceptions, including Nigeria's Okpai and Afam VI plant, which were 100 percent financed by the balance sheet of equity partners, together with the second phase of Songas, which, however, was largely refinanced via a World Bank loan in 2009 (Globeleq, per com, 2010a). Westmont, Iberafrica and OrPower4, until 2008, were also all financed entirely with the balance sheets of their sponsors. For Westmont and Iberafrica, the reason cited for this arrangement was that insufficient time was available to arrange project finance as plants had to be brought on line within 11 months. For Orpower4, reasons are linked, by the sponsor, to the lack of a security package, which was not forthcoming until 2006.

***DFIs and their impact on projects*:** With limited appetite for projects among many commercial banks, development finance institutions are conspicuous in providing credit to projects across the pool. Such entities participated in nearly every IPP, including significant participation on the part of the World Bank/IDA (Bujagali, CIPREL, Kribi, Songas), IFC (Azito, Tsavo, Bujagali, Dibamba, GTi Dakar, Kounoune I, Kribi), CDC (Tsavo, Azito), European Investment Bank (Songas, Bujagali, Kribi), DEG (Tsavo, Azito, Rabai, OrPower4, Bujagali), FMO (Azito, Rabai, Bujagali, Dibamba, Kribi), African Development Bank (Azito, Bujagali, Dibamba, Itezhi, Kribi), West African Bank for Development aka BOAD (Kounoune I) PROPARCO (Bujagali, Kounoune I, Kribi, Rabai), Emerging Africa Infrastructure Fund (Rabai), European Financing Partners (Rabai) and KfW (Bujagali), AFD (Bujagali, Kounoune I) and NORAD (Namanve). Kribi has also been the recipient of a loan from the Banque de Developpement des Etats de l'Afrique Centrale (BDEAC). In addition, Centrale Thermique de Lome, Contour Global's project in Togo has seen the involvement of the Overseas Private Investment Corporation of the United States (OPIC) via a US$147m. loan package.

Much of this involvement is related to the long history of DFI activity throughout Africa coupled with the real and perceived risks across the continent, which preclude private investors from filling the financing gap. The involvement is also linked, however, to the broader mandate of power sector reform. Nevertheless, it is noteworthy that African IPPs, which by their very definition imply private investment, had such significant public involvement. DFI involvement while critical to many projects may in some instances actually crowd out private initiatives. Consider for instance the recent concessionary loan of 40 billion cfa by AFD (or approximately US$84 million based on present FX rates) which has been allocated for public sector refurbishment of plants in Senegal. In the wake of this loan, discussions with regard to two new IPPs have stalled, along with additions to an existing IPP. One must ask whether this is the most efficient and fair application of (public) funds, given the precedent of inviting private sector participation into the sector.

Although projects with DFI funding tended to take longer to reach financial closure,

sponsors did cite clear benefits; multilateral and bilateral development institutions helped maintain contracts and resist renegotiation in the face of external challenges such as Kenya's droughts when developers were pressured to reduce tariffs. A particularly revealing contrast is in the two Kenyan plants, OrPower4 and Tsavo, negotiated under the same policy framework. The former plant initially saw no multilateral involvement in either its equity or debt,[45] whereas, for the latter, IFC arranged all the debt and took a 5 percent equity stake. Tsavo has since resisted pressures to reduce its tariffs by the Kenya Power and Light Company (KPLC) and the government, with the presence of a multilateral development institution cited as among the reasons. OrPower4, on the other hand, has ultimately reduced its tariff for the second phase of the plant. Tanzania's Songas project, for which the World Bank together with EIB financed all the project debt, also deserves special mention here. The project took almost a decade to reach financial closure, but the World Bank played an instrumental role in, among other things, pressuring the IPTL arbitration, which ultimately led to what has been widely perceived as more balanced contract terms. In commenting on the hurdles faced during financial close, including civil unrest following the 2007 elections, a spokesperson at Aldwych also mentioned the following: "The fact that all lenders at the table were bilaterals also meant that they could appreciate the level of political risk/instability and ultimately wait it out until a peaceful solution was brokered (Adlwych International, per com, 2010a).

Locally denominated finance: Locally denominated financing appears to be among the solutions for more sustainable foreign investment; however, capital markets in many African countries are insufficiently deep or liquid to provide such financing for all projects. Three exceptions in the project sample are Kounoune I of Senegal Namanve of Uganda, and Kribi of Cameroon. In Kounoune I, the project saw financing from the Banking Company of West Africa (CBAO), a local Senegalese private bank. For Uganda's Namanve project, project debt includes a commercial loan from Uganda's Stanbic Bank Ltd (which is back-stopped by Standard Chartered Bank UK). What has yet to emerge is the likes of financing in Morocco's Tahaddart, a 384 MW CCGT. It negotiated a locally denominated PPA, due to the fact that all of its debt (€213 m.) was financed by local banks. This local financing was aided by a number of factors, including the state utility's prominent role in the plant (holding nearly 50 percent of total equity) as well as the fact that Morocco's commercial banks have a significant degree of state involvement.[46] With or without state involvement, no other country in Africa has, as yet, managed to arrange this level and depth of local financing for IPPs.

The main drawback for IPPs without locally denominated finance may be seen when

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[45] In 2009, DEG arranged a US$105 m. loan (Ormat, 2009).

[46] Banque Centrale Populaire (BCP) put up 1300 m. Moroccan dirham (MAD) and MAD960 m. was extended by a consortium of banks consisting of BCP as the lead lender, the Banque Marocaine pour le Commerce Extériere (BMCE) and Crédit Agricole (CNCA). Average exchange rate for the Moroccan dirham in 2003, the year that construction started, was 10.95MAD=1.00EUR (Interbank rate).

projects undergo the effects of macroeconomic shock and currency devaluation. Over the course of the last decade Ghana, Kenya and Tanzania saw serious creeping devaluation, with their currencies losing more than 100 percent, 200 percent and 400 percent of their value, respectively, over the 1990s, which has inevitably had an impact on capacity charges. Most recently, Uganda has seen currency deprivation, which coupled with increases in international fuel prices, prevented the utility from meeting its financial obligations to IPPs, including emergency power projects. With every such instance, there has been pressure to reduce such charges as well as to reconsider IPP development.

In closing this overall discussion of debt arrangements, it is worth noting the experience of Bujagali, which (in contrast to recent reports from Uganda, mentioned above) saw an oversubscription of debt in 2007, with the debt portion amounting to US$670 m, which is unprecedented for SSA African IPPs (IPS, per com, 2010). At a total investment cost of US$860 m, Bujagali is quadruple the investment of the average SSA IPP, at approximately US$190 m. Much may be attributed to and learned from the way in which the project was structured, the development partners and the PRG (as will be discussed in the following sections).

Securing revenue: the PPA

All of the projects evaluated had a long-term power purchase agreement with the incumbent state-owned utility to ensure a market for the power produced and to secure revenue flows for debt and equity providers.

In addition to indicating who would buy the power, the PPAs detailed how much power capacity would be available as well as capacity and energy charges. How plants would be dispatched, fuel metering, interconnection, insurance, *force majeure*, transfer, termination, change of legal provisions, refinancing arrangements and dispute resolution were 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. Nearly all of the contracts specified some form of international dispute resolution and a minimum availability. The table immediately below outlines three different areas, and associated risks and mitigating mechanisms, some of which will be treated in greater detail, in the text below.

Table 7: Construction, Operational, and Revenue Risk

Area	Type of Risk	Mitigation
Construction	-Late completion -Reduced output -Inefficient (high heat rate) -Environmental compliance	-Turnkey, lump sum, date certain contract -Liquidated damages for performance failure
Operational	-Low availability -High operating cost	-Fixed fee contract with performance bonuses

		-Operational guidelines and penalties/termination for performance failure
Revenue	-Creditworthiness of Power Purchaser -Poor billing and collection -Demand for electricity -Non-dispatch -Currency convertibility and transferability -Devaluation of local currency -Inflation -Change in fuel prices	-Accounting and financial information available on power purchaser -Long term power purchase agreements -Sovereign guarantees -Front-loading of tariffs -Escrow accounts -Dollar denominated contracts -Indexation of key costs -Local currency financing (established financial markets)

Based on Ferreira, 2004

Sponsors negotiated or were granted outright US dollar- PPAs, thereby reducing project sponsors' exposure to currency devaluation, which in certain cases was severe. How, then, did the PPAs fare over time? As mentioned at the outset, the bulk of projects in this sample have endured or are, having reached financial closure, on the road to being cornerstones of the power supply, and their contracts have largely been upheld (viz. CIPREL and Azito in Cote d'Ivoire, Iberafrica, Tsavo and Rabai in Kenya, Afam VI in Nigeria, Centrale Thermique de Lome in Togo, Bujagali and Namanve in Uganda). Immediately below, we summarize some of the (few) contract changes that have occurred.

Costs in Kenya's first wave of IPPs were inflated in part due to the short duration of contracts (only 7 years). With Iberafrica facing ongoing pressure to reduce its tariff, coupled with an interest in negotiating another contract, the sponsor voluntarily reduced its capacity charge, enshrined in the PPA. Iberafrica's second and third PPAs are notably longer than its first (and with second negotiations (of 1999/2000) presided over by the then Electricity Regulatory Board, tariffs have been deemed significantly cheaper) (KPLC, per com, 2010). The changes in Kenya's OrPower4 and Tanzania's Songas projects have also been related in part to the final amount of the capacity charge (as originally spelled out in the PPA).[47]

For Nigeria's AES Barge, initially sponsored by Enron, the renegotiations of 1999-2000 brought about several changes in the PPA, including a change in the fuel specifications (from liquid fuel to natural gas), which led to a major reduction in the fuel charge for the off-taker. The subsequent arbitration with AES Barge involved, among other things, reconsideration of the availability-deficiency payment as well as the tax exemption. In

[47] It is, however, worth reiterating in this context that failure to agree on both the security package and the capacity charge contributed to delays in the development of OrPower4's additional 36 MW.

each of the cases reviewed here, it has been the original terms of the PPA that have in hindsight been viewed as unsustainable for the host country and therefore challenged. The case of Tanzania's IPTL is slightly different. Although the contract was considered initially unsustainable due to the added capacity of Songas, the IPTL arbitration was prompted by what was deemed a breach in the PPA, namely, the project sponsors' substitution of medium for slow speed engines, without passing on the capital cost-savings to the utility, as per the PPA.[48]

The PPA has been a central document; and in certain cases, as noted above, it has been the focal point of the discussions when deals have been considered out of balance, but the overriding take-away is that deals and contracts have endured, over time.

Credit enhancements and security arrangements

The menu of options and their applications: The underlying credit risk of the projects has been largely dealt with via a suite of credit enhancements, namely guarantees, insurance and cash (which has taken the form of escrow accounts, liquidity facilities and letters of credit of varying amounts and tenures).

As summarized most recently in Kenya, where government guarantees have not been used, various combinations of the following enhancements have been offered (Castalia, 2011):

- **Escrow accounts**, where KPLC channels revenues from a group of defined customers with good payment records into a separate account that may not be used to meet any other financial obligations until after the IPP's invoice has been paid. The amount in the escrow account is generally equivalent to about 120 percent of the monthly invoice from the IPP. This arrangement is in place for the Tsavo plant and defined customers were agreed on during PPA negotiations and are periodically reviewed and adjusted.
- **Letters of comfort** from the Government, covering political risks and force majeure. These letters do not qualify as sovereign guarantees due to the limited events that fall within their scope.
- **Partial risk guarantees** (PRGs) from IDA, supported by political risk cover from MIGA. The PRG covers against the risk of a government (or government-owned entity) failing to perform its contractual obligations.

For instance, in addition to the escrow account noted above, the Tsavo plant in Kenya has a stand-by letter of credit from KPLC, which covers three months billing of approximately US$12 m., which falls away after debt repayment in 11 years (KPLC, per com, 2010). It is known that a minimum of 13 of the 23 projects had some form of cash

[48] It should be noted that while this dispute was resolved, a subsequent and prevailing dispute relates to the level of actual equity in the project which in turn affects WACC and the allowed rate of return.

security arrangement, with typical terms being between one and four months capacity charge in reserve.[49]

Not surprisingly, the number of credit enhancements appears to diminish as risk profiles improve. However, there are noticeable exceptions such as the first wave of plants in Kenya (Westmont and Iberafrica), where the risk appears to be entirely reflected in the (higher) capacity payments negotiated; however, corruption was also alleged in both of these plants. Thus, the 'security arrangement' may lie not in a letter of credit, but in an informal agreement among sponsors.

Of the many different credit enhancements, it is sovereign guarantees that have been most commonly employed. Such guarantees are known to be extended for at least 10 of the 23 projects in the pool: Tanzania's IPTL, Nigeria's AES Barge, Côte d'Ivoire's Azito, Ghana's Takoradi II (phase I), both GTi Dakar and Kounoune I in Senegal, Togo's Centrale Thermique de Lome, Uganda's Bujagali and Namanve and Zambia's Itezhi. Several of the projects without guarantees (Tsavo and Rabai) were, however, given added assurances by the government, in the form of comfort or support letters, through which political risk is assumed. Furthermore, in the case of the Okpai plant in Nigeria, security in the form of the state-owned oil company's revenues was extended. Thus, if the off-taker defaults, NNPC, among the most liquid firms in the country, is liable.

World Bank partial risk guarantees are seen in three of the projects: Azito, Bujagali and Kribi.[50] In these instances, the partial risk guarantee (PRG) covers all debt of the commercial banks on agreed risks that have been guaranteed by the host government, i.e. if the project company defaults, and the sovereign guarantee is not honoured, then

[49] The security arrangement for Kenya's Tsavo plant is detailed in the text, and OrPower4 has since been granted a similar security package. It was specified that Tanzania's IPTL would have an escrow account equivalent to between two and four months of capacity charge, but this account has not been established. Songas was granted an escrow account for the first 115 MW, with the government matching every US$1 spent by the project company. No escrow account was required for the Songas expansion; furthermore, the escrow account was used in part to help buy down the AFUDC. The project also negotiated a liquidity facility equivalent to four months capacity charge for the first three years, declining to two months starting in year four through the remaining years of the contract. Uganda's Bujagali has a liquidity facility backing the PPA. Côte d'Ivoire's Azito plant has an escrow account equivalent to one month's capacity charge. Zambia's Itezhi project has a three month escrow account. GTi Dakar in Senegal was given an escrow account, and for Kounoune I both an escrow account and letters of credit were extended. In Ghana's Takoradi II, there is a US$ 3 m. Letter of Credit provided by government; other Ghanaian projects are currently under review by authors. For Centrale thermique de Lome in Togo, the project has an escrow account equivalent to one month of full operation and a letter of credit of two months of full operation. The letter of credit reduces to one month after two years of no incident of payment, and falls away after four years of no incident of payment.

[50] In addition a PRG for Kounoune I was approved by the World Bank but was ultimately not signed by the Government of Senegal, as the lender that the PRG would have covered was still willing to fund the project (IFC, per com, 2010a).

the PRG (backed by IDA) pays the commercial lenders; IDA then claims repayment from government (World Bank, 1997, 1999; IFC, per com, 2010a).

In addition, other measures have been engaged. Both AES Barge and Centrale Thermique de Lome have political risk insurance provided by OPIC. OrPower4, and Bujagali have MIGA guarantees, largely relating to currency inconvertibility, expropriation, and political risks.

Impact of credit enhancements? What, then, is the relationship between such credit enhancements and the sustainability of projects? To what extent have they been effective in attracting lenders? And to what degree have such mechanisms helped keep projects intact or led to a swift resolution, in the face of external pressures?

In a novel development recently undertaken in Kenya, during the procurement of the three medium speed diesel IPPs, bidders were asked to propose three different price scenarios based on different levels of credit enhancements, namely: 1) a Government of Kenya sovereign guarantee; 2) a PRG from IDA with a political risk cover from MIGA; and 3) no guarantee (Castalia, 2011). The outcome resulted in the most expensive bids associated with the 'no guarantee' third option. The least costly for the Government ultimately proved to be the second option of IDA PRG coupled with political risk cover from MIGA.

There is evidence for Azito's and Bujagali's partial risk guarantee being among the keys to commercial lending (World Bank, 1999). In the case of Bujagali, the PRG was instrumental in motivating and solidifying the involvement of four commercial banks, which completed the funding requirement (together contributing US$115 million), matched the maturities of other (IFI) lenders of 16 years, and provided very competitive pricing. Some have likened the PRG to a hammer effect, with the World Bank guaranteeing what the government has already guaranteed and thus making the government's commitment two-fold. However it should be noted that this instrument is not necessarily appropriate for all SSA IPPs since PRGs are typically used in situations where the project is large, the country is in an early stage of reform and when there are commercial lenders. Furthermore, the government of the country has to request the PRG; thus, it must be a significant project in the eyes of both the government and the World Bank, which explains why this instrument was used for Azito and Bujagali (Rudo, per com, 2010b), and most recently for Kribi. That said, in projects without PRGs but with DFI involvement, the security arrangements and credit enhancements are similar, with the DFIs generally accepting the political risks (such as Azito and Songas)

The lack of sovereign guarantees had been cited as the main obstacle to developing the second phase of Ghana's Takoradi II. In Kenya, the only country in the SSA pool not to extend any sovereign guarantees since it first introduced IPPs in 1996, stakeholders in Tsavo indicated that, without such a guarantee, the presence of the IFC became critical, both to help arrange debt and share in equity.

Other security arrangements have been used in abundance in Kenya, including a suite of escrow facilities, which, it should be noted, have created a contingent liability on

KPLC's balance sheet, hampering it from raising letters of credit required for the firm's transmission and distribution businesses (KPLC, per com, 2010). Government guarantees were recently tabled again, and debated in cabinet, however it looks like government will provide only letters of support going forward and retain its no-guarantee policy. Although, project sponsors as well as KPLC cite the absence of sovereign guarantees as hampering the ability to raise private finance, ERC's rejoinder to this charge is that IPPs have been introduced to help commercialise the sector; government guarantees work against this goal, and MIGA and other risk insurers are available.

Are they really still needed? Why, though, is there an ongoing necessity for such credit enhancements if Kenya has five IPPs to its name, a proven track record of payment via KPLC and the promise of six additional IPPs in the near-term? While KPLC is creditworthy, "it is still not an investment grade company," (Aldwych International, per com, 2010b); "creditworthiness is in the eye of the beholder – and...subject to interpretation and the risk profile that a lender is willing to accept. They [KPLC] are not investment grade, so the rest is subject to looking at the details of their credit and their liquidity position - particularly vis a vis their short term obligations," (Rudo, per com, 2010c).

Finally, it is important to note that in no projects have the sovereign guarantees, political risk insurance (PRI) or PRGs been invoked, including in those projects which ultimately have faced a change in the contract (namely, AES Barge, IPTL, OrPower4 or Takoradi II). Recourse to international arbitration has only been made in the case of IPTL, with the arbitration serving to shave US$30 m. off the investment cost. In addition, there is evidence that a MIGA delegation was sent to ascertain the facts when, in the case of Kenya, OrPower4 was pressured by both the government and KPLC to reduce its tariff, but the guarantee was never officially invoked. Although pressure from KPLC continued after the MIGA visit, pressure from the government subsided.

In concluding, it may be helpful to reflect on the overall application of security arrangements and credit enhancements. Although there is some variation in the project sample, by and large the variation is limited, with the size of the project, the track record of the regulatory regime, including its stability and credibility, and the credit worthiness of the off-taker, being the main determinants. While there is resistance to government guarantees on the part of some country stakeholders, as noted above, project developers and multilaterals, chief among them the World Bank, maintain: "the first level of support has to come from the government"(World Bank, per com, 2010).

Furthermore, it is important to note that there has been very little evolution since the first set of IPPs, with all projects supported by a PPA, as described in the previous section, and the credit risk largely carried by a government guarantee. The PPA remains required where there is no developed power market, along with a government guarantee, where the off-taker is not credit worthy, which helps explain why these credit enhancements are seen in most Sub Sahara African IPPs (IFC, per com, 2010a; Rudo, per com, 2010b). Contrast this situation with other developing regions such as middle income countries of Latin America where the PRG and other credit enhancements and

security arrangements are virtually absent due to the fact that power markets are in operation, and local lenders are "in the driver's seat and generally very comfortable with local developers and regulation" (World Bank, per com, 2010).[51]

Positive technical performance

Virtually all IPPs in the sample have shown positive technical performance, with n exception noted in the case of GTi Dakar and Kounoune I in Senegal (IFC, per com, 2010b; CRSE, per com, 2010). When asked generally about the most favourable aspect of the IPP experience to date, one public stakeholder simply indicated: "their technical performance," (ERC, per com, 2010).

The performance of IPPs is generally superior to that of state-owned plants. An argument for extending WAGP gas to the Sunon Asogli Power Plant was premised in part on the superior technical performance of Sunon to VRA (PURC, per com, 2010). The Ministry of Energy of Togo has indicated that Centrale Thermique de Lome's technical performance is more efficient than the state-owned counterpart. "For instance, from the 64 MW installed for CEET [the state-owned utility], only 25MW was available in December 2010," as opposed to CTL's 100 MW (per com, 2010, 2011).

In terms of availability, in Kenya, between 2004 and 2006, IPPs had an average availability of approximately 95 percent versus KenGen's thermal plants, which averaged 60 percent.[52]

Strategic management and relationship building

Once 20-year contracts are in place, it would seem that the deal is set and the revenue secured, with clear provisions to ensure debt repayment and reward equity. There are, however, several other interrelated actions that deserve mention here. One involves relationship building, including via local partners (as previously discussed) and community social policies adopted by sponsors. Another relates to how sponsors handle the onset of stresses, including through capacity charges and refinancing.

In terms of social policies, numerous project sponsors have adopted outreach programmes to improve relations with local communities. For instance in Kenya, Tsavo

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[51] It should, however, be noted that for IPPs in Central Asia and or for cross border projects such as Laos to Thailand (Nam Theum II), a PRG and/or other 'strong' credit enhancements would be employed. Also noteworthy is that in the middle income Latin American countries cited above, due to the privatization trajectories, there were few IPPs per se, and in the few cases where there were, e.g. Colombia, there is evidence of involvement by bilateral and multilaterals to help back the investments (Rudo, per com, 2010b).

[52] KenGen presently operates a plant (Kipevu I, 75 MW), similar to Tsavo (Kipevu II, 74 MW), which is out-performed by Tsavo (KPLC per com, 2010). Furthermore, KenGen recently raised cash via a bond in the Kenyan Capital Markets to build a project similar to Rabai, Kipevu III (120MW in Mombasa). This will allow KPLC, which will have a PPA with KenGen, to be able to compare the cost of the KenGen project with the costs of an IPP model, such as Rabai, which also has a PPA with KPLC (Aldwych International, per com, 2010a).

power set up a US$1 m. community development fund for the duration of the 20-year PPA, from which grants of $50,000 each are disbursed each year to benefit environmental and social activities in Kenya's Coast Region. Iberafrica has a social responsibility programme, and IPTL also is an active donor to its immediate community. CMS's social responsibility involvement in Ghana (before it sold its shares to TAQA in 2007) included providing scholarships for secondary and tertiary education as well as support for medical clinics and the construction of drainage systems. Bujagali also has a suite of social outreach programmes. Although the sums are not significant, these programmes, particularly when well advertised, have the potential to win allies and counter the stereotype of IPPs.

Another perhaps more significant action is how sponsors cope with stress, such as macroeconomic shock and associated currency devaluation or pressure from host governments which perceive costs to be too high. Although anecdotal, there is evidence of how strategic management helped put Kenya's Iberafrica back on track, in contrast to Westmont, where no such action is in evidence. Kenya's Iberafrica has dealt with two stresses: drought and alleged corruption. It is important to reiterate in this context that the project was also up for a contract renewal at the time when the following actions were undertaken. According to stakeholders at Iberafrica, the IPP voluntarily reduced its capacity charge at a time when KPLC was operating in the red, due in part to a drought-related recession, to show its support for the country and signal its interest in a second contract. Iberafrica later secured a second contract, albeit after even further reductions were negotiated and passed by the electricity regulator.[53]

For Rabai, in December 2007, following the elections, the project sponsors witnessed country-wide protests, which largely stalled financial closure. Sponsors chose, however, to continue work on the project, including on the environmental impact assessments so that the project would not lose too much time/momentum (Aldwych International, per com, 2010a).

A final area which may yield greater balancing in terms of development and investment outcomes is in the refinancing of projects, evidence for which may be seen in Songas which refinanced the second phase of the plant. Possible refinancing in the case of IPTL, with the Government of Tanzania proposing to buy the outstanding debt, could also lead to what may be perceived as more balanced outcomes. If and when the government buys back IPTL, it will make a once-off payment on behalf of the utility and then pass the asset ownership to TANESCO, which may subsequently decide to convert the plant to run on natural gas (although due to present capacity, as of 2011, this is unlikely for the next 3 years). Through this transaction, the capacity charge will be reduced to a token amount, and following conversion to gas, the energy charge dropped from US$9-12 m. to US$1-1.5 m. per month. The PPA will be terminated, a new agreement drafted, and the customers will see discounted tariffs.

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[53] It should, however, be noted that the fact that Iberafrica was not project-financed meant that the company was freer to change the payment streams.

Refinancing does, however, have only limited application, and must be dealt with carefully during the project negotiation, for, as one banker candidly indicated: "if project finance bankers are expected to finance projects with the understanding that periodically it will be necessary to have a restructuring, the outcome of which is uncertain, the result will be to eliminate the availability of non-recourse financing" – which, given the already low levels in Africa, should be avoided.

It is the government's willingness to share risks over the life of the project, which may also be pivotal in the long-term sustainability of projects. Strategic management does not occur in a vacuum, with the sponsor alone. Often the host country government may not only be an active counterparty, but even, as evidenced in the refinancing of IPTL, initiate such strategic management. Other government-led initiatives include the Government of Tanzania's buying down of Songas' AFUDC.

The myriad project-level factors are summarised in Table 8.

Table 8: Contributing elements to successful IPP investments, project issues

CES	Details
Favourable equity partners	-Local capital/partner contribution, where possible -Firms with development origins -Risk appetite for project -Experience with developing country project risk -Involvement of a DFI partner (and/or host country government) -Reasonable, fair ROE
Favourable debt arrangements	-Competitively priced financing, involvement of DFIs -Local capital/markets mitigate foreign exchange risk -Some flexibility in terms and conditions (possible refinancing)
Secure and adequate revenue stream	-Commercially sound metering, billing and collections by the utility (including the ability to disconnect customers who default on payments, be they Government ministries/departments or parastatals) -Generally, investors/financiers prefer markets where the off-taker is not a vertically integrated utility with own generation stations -Robust PPA (stipulates capacity and energy charges as well as dispatch, fuel metering, interconnection, insurance, *force majeure*, transfer, termination, change of law provisions, refinancing arrangements, dispute resolution, etc.)

Credit enhancements and security arrangements	Guarantees: Sovereign guarantees (offered and upheld), Partial risk guarantees, all of which should be made clear at the time of the tender Insurance: Political risk insurance Cash: escrow accounts, letters of credit, liquidity facilities
Positive technical Performance	-Technical performance high (including availability) -Sponsors anticipate potential conflicts (especially related to O&M, and budgeting) and mitigate them
Strategic management and relationship building	Sponsors work to create good image in country through political relationships, development funds, effective communications and strategically manage their contracts, particularly in the face of exogenous shocks and other stresses

4 Conclusion

Despite numerous challenges, a number of Sub-Saharan countries have managed to attract and sustain private investments in Independent Power Projects. More than 20 large IPPs have taken root in about eight countries. A number of smaller, private projects have also been developed. While some IPPs have encountered some contract changes, nearly all have survived and are countributing to social and economic development.We have identified the main contributing elements of success. At the country-level, factors such as favourable investment climates, clear policy and regulatory frameworks and the local availability of cost-competitive fuels, clearly help. Of growing importance are effective planning, procurement and contracting policies and practices. Kenya provides an example of how responsibilty for these functions may be allocated and institutionalised.

Although the evidence is not conclusive, strategic management on behalf of sponsors and government, as well as strong technical performance, have been used to strengthen projects. The role of firms with development origins such as Aldwych, Globeleq and IPS, and DFIs, such as IFC, PROPARCO, FMO and DEG, is increasingly important in the development and bringing to financial closure of new IPPs in Sub-Saharan Africa. Furthermore, the fact that projects with participation of these firms and DFIs were less likely to unravel signals two points: such projects may have been more balanced from the outset, and when an exogenous stress struck, they may also have been better equipped to resist any form of host country government pressure.

Some final observations may be made. First, there is evidence for contract unravelling across the pool of African IPPs where an imbalance is perceived between development and investment outcomes. Secondly, the incidence of such unravelling does not necessarily signal the end of a project's operation. New agreements may be reached that prove sustainable. Third, efforts must continue to close the initial gap between investors and host country governments' perceptions and treatment of risks (or else examples of further contract unravelling will continue). Finally, the means of closing the gap may

not be only, or mainly, via increasing the sort of new protections, including PRGs or political risk insurance, and may instead lie in systematic treatment of the numerous contributing elements to success defined by this report.

5 Recommendations

Country-level factors
Striking a balance between development and investment outcomes is among the main means to ensuring long-term sustainability for IPPs. How do we achieve such a balance? In our opinion, there are two different levels at which stakeholders need to address issues: the country level and project level. At the country level there are five major areas that help to facilitate balanced outcomes, namely: 1) a favourable investment climate; 2) a clear policy framework; 3) clear, consistent and fair regulatory oversight; 4) coherent power sector planning linked to procurement and contracting; 5) abundant low cost fuel and secure fuel contracts. Each of these areas are detailed below.

A favourable investment climate is characterized largely by the following: stable macro-economic policies; a legal and political system that allows contracts to be enforced and laws to be upheld; good repayment record and investment grade rating; less (costly) risk mitigation techniques to be employed which translates into lower cost of capital and hence lower project costs and more competitive prices; potentially more than one investment opportunity.

Another key ingredient at the country level is a ***clear policy framework***, which involves: a policy framework enshrined in legislation, that clearly specifies market structure and roles as well as terms for private and public sector investments (generally for single buyer model, not, yet, wholesale competition in the African context); in addition, reform-minded 'champions', concerned with long-run, lead and implement framework.

Clear, consistent and fair regulatory oversight is pivotal for balanced outcomes as it improves general performance of private and public sector assets. Important components include: the perceived independence of the regulator; transparent and predictable licensing and tariff framework, which improves investor confidence; cost-reflective tariffs to ensure revenue sufficiency, where possible, as well as targeted subsidies, where necessary; and finally the general 'protection' of consumers.

Often overlooked but among the most critical areas is ***coherent power sector planning linked to procurement and contracting***. Specifically, an energy security standard is in place, and planning roles and functions are clarified; power planning is vested with lead, appropriate (skilled, resourced and empowered) agency, and power sector planning takes into consideration the hybrid market (public and private stakeholders and their respective real costs of capital) and fairly allocates new build opportunities among stakeholders. In addition, planning has built-in contingencies to avoid emergency power plants or blackouts; responsibility for procurement is clearly allocated, plans are linked to procurement and bids are initiated in time; pre-tender technical and environmental due-diligence on the proposed site is also essential, and the procurement process is transparent and, provided numerous bids received, competition ultimately drives down prices. Finally, capacity is built to contract, tender and evaluate effectively.

A final area at the country level which may make or break the long-term sustainability of

projects is: ***abundant, low cost fuel and secure contracts***. For this to make sense, chosen fuel must be cost-competitive with other fuels, and contracts safeguard affordable and reliable fuel supply for the duration of the project.

Project-level factors

In addition to the abovementioned areas, there are a suite of factors relevant directly to the project that may help facilitate more balanced outcomes, namely: 1) favourable equity partners; 2) favourable debt arrangements; 3) a secure and adequate revenue stream; 4) credit enhancements and security arrangements; 5) positive technical performance and finally, 6) strategic management and relationship building. Each of these factors are elaborated below.

Favourable equity partners is defined as follows: where possible, the involvement of local partners and equity as well as firms with development origins; appetite for the actual project risk and specific experience with developing country project risk; the involvement of a DFI partner and/or a host country government; a return on equity that is generally perceived by parties as a reasonable and fair.

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Favourable debt arrangements are paramount for the long-term sustainability of projects and may be characterized as follows: competitively priced financing, including possibly the involvement of DFIs; local capital markets, which have the potential to mitigate foreign exchange risk; some flexibility in terms and conditions (including possible refinancing).

Of utmost importance is a ***secure and adequate revenue stream***, which is generally made possible via the following conditions: commercially sound metering, billing and collections by the utility (including the ability to disconnect customers who default on payments, be they Government ministries/departments or parastatals); it should be noted that investors/financiers prefer markets where the off-taker is not a vertically integrated utility with own generation stations; the revenue stream should be safeguarded in a robust PPA, which stipulates capacity and energy charges as well as dispatch, fuel metering, interconnection, insurance, *force majeure*, transfer, termination, change of law provisions, refinancing arrangements, dispute resolution, etc.

Taking various forms, ***credit enhancements and security arrangements*** are part of the muscle that attracts and sustains IPPs, specifically: sovereign guarantees, partial risk guarantees; political risk insurance and cash, namely escrow accounts, letters of credit and liquidity facilities--all of which should be made clear at the time of the tender, especially the sovereign guarantees which are cited as among the most effective instrument when coupled with a PRG.

Positive technical performance is an area where most IPPs have a clear advantage, however, it should not be taken for granted; this encompasses high technical performance, including availability, and also that sponsors anticipate potential conflicts (especially related to O&M, and budgeting) and mitigate them.

Strategic management and relationship building is grease for the wheels and an integral part of the balancing of development and investment outcomes. Sponsors should work to create a positive image through political relationships, development funds, and effective communications. Ongoing, strategic management of their contracts, especially in the face of exogenous stresses, is critical.

Appendix A: Project Specifications

Detailed specifications are presented for each IPP discussed in this paper.

Cameroon (1 of 2)

Project	Dibamba
Size	88MW
Cost	US$126 million
$ per kW	US$1431/kW
Fuel/Technology	HFO/peaking plant
ICB	No, direct negotiation
Contract	BOT, 20 yrs (2029)
Debt/Equity	75/25
DFI in equity and debt	Yes (debt)
Local participation in equity and debt	Yes (equity)
Equity partners (country of origin & % of each shareholder)	AES (USA, 56%), Republic of Cameroon (44%)
Lenders	IFC, AfDB, FMO
Credit enhancements and security arrangements	Typical project finance security agreements have been implemented, but details have not been made public
Project tender, COD	November 2009
Contract change	Changes have occurred in the Tolling Agreement between the first draft and the final executed document, due to changes in financial and construction cost assumptions. Note that the Tolling Agreement was signed after the plant was commissioned.
Fuel arrangement	HFO / Tolling agreement with AES Sonel as Toller

Cameroon (2 of 2)

Project	Kribi Power Plant
Size	216MW (possibly 195MW due to gas quality)
Cost	US$342 million
$ per kW	US$1583/kW
Fuel/Technology	Natural gas
ICB	Yes
Contract	BOT, 20 yrs (2032)
Debt/Equity	75/25
DFI in equity and debt	Yes (debt)
Local participation in equity and debt	Yes (debt)
Equity partners (country of origin & % of each shareholder)	AES (USA, 56%), Republic of Cameroon (44%)
Lenders	IFC, AfDB, EIB, BDEAC, FMO, PROPARCO, BIRD (PRG + local banks, with debt, including local debt portion still under negotiation)
Credit enhancements and security arrangements	PRG
Project tender, COD	2012 (expected)
Contract change	The draft PPA is evolving, as the commercial, technical and financial assumptions evolve, however, no further information is presently available.
Fuel arrangement	A gas supply agreement has been signed with a state-owned gas supplier.

Cote d'Ivoire (1 of 2)

Project	Compagnie Ivoirienne de Production d'Electricité (CIPREL)
Size	210 MW
Cost	US$105.6 million[54]
$ per kW	US$503
Fuel/Technology	Natural gas/open cycle
ICB	None
Contract	BOOT, 19 years
Debt/Equity	-
DFI in equity and debt	Yes (equity and debt)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	SAUR International, with 88% (JV between French SAUR Group owned by Bouygues, 65% and EDF, 35%) BOAD, PROPARCO, and IFC holding the remaining 12%; in 2005 all shares sold to Bouygues (France, 98%), except BOAD (2%)
Lenders	World Bank
Credit enhancements and security arrangements	None
Project tender, COD	1993, 1995
Contract change	None
Fuel arrangement	Government procures fuel

[54] Investment cost €87.8m or 57.6 billion CFA, with the average 1994 conversion of US$ to CFA, 545.100.

Cote d'Ivoire (2 of 2)

Project	Azito
Size	288 MW[55]
Cost	US$225 million
$ per kW	US$781
Fuel/Technology	Natural gas/open cycle
ICB	Yes
Contract	BOOT, 24 years
Debt/Equity	70/30
DFI in equity and debt	Yes (debt)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	Cinergy (JV between Swiss ABB, 50% and French EDF, 50%) Holds 65.7% of shares, CDC/Globeleq (11%), and IPS (23%)
Lenders	IFC, CDC, FMO, DEG, AfDB, Societe Generale and other European commercial banks
Credit enhancements	World Bank partial risk guarantee Sovereign guarantee
Security arrangements	Escrow account equivalent to 1 month capacity charge
Project tender, COD	1996, 2000
Contract change	None
Fuel arrangement	Government procures fuel

[55] The initial project concept included specifications to raise capacity to 420 MW.

Ghana (1 of 2)

Project	Takoradi II
Size	220 MW[56]
Cost	US$110 million
$ per kW	US$500
Fuel/Technology	Light crude oil/single cycle
ICB	None
Contract	BOOT, 25 years
Debt/Equity	Financed exclusively with balance sheet of sponsors
DFI in equity and debt	No
Local participation in equity and debt	Yes (equity)
Equity partners (country of origin & % of each shareholder)	CMS (USA, 90%), VRA (Ghana, 10%), CMS sold shares to TAQA (UAE, 90%) in 2007
Lenders	Financed exclusively with balance sheet of sponsors
Credit enhancements	Sovereign guarantee
Security arrangements	US$ 3 million Letter of Credit provided by government
Project tender, COD	1998, 2000
Contract change	Failure to develop 2nd phase (110 MW), investors cited the lack of government guarantees (granted in the first phase of Takoradi II) meanwhile government indicated that the EPC costs were too high; until recently, further development remained at standstill, however the past year (2011) has seen some activity including a proposal to IFC for up to US$70m. of a total estimated project cost of US$325m.
Fuel arrangement	Government procures fuel

[56] The initial project concept included specifications to add a second phase of 110 MW and convert to combined cycle, however, lack of funding has limited the completion of this phase, until recently.

Ghana (2 of 2)

Project	Sunon Asogli Power Plant
Size	200MW
Cost	NA
$ per kW	NA
Fuel/Technology	Combustion engine
ICB	No
Contract	BOO, 20 years
Debt/Equity	NA
DFI in equity and debt	None
Local participation in equity and debt	Local strategic investor, Togbe Afede XIV
Equity partners (country of origin & % of each shareholder)	Shenzhen (China, 100%)
Lenders	NA
Credit enhancements and security arrangements	NA
Project tender, COD	2011
Contract change	Related to fuel
Fuel arrangement	Interim fuel agreement for access to WAGP gas

Kenya (1 of 5 projects)

Project	Westmont
Size	46 MW
Cost	US$65 million
$ per kW	US$1413
Fuel/Technology	Kerosene/gas condensate/gas turbine (barge mounted)
ICB	None, but selective international tender conducted
Contract	BOO, 7 years
Debt/Equity	NA
DFI in equity and debt	None
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	Westmont (Malaysia, 100%) has sought to sell plant since 2004
Lenders	NA
Credit enhancements & security arrangements	None
Project tender, COD	1996, 1997
Contract change	Not a contract change per se, but firm failed to negotiate a second contract after its 7 year contract ended in 2004 due to failure to agree on tariffs
Fuel arrangement	Originally Westmont to procure fuel and then pass through to utility, however, following dispute with fuel supplier about taxes after the first year of operation, utility took over procurement

Kenya (2 of 5 projects)

Project	Iberafrica
Size	108.3MW (44, 12, 52.3 brought on, respectively)
Cost	US$35 million (only for 1st 56MW)
$ per kW	NA
Fuel/Technology	HFO/medium speed diesel engine
ICB	None
Contract	BOO, 7 years, 15 years, 25 years
Debt/Equity	72/28
DFI in equity and debt	None
Local participation in equity and debt	Yes (equity and debt)
Equity partners (country of origin & % of each shareholder)	Union Fenosa (Spain, 80%), KPLC Pension Fund (Kenya, 20%) since 1997
Lenders	Union Fenosa (US$12.7 million in direct loans and guaranteed US$20 million); KPLC Staff Pension Fund (US$9.4 in direct loans and guaranteed US$5 million through a local Kenyan bank).
Credit enhancements and security arrangements	None
Project tender, COD	1996, 1997/1999, 2000/2008,2009
Contract change	Yes, Iberafrica reduced the capacity charge of its first PPA by 37 percent in April 2002 and then to 59 percent of the original PPA in September 2003.[57]
Fuel arrangement	Iberafrica buys fuel and passes cost through to KPLC based on the units generated and specific consumption parameters agreed on in the PPA

[57] Furthermore, although not a contract change per se, the value of the capacity charge for Iberafrica's second PPA was 50 percent that of the first PPA.

Kenya (3 of 5 projects)

Project	OrPower4
Size	13 MW + 35MW
Cost	105[58]
$ per kW	NA
Fuel/Technology	Geothermal
ICB	Yes
Contract	BOO, 20 years
Debt/Equity	NA
DFI in equity and debt	DEG
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	Ormat (100%) since 1998 - UNTIL 2008
Lenders	NA
Credit enhancements and security arrangements	MIGA guarantee, a stand-by Letter of Credit, covering several months billing (although only finalized at end-2006)
Project tender, COD	1996, 2000 – 2009
Contract change	Yes, tariff for the second phased (35 MW) reduced
Fuel arrangement	The only fuel arrangement per se is that OrPower4 was granted a Geothermal Resource License from the government, to which it pays a royalty of sorts (of US$0.004/kWh or USc 0.4/kWh)

[58] US$105 includes only the loan portion for the 35MW part of the plant (Ormat, per com, 2010).

Kenya (4 of 5 projects)

Project	Tsavo
Size	75 MW
Cost	US$86 million
$ per kW	US$1,133
Fuel/Technology	HFO/medium speed diesel engine
ICB	Yes
Contract	BOO, 20 years
Debt/Equity	78/22
DFI in equity and debt	Yes (equity and debt)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	Cinergy & IPS jointly owned 49. 9%, Cinergy sold to Duke Energy in 2005, CDC/Globeleq (UK, 30%), Wartsila (Finland, 15%), IFC (5%) retain remaining shares since 2000
Lenders	IFC own account (US$16.5 million), IFC syndicated (US$23.5 million); CDC own account (US$13 million); DEG own account (€11 million), DEG syndicated (€2 million)
Credit enhancements and security arrangements	Letter of Comfort provided by government, and escrow account, equivalent to 1 month capacity charge, and a stand-by Letter of Credit, equivalent to 3 months billing
Project tender, COD	1995, 2001
Contract change	None, but was pressured to lower tariff
Fuel arrangement	Tsavo buys fuel and passes cost through to KPLC based on the units generated and specific consumption parameters agreed on in the PPA

Kenya (5 of 5 projects)

Project	Rabai
Size	90MW
Cost	US$155 million
$ per kW	US$1,722
Fuel/Technology	HFO
ICB	Yes
Contract	BOOT, 20 years
Debt/Equity	75 Debt, 5% Subordinated Debt, 25% Equity
DFI in equity and debt	Yes
Local participation in equity and debt	No
Equity partners (country headquarters & % of each)	Aldywch: 34.%, BWSC (Danish, but owned by Mitsui of Japan): 25.5%, FMO: 20%, IFU (Danish bilateral lender): 20%
Lenders	DEG: 15%, FMO: 25%, EAIF: 25%, Proparco: 25%, EFP (European Financing Partners): 10%
Credit enhancements and security arrangements	Support Letter from GoK (covers political risk but falls short of being an outright guarantee), and KPLC issued a letter of credit equivalent to 5 months of capacity (debt service, fixed costs and equity returns) payments and 2 months of fuel payments
Project tender, COD	2006, 2009
Contract change	None
Fuel arrangement	Fuel Supply Agreement with Kenol of Kenya

Nigeria (1 of 3)

Project	AES Barge Limited
Size	270 MW
Cost	US$240 million
$ per kW	US$888
Fuel/Technology	Natural gas/open cycle (barge mounted)
ICB	None
Contract	BOO, 13 years
Debt/Equity	NA
DFI in equity and debt	None
Local participation in equity and debt	Yes (equity)
Equity partners (country of origin & % of each shareholder)	Enron (USA, 100%) sold to AES (95%) and YFP (Nigeria, 5%) in 2000
Lenders	NA
Credit enhancements and security arrangements	OPIC political risk insurance Sovereign guarantee, US$60 million Letter of Credit from Ministry of Finance
Project tender, COD	1999, 2001
Contract change	Yes, initial plant size increased from 90 MW to 270 MW (9 units of 30 MW each) and change in the fuel from liquid fuel to natural gas, both of which had the effect of reducing the capacity charge; recent arbitration (lasting 5 years) concluded, involving among other things the availability deficiency payment, meanwhile tax exemption certificate has been withheld by government for the duration of the project
Fuel arrangement	Utility arranges fuel

Nigeria (2 of 3)

Project	Okpai
Size	450 MW
Cost	US$ 462[59]
$ per kW	
Fuel/Technology	Natural gas/combined cycle
ICB	None
Contract	BOO, 20 years
Debt/Equity	100% equity financed
DFI in equity and debt	None
Local participation in equity and debt	Yes (equity and debt)
Equity partners (country of origin & % of each shareholder)	Nigerian National Petroleum Corporation (Nigeria, 60%), Nigerian Agip Oil Company (Italy, 20%), and Phillips Oil Company (USA, 20%) maintained equity since 2001
Lenders	Provided by equity partners
Credit enhancements and security arrangements	PPA backed by Nigerian Petroleum Development Company's oil revenues
Project tender, COD	2001, 2005
Contract change	Ongoing negotiations related to investment costs which rose by US$150 million, to US$462 million; although plant is producing power, due to the dispute, full payment is not being made by utility
Fuel arrangement	Project company provides fuel

[59] Project costs include the gas infrastructure.

Nigeria (3 of 3)

Project	Afam VI
Size	630MW
Cost	NA
$ per kW	NA
Fuel/Technology	CCGT
ICB	No
Contract	BOO, 20 years
Debt/Equity	100% equity
DFI in equity and debt	None
Local participation in equity and debt	Yes, NNPC
Equity partners (country of origin & % of each shareholder)	NNPC (Nigeria, 55%), Shell (UK/Netherlands, 30%), Elf (Total) (France, 10%), Agip (Italy, 5%)
Lenders	
Credit enhancements and security arrangements	PPA backed by Nigerian Petroleum Development Company's oil revenues
Project tender, COD	2000, 2008
Contract change	No
Fuel arrangement	Project company provides fuel

Senegal (1 of 2)

Project	GTi Dakar
Size	52MW
Cost	US$65 million
$ per kW	US$1250/kW
Fuel/Technology	Complete cycle/Diesel/natfa
ICB	Yes
Contract	BOOT, 15 years
Debt/Equity	75/25
DFI in equity and debt	Yes (both)
Local participation in equity and debt	None
Equity partners (country of origin & % of each shareholder)	GE Capital Structured Finance Group (SFG) (USA), IFC, Edison (Italy)
Lenders	IFC and Credit Commercial de France (CCF)
Credit enhancements and security arrangements	Government guarantee, credit insurance through a guarantee program of SACE, the Italian export credit agency, and a partial interest subsidy through the Mediocredito Central Subsidy Department (MCSD), escrow account
Project tender, COD	1996, 1999/2000
Contract change	None
Fuel arrangement	-

Senegal (2 of 2)

Project	Kounoune I
Size	68MW
Cost	US$110 million
$ per kW	US$1617/kW
Fuel/Technology	HFO diesel
ICB	Yes
Contract	BOO, 15 years
Debt/Equity	-
DFI in equity and debt	Yes (debt)
Local participation in equity and debt	Yes (debt)
Equity partners (country of origin & % of each shareholder)	Mitsubishi (Japan), Matelec S.A.L (Lebanon)
Lenders	IFC, Proparco, AfDB, BOAD and CBAO
Credit enhancements and security arrangements	Government Guarantee, a PRG although the latter was never signed by the government, a letter of credit from Senelec
Project tender, COD	2003, 2008
Contract change	None
Fuel arrangement	During the project negotiations, the structure of the FSA and PPA were changed to turn the PPA into a tolling agreement.

South Africa (1 of 1)

Project	Sasol
Size	240 MW + 80 MW
Cost	R1.5 billion + R1 billion
$ per kW	830 + 1600
Fuel/Technology	OCGT + CCGT
ICB	No
Contract	MTPPP till March 2015
Debt/Equity	Financed off Sasol balance sheet
DFI in equity and debt	No
Local participation in equity and debt	Sasol
Equity partners (country of origin & % of each shareholder)	Sasol
Lenders	Financed off Sasol balance sheet
Credit enhancements and security arrangements	None
Project tender, COD	2010
Contract change	No
Fuel arrangement	Natural gas from Mozambique shifting to methane rich process gas

Tanzania (1 of 2 projects)

Project	IPTL
Size	100 MW
Cost	US$120 million
$ per kW	US$1,200
Fuel/Technology	HFO/medium speed diesel engine
ICB	None
Contract	BOO, 20 years
Debt/Equity	70/30 (albeit debt equity ratio disputed)
DFI in equity and debt	None
Local participation in equity and debt	Yes (in kind equity participation)
Equity partners (country of origin & % of each shareholder)	Mechmar (Malaysia, 70%), VIP (Tanzania, 30% **in kind**), both have sought to sell shares
Lenders	Two Malaysian-based banks (Bank Bumiputra Malaysia Berhad--now Bank Bumiputra Commercial Bank--and SIME Bank) auctioned debt to Standard Chartered Bank
Credit enhancements and security arrangements	Sovereign guarantee, liquidity facility equivalent to 4 months capacity charge (but not yet established)
Project tender, COD	1997, 2002
Contract change	Yes, post arbitration, monthly capacity charges lowered from US$3.6 million to US$2.6 million
Fuel arrangement	IPTL imports fuel, which is a pass through to the utility

Tanzania (2 of 2 projects)

Project	Songas
Size	180 MW[60]
Cost	US$316 million[61]
$ per kW	US$2,313 (for first 115 MW) and US$769 (for 65 MW expansion)
Fuel/Technology	Natural gas/open cycle
ICB	Yes
Contract	BOO, 20 years
Debt/Equity	70/30 for 115 MW 100% equity financed for 65MW expansion, which has since been refinanced
DFI in equity and debt	Yes
Local participation in equity and debt	Yes (TANESCO, TDFL)
Equity partners (country of origin & % of each shareholder)	TransCanada sold majority shares to AES (USA) in 1999 and AES sold majority shares to Globeleq (UK) in 2003[62]. All preferred equity shares were converted into "Loan Notes" in June 2009. Only common share remain.
Lenders	World Bank (US$136 million), EIB, (US$55 million), Sida, (US$15 million)
Credit enhancements and security	Escrow account: for first 115 MW, with the government matching every US$1 spent by the project company; liquidity facility equivalent to 4

[60]There was considerable evolution in terms of the planned capacity for the plant, from 60 MW to the current 180 MW.

[61]Songas project costs include refurbishment of gas wells, a new gas processing facility, pipeline construction and fuel conversion of the existing power station (Ubungo), in total amounting to US$266 million, and an additional US$50 million for expansion in terms of two additional turbines (total 65 MW) and related infrastructure. The expansion was financed entirely by equity. A rough estimate for the electricity generation component would be 40 percent of project costs or US$130 million, based on US$35 million for refurbishment and fuel conversion of existing turbines, US$45 million assumed loans on existing turbines, and US$50 million for expansion.

[62] Due to complexity, turnover is detailed in this footnote: Ocelot (Canada), TransCanada (Canada), Tanzania Petroleum Development Corporation, TPDC (Tanzania), TANESCO (Tanzania), Tanzania Development Finance Company, TDFL (Tanzania, sponsored by EIB), IFC (multilateral), DEG (German), CDC (UK) were shareholders by 1996, with TransCanada the majority shareholder; IFC and DEG sold shares to CDC in 1997/8; TransCanada sold shares to AES (USA) in 1999; Ocelot/PanOcean sold shares to AES in 2001; AES sold majority shares to Globeleq (UK) and FMO (Holland) in 2003. After the AES sale, equity shares and associated financial commitments (expressed in US$ million) in Songas were as follows: Globeleq: US$33.8 (56%); FMO: US$14.6 (24%); TDFL: US$4 (7%); CDC: US$3.6 (6%); TPDC: US$3 (5%) and TANESCO: US$1 (2%). This does not reflect the additional US$50 million that Globeleq committed for the expansion

arrangements	months capacity charge for the first 3 years, declining to 2 months starting in year 4 through the remaining years of the contract
Project tender, COD	1994, 2004
Contract change	The changes to Songas' PPA include: (1) US$103 m. AFUDC buy-down; (2) the use of escrow funds to buy down the AFUDC; (3) freezing the liquidity facility, which was meant to be replenished and be accessed only in the case of partial or non-payment by TANESCO; and (4) preferred equity conversion to "loan notes"
Fuel arrangement	Songo Songo gas provided to project company at a rate of US$0.55/MMBtu for turbines I-V and at US$2.17 MMBtu for turbine VI

Togo (1 of 1)

Project	Extension of Central Thermique de Lome (CTL) [63]
Size	100MW
Cost	US$196 million (including 18 km transmission lines rehabilitation and soil decontamination investment)
$ per kW	US$1,960
Fuel/Technology	Triple fuel
ICB	No
Contract	BOOT, 25 years
Debt/Equity	75/25
DFI in equity and debt	Yes (debt)
Local participation in equity and debt	None (but contract stipulates up to 25% of equity must be sold to local/Togolese)
Equity partners (country of origin & % of each shareholder)	Contour Global (USA, 80%), IFC (20%)
Lenders	OPIC
Credit enhancements and security arrangements	Government guarantee, OPIC guarantee, escrow account for one month of full operation, letter of credit of 2 months of full operation, (which become one month after 2 years of no incident of payment, and ceases to exist after 4 years of no incident)
Project tender, COD	Online as of October 2010
Contract change	No
Fuel arrangement	The buyer (utility provides fuel)

[63] CTL was a pre-existing 90MW facility for which a Rehabilitate Own Transfer (ROT) contract was provided to Electro Togo in 2001 to undertake/manage. In 2006, however, when a power crisis intensified and the rehabilitation had not yet been completed, the Government of Togo opted to terminate the ROT via Electro Togo and initiate a BOOT directly with Contour Global, which had previously been involved in discussions with ElectroTogo (Ministry of Energy of Togo, per com, 2010).

Uganda (1 of 2)

Project	Namanve Power Plant/Jacobsen Uganda Power Plant Limited
Size	50MW
Cost	US$74 million at inception
$ per kW	US$1488/kW
Fuel/Technology	HFO
ICB	Yes
Contract	BOOT, 6 year
Debt/Equity	-
DFI in equity and debt	Yes (debt)
Local participation in equity and debt	Yes (debt)
Equity partners (country headquarters & % of each)	Jacobsen Elektro (100% / Norway)
Lenders	Loan from Standard Chartered Bank UK, partly guaranteed by GIEK (the Norwegian guarantee agency), commercial loan from Stanbic Bank (U) Ltd (back-stopped by Standard Chartered Bank UK); subordinate loan from parent company Jacobsen Elektro AS; NORAD grant
Credit enhancements and security arrangements	GIEK guarantee backed up by Government of Uganda
Project tender, COD	COD 2008
Contract change	None
Fuel arrangement	Openly bid for contract – not part of license – (plant availability should be >90%)

Uganda (2 of 2)

Project	Bujagali
Size	250MW
Cost	US$860 million
$ per kW	US$3,440
Fuel/Technology	Hydro
ICB	Yes
Contract	BOT, 30 years
Debt/Equity	78/22
DFI in equity and debt	Debt
Local participation in equity and debt	Yes, Government of Uganda
Equity partners (country headquarters & % of each)	Sithe Global (58%), IPS/Aga Khan (32% but 50.1% voting), Government of Uganda (10%)
Lenders	African Development Bank, EIB, PROPARCO, AFD, DEG, KfW, FMO and IFC as DFIs, NedBank, Absa Capital, Standard Chartered Bank and Fortis as commercial banks covered by the PRG
Credit enhancements and security arrangements	Government Guarantee, MIGA, PRG/ IDA
Project tender, COD	2005, expected 2011/12
Contract change	None
Fuel arrangement	NA

Zambia (1 of 1)

Project	Itezhi-tezhi
Was the project in the National Energy Plan?	Yes
Size	120 MW
Cost	US$230 million
Fuel/Technology	Hydro
ICB	
Contract	BOOT, 25 years
Debt/Equity	70/30
DFI in equity and debt	-
Local participation in equity and debt	Yes
Equity partners (country of origin & % of each shareholder)	Tata, (India, 50%), Zesco (Zambia, 50%)
Lenders	-
Credit enhancements and security arrangements	3 month escrow account
Project tender, COD	COD: 48 months from 2012
Contract changes to date?	None
Fuel arrangement	Itezhi Tezhi Dam on the Kafue River

Appendix B: Large-scale IPPs seeking financial closure

Country/ Project	Size (MW)	Fin. Close expected	Fuel/cycle
Ghana			
Takoradi II (second phase)	110		gas/LCO CCGT
Kpone	340		CCGT
Kenya			
Triumph (Athi River)	81	4Q11-2Q12	medium speed, diesel, HFO-fired
Gulf Power (Athi River)	84	4Q11-2Q12	medium speed, diesel, HFO-fired
Melec (Thika)	87	4Q11-2Q12	medium speed, diesel, HFO-fired
Lake Turkana (Loiyangalani)	300	4Q11-2Q12	Wind
Aeolus Kenya Limited'	60	4Q11-2Q12	Wind
Addition to OrPower4	52	4Q2011	Geothermal
Nigeria			
Notore Power Ltd	50		*All projects presently operational (supplying designated customers), once Bulk Trader is operational, expected to supply excess power to grid*
Paras Energy	96		
DIL Power Plc	135		
Eleme Petrochemical Co	135		
South Africa			
Suez peaker plant (Avon)	670		OCGT
Suez peaker plant (Dedisa)	335		OCGT
Tanzania			
Information forthcoming			
Uganda			
Karuma	600		Hydro
Zambia			
Kafue Gorge	750		Hydro
Maamba Collieries	300		Coal
Ndola Energy	50		HFO

Appendix C: Small IPPs in SSA <40 MW

+ Mauritius (CoGens), & South Africa (MTPPPs)

Country	Name of project	MW	Status	Fin. close	Tech/fuel
Angola	Chicapa Hydroelectric Plant	16	Operational	2003	Hydro
Burkina Faso	Hydro-Afrique Hydroelectric Plant	12	Operational	1998	Hydro
Ghana	Genser (5 +25+30)	60 combined	Operational		
Kenya	Mumias Power Plant	35	Operational	2008	Cogen
Madagascar	Hydelec Madagascar (100% / Madagascar)	15	Operational	2007	Hydro
Mauritius	FUEL power plant	40	Operational	1998	Cogen
Mauritius	St. Aubin Power Project	34	Operational	2004	Cogen
Mauritius	Deep River Beau Champ	29	Operational	1997	Cogen
Rwanda	Kivuwatt (Contour Global)	25	Construction	2011	Methane /gas
S. Africa	Sappi	35	Operational	2010	Cogen
S. Africa	IPSA	13	Operational	2011	Cogen
S. Africa	TSB Sugar	2.6	Operational		Cogen
S. Africa	Bethlehem Hydro	4	Operational	2005	Hydro
S. Africa	Darling Wind Farm	5	Operational	2006	Wind
Tanzania	Mtwara Region Gas-to-Power Project	12	Operational	2005	Natgas
Uganda	Electromaxx*	20	Operational	-	HFO
Uganda	Kasese Cobalt Company Ltd (KCCL)	10	Operational	-	Hydro
Uganda	Bugoye/Tronder Hydro Electric Power Project	13	Operational	2008	Hydro
Uganda	Kakira Sugar Ltd	12	Operational	2008	Cogen
Uganda	Kinyara Sugar Ltd	5	Operational	2009	Cogen
Uganda	Kilembe Mines Ltd (KML)	5	Operational	-	Hydro
Uganda	West Nile Rural Electrification (WENRECo)	1	Operation	2005	HFO
Uganda	Mpanga Hydro Power Project	18	Construction	2008	Hydro
Uganda	Ishasha	5	Construction	-	Hydro
Uganda	Buseruka/Hydromax	10	Construction	-	Hydro
Uganda	Nyagak	3.5	Construction		Hydro
Zambia	Kabompo Gorge Hydro Project	34	Construction		Hydro

Note: in addition Mauritius' Belle Vue Power Plant is operational, a 100MW cogen plant that reached financial closure in 1998. It is not included in the above tally due to its size.

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