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An Analysis of Independent Power Projects in Africa: Understanding Development and Investment Outcomes

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This study analyses the outcomes of African independent power projects (IPPs). Nearly 40 such projects have taken root to date, concentrated mainly in 8 countries. More balanced outcomes are perceived in North Africa than across sub-Saharan Africa (SSA), for reasons linked to more attractive investment environments, more robust policy frameworks, fewer planning mishaps, abundant low-cost fuel and secure fuel contracts as well as credit enhancements such as sovereign guarantees. With few exceptions, these elements were absent in SSA, where the role of development finance institutions and the strategic management of projects seem more important.

Key words: Independent power projects, IPP, power sector reform

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 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.[1] 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 (IPP), namely, privately

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1. 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, in the following order: 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 (Bacon, 1999: 4; 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.

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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 quick and relatively easy 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-led IPP to sell power to the grid under long-term contracts with the state utility. Egypt also became a magnet for private sector investment. Ghana, Kenya, Morocco, Tanzania and Tunisia, among others, also opened their doors to foreign and local investors. In 1997, later seen as the peak of investment, there was a record US$1.8 billion in IPPs in Africa (World Bank, 2006).

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.[2] 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 facilities, exposed countries to significant exchange-rate risks. Finally, while Africa has seen private participation in greenfield electricity projects continue, private investments have not achieved the levels of the late 1990s, with 1997 representing the zenith.

Several factors explain the recent trends in investment. Private-sector firms were deeply affected by the Asian and subsequent Latin American financial crises. 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. Furthermore, DFIs began to reconsider their position of restricted infrastructure investment, which had predominated throughout the 1990s. As concessionary funding became available again, many countries opted for publicly funded projects, rather than their private-sector counterpart; for instance, Egypt has seen its current five-year power investment implemented by the incumbent, state-owned utility, and supported entirely by concessionary loans.

Despite this revival of concessionary lending, investments are insufficient to address Africa's power needs, with only 25% of the population currently with electricity access, and poor supply the rule, not the exception. With the original drivers for market reform still present, private-sector involvement appears inevitable in the future.

2. Exceptions are Côte d'Ivoire, Morocco and Tanzania, where IPPs have contributed significantly (more than 50%) to overall electricity production.

Table 1: African IPP sample, general project specifications

Country/ project	Size (MW)	Cost (US$ m.)	Fuel/cycle	Contract		Project tender -COD
				Type	Years	
Egypt						
Sidi Krir	683	413.9	Natgas/steam cycle	BOOT	20	1996-2002
Port Said	683	340	Natgas/steam cycle	BOOT	20	1998-2002
Suez	683	338	Natgas/steam cycle	BOOT	20	1998-2003
Morocco						
Jorf Lasfar	680+680[a]	1500[b]	Coal	BTO	30	1994-2000
CED	50	58.5[c]	Wind	BTO	19	1995-2000
Tahaddart	384	364.9	Natgas/ combined cycle	BTO	20	1999-2005
Tunisia						
Rades II	471	260.7	Natgas/ combined cycle	BOO	20	1997-2002
SEEB	27	30[d]	Natgas/open cycle	BOO	20	2000-2003
Kenya						
Westmont	46	35	Kerosene/ gas condensate/ gas Turbine (barge-mounted)	BOO	7	1996-7
Iberafrica	56	65	HFO/medium speed diesel engine	BOO	7, 15	1996-7
OrPower4	13	54	Geothermal	BOO	20	1996-2000
Tsavo	75	85	HFO/medium speed diesel engine	BOO	20	1995-2001
Tanzania[e]						
IPTL	100	120	HFO/medium speed diesel engine	BOO	20	1997-8
Songas	180	316	Natgas/open cycle	BOO	20	1994-2004
Mtwara	12	8.2	Natgas/gas-fired reciprocating engine	BOO	2[f]	1994-2007
Côte d'Ivoire						
CIPREL	210	105.6[g]	Natgas/open cycle	BOOT	19	1993-5
Azito	330	233	Natgas/open cycle	BOOT	24	1996-2000
Ghana						
Takoradi II	220[h]	110	Light crude oil/single cycle	BOOT	25	1998-2000
Nigeria						
AES Barge	270	240	Natgas/open cycle (barge-mounted)	BOO	20 (2 parts)	1999-2001
Okpai	450	462	Natgas/ combined cycle	BOO	20	2001-2005

Notes: a) The first 680 MW refer to an existing facility; the greenfield investment was an additional 680 MW; b) includes upgrade of coal-receiving facility and transport infrastructure to ONE's Mohamedia plant; c) Euros at €45.7 m., converted to US$ on 24 August 2006 (€1 = $1.28); d) SEEB, Songas and Okpai include the gas infrastructure; e) Tanzania's Tanwat is a 2.5 MW facility, selling excess power into the grid and therefore is not included here; f) 20-year PPA may be signed with TANESCO; g) €87.8 m. or 57.6 bn CFA, 1994 US$/CFA conversion 545.100; h) initially included a second phase of 110 MW and conversion to combined cycle, halted due to lack of funding.
COD: commercial operation date; natgas: natural gas; BOOT: Build Own Operate Transfer; BTO: build, transfer, operate; BOO: Build Own Operate; HFO: heavy fuel oil.

This article[3] seeks to evaluate IPPs in Africa by focusing on development and investment outcomes, namely, the extent to which reliable and affordable power has been provided for the host country, and satisfactory returns on investments and new investment opportunities have been achieved. Case studies of eight African countries (Egypt, Tunisia, Morocco, Côte d'Ivoire, Ghana, Kenya, Tanzania and Nigeria), 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.

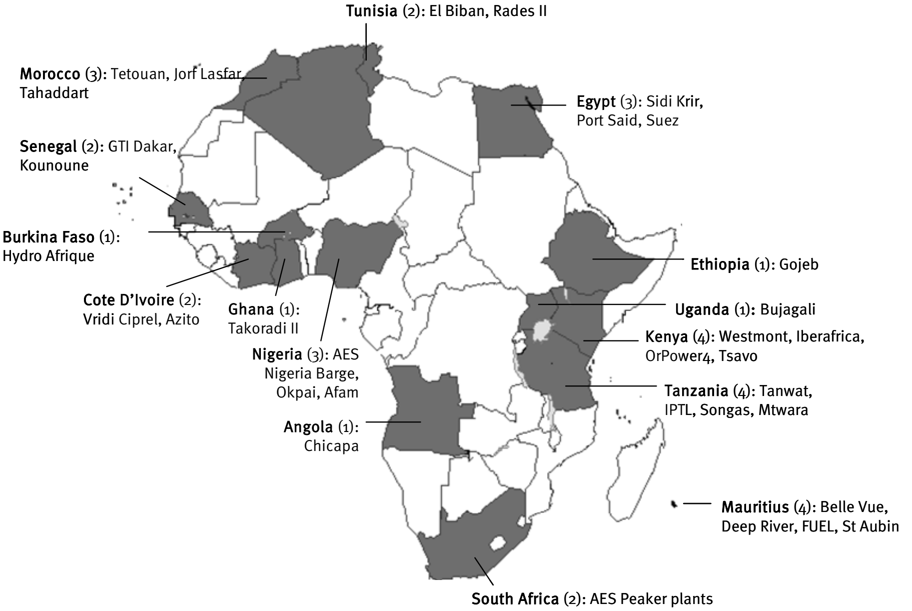
2 IPPs in Africa: an overview

Approximately 40 IPPs have been developed in Africa to date (see Figure 1). With few exceptions,[4] they represent only a fraction of total generation capacity and have mostly complemented incumbent state-owned utilities.[5]

Nevertheless, IPPs have been an important source of new investment in the power sector in about a dozen African countries. The eight treated in depth in this article account for three-quarters of installed IPP capacity and about 70% of all IPP investment.[6]

3. The authors also contributed findings on IPP experiences in Egypt, Kenya and Tanzania to a global IPP study, led by Stanford University's Program on Energy and Sustainable Development (PESD). See http://pesd.stanford.edu/ipps. Detailed research reports have also been prepared as part of a broader assessment of African IPPs undertaken by the Management Programme for Infrastructure Reform and Regulation (MIR). See http://www.gsb.uct.ac.za/gsbwebb/default.asp?intpagenr=309.
4. Côte d'Ivoire, Tanzania and Morocco IPPs currently contribute more than half of all generation.
5. The International Energy Agency reports installed capacity for Africa at approximately 112,000 MW as of 2004; with IPP installed capacity roughly equal to 9,500 MW, IPPs are just below 9% of total installed capacity on the continent (International Energy Agency, 2006: 527). It should, however, be noted that the IEA total installed capacity figure appears to be inflated, given data on systems; with no additional source providing comprehensive data on African installed capacity, the reference has nonetheless been included.
6. Although Mauritius has 4 IPPs (which, at approximately 200 MW combined, account for about 37% of installed capacity and a little less than 25% of production, as of end-2005), 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

Figure 1: Greenfield IPPs in Africa



Notes: Includes all IPPs that have reached financial closure (apart from South African AES IPPs where it is expected by 2008). Not included are cancelled IPPs, Songa (Congo) and SIIF Accra and Osagyefo Barge (also known as Western Power) (Ghana). Kenya's Westmont has since concluded its 7-year contract. Construction is not yet started on South Africa's peaker plants and Uganda's Bujagali.
Source: Based on the World Bank (2007b) and authors' compilation.

3 Understanding the experience of IPP investments in Africa

How may one understand the sample of IPPs highlighted above? There are two natural fault lines. The first cuts between North Africa and sub-Saharan Africa, and the second, between those projects in SSA that faced some form of contract change and those that did not.

The North African pool of projects is cited by stakeholders as having relatively favourable outcomes for sponsors and host countries alike. Furthermore, the relative absence of contract changes confirms this conclusion. In contrast, SSA projects have been repeatedly cited by myriad stakeholders as being out of balance, and the litany of contract changes would seem to confirm this. Many elements have contributed to the North African successes, especially favourable investment climates, the endurance of policy and planning frameworks, even in the face of exogenous stresses, international competitive bidding procedures and low-cost fuel. Furthermore, there are several key elements that differ between the SSA pool of projects that have faced contract changes and those that have not, most notably the emergency environment and the presence of multilateral and bilateral development institutions and/or development-minded firms.

shortfall, the CPPs also have long-term take or pay contracts with the state (Bergesen, 2007; World Bank, 2007a).

Not only have the above elements been instrumental in creating a greater balance at the start of the IPPs; they appear to have enhanced the sustainability of projects and contracts over time, particularly in the face of exogenous stresses.

3.1 Building up contributing elements to success, at country level

Favourable investment climate

Egypt, Morocco and Tunisia distinguished themselves from their SSA counterparts, with Tunisia scoring the highest in terms of its investment track record as evidenced by its investment grade ratings for foreign currency (BBB) and local currency (A). Both Egypt and Morocco score just one notch below investment grade (at BB+).

In contrast, the sub-Saharan IPP sample has no investment grade ratings. Of the three countries that have received a speculative rating (Ghana, Kenya and Nigeria), two of these ratings (Kenya and Nigeria) were given in the last two years, long after IPP deals were signed, with Kenya's investment climate defined by its aid embargo in the mid-1990s. Furthermore, Ghana's speculative rating (at B+) is four notches below investment grade and therefore not comparable with the speculative ratings of Egypt and Morocco. 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. To summarise, for each of the three North African IPP success stories described here, countries have either had an investment grade rating or one notch below, in contrast to the four SSA cases, where no country has received an investment grade rating and even speculative ratings have been few and far between.

Furthermore, despite the difference in the perception of the investment climate between North and sub-Saharan Africa, incentives offered to investors in IPPs were relatively similar across the pool of eight countries and 20 projects, with some variety with regard to tax breaks. For instance, nearly all 20 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 in virtually all of the projects. In terms of tax holidays, all three countries in the North African sample had tax holidays of five years. 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 perception of the investment climate impact on project development? Quite simply, with demand for IPPs outweighing supply, those countries with a better investment profile (primarily the North African sample) attracted more investors and ultimately were able to cement deals on terms more favourable to the host country. 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 so many of the SSA cases.

New policy frameworks and regulation

Although all eight 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. Thus there is abundant evidence of tentative experimentation with private power that does not always lead to a sustained opening of the market for private investment. 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 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., 2007a; b). All utilities evaluated were 100% state-owned with the exception of the Kenyan utility, which is owned 48% by the state, and the Nigerian utility, which is in the process of being privatised (however, this development occurred after the two contracts evaluated in this article were bid, and PHCN still maintains a co-ordinating role).[7] Thus, state-owned utilities remain in a dominant position, with IPPs on the margin and the future frameworks in many countries as yet undecided.

The most coherent policy framework exists in North Africa, with Egypt defining itself as the front-runner. In Egypt, 15 IPPs were specified by the Egyptian Electricity Authority (EEA, later the Egyptian Electricity Holding Company), which was clearly charged with carrying out the IPP programme following ICB practices. IPPs were to provide the majority of new generation capacity to the grid. They were also to assist in benchmarking state-owned and -operated plants and improve the overall performance of the sector. A regulator was to be integrated into the Electricity Supply Industry (ESI) and assist in supervision. Corporatisation and commercialisation of distribution assets were to follow. Of the numerous features of the policy framework, it was perhaps the clear mandate given to the EEA/EEHC to procure IPPs that helped define its early success. Even with a clear policy and the power to implement decisions, however, Egypt's IPP programme was derailed (after the first three plants were bid out), owing to macroeconomic shocks and a severe currency devaluation. In shelving the remaining plants, the government sought to reduce additional foreign-exchange risk. Furthermore, reform of the incumbent state-owned utility has been slow. Thus, policy was either not implemented or was rewritten during implementation, a practice evidenced across the sample, with the present policy framework in Egypt favouring a return to publicly-financed generation.

While more piecemeal than Egypt, Kenya's policy framework has yielded one element that the other seven countries in the sample have currently set aside or only pursued late in the game, namely, the establishment of an independent regulator to aid in sector supervision. In Kenya, the regulator, together with the adoption of ICB

7. In addition, it should be noted in this context that Côte d'Ivoire has had its state utility under a concession contract since 1990 – an arrangement that is expected to continue until 2020. Tanzania has just completed a 4-year management contract, and Kenya has just begun one.

practices, has helped to reduce PPA charges radically (between the first set of IPPs negotiated and the second). Kenya's Electricity Regulatory Board has also been instrumental in helping to set tariffs and manage the overall interface between private and public sectors. In Côte d'Ivoire, Egypt, 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, with, in the case of Egypt, the regulator's powers severely limited. Finally, no attempt to establish a regulator has been made in either Tunisia or Morocco, with the ministries the *de facto* regulators in these two countries. What has emerged as a general trend is that the mere presence of a regulator is not in itself a defining factor. 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 suggests that effective regulatory oversight may lead to a reduction in the stated capital costs of projects for selectively bid projects (Phadke, 2007: 10, 25).[8]

A final policy and practice is worth noting in this context: in three of the eight sample countries (Nigeria, Tanzania and Tunisia) efforts have been made to exploit stranded gas as part of the IPP programme.[9] In Nigeria, a reduction in gas flaring is central to the push for gas-fired power. In Tanzania, the IPP programme commercialised previously stranded (although not flared) gas via Songas and Mtwara. In Tunisia, although the primary goal was to attract new investment into the hydrocarbon sector, one significant spin-off has been the reduction of gas flaring. Each country has seen a distinct set of challenges;[10] 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.

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. 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.

For many of the sample countries, however, the future framework remains uncertain, even as there appear to be more concessionary loans available. As one policy-maker indicated: 'The government is reviewing the impact of IPPs and the trend in

8. 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).
9. Domestic gas reserves were used for IPPs in both Côte d'Ivoire and Egypt; 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 yet no private participation, and no power produced.
10. In Tunisia, gas quality has proved poor and water also flooded the wells; consequently the plant has been repeatedly offline. In Nigeria, although the gas is of good quality, 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.

countries like [ours]. [The utility] needs a breathing space. Soon[er] or later, the government will publish a strategic paper on the way forward.' In the meantime, in this same country, emergency power has been ordered to plug an immediate power crisis, as will be further explored below.

Coherent planning and execution

Intricately connected to sound policy frameworks are coherent power sector plans. Ideally, the latter follow from the former and include four 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 vesting planning and procurement in one empowered agency to ensure that implementation takes place with minimal mishaps.

The sample evaluated here has had several noteworthy planning mishaps. 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 Ghana's IPP were negotiated amidst drought conditions. 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.

An inability to estimate demand and supply accurately as well as set a clear reliability standard has also necessitated several cases of emergency power where units have been ordered for one to two years with the purpose of plugging a short-term crisis. In both 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 twice: in 1999-2001 and again in 2006 (supplied by Aggreko, Cummins and Deutz in the first instance and Aggreko alone in the second). Emergency power has been turned to repeatedly in Tanzania 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, as of 2007, seven years later, remains an unresolved conflict. 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 pers. comm. 24 January 2005). As previously noted, 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).[11]

11. 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, which is in line with the CUE in many industrialised countries (Global Energy Decisions, 2007).

In Tanzania, the speeding through of one plant 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 a defined agency to implement the plan.

The Songo Songo gas-to-electricity project was in the Power System Master Plan, initially slated to come on line 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 would later argue was inflated by 40%. 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 charges 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.

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 open bidding but under less cumbersome bidding procedures – 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.

Competitive bidding practices

While policy and planning frameworks go a long way in determining outcomes, the type of bidding has been linked to outcomes, with considerable attention paid to the importance of international competitive over selective bidding practices. Two recent studies have evaluated the relationship, demonstrating that, while there is evidence for ICBs leading to up to a 60% 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).

ICBs were conducted for 11 of the sample of 20 IPPs, including all three projects in Egypt and Morocco, and one of the two projects in Tunisia. In the East African group, ICBs have been less common, with three of the seven projects (OrPower4, Tsavo and Songas) recorded as having conformed with such bidding practices. In West Africa, an ICB was conducted for only one of the five projects (Azito).

In terms of gleaning meaning from ICBs versus selective bidding, of the six projects that have faced renegotiation, four were bid selectively rather than via an ICB (IPTL, Iberafrica, AES Barge and Okpai), 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 selectively bid projects have also, with the exception of CIPREL and Mtwara, encountered some difficulty or another, which has led to a change in how the project is being developed. Ghana's Takoradi II has not been able to raise the finance for the second phase of the plant, and Tunisia's SEEB has not been able to secure its fuel supply and is currently offline. 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 driving down prices. The number of bids submitted to ICBs in North Africa was generally double to triple those submitted to ICBs in East 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. 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.

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.

In three of the sample countries (Ghana, Kenya and Tanzania), at the inception of IPPs, low-priced hydropower was the dominant fuel source. In these countries, IPPs were thermal powered, using a combination of imported fuel oil and domestically procured natural gas. IPPs 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) were compared with state-owned, generally amortised hydropower, the new privately owned generation was seen to be largely more expensive, due partly to the energy/fuel charge. Furthermore, these countries witnessed a series of debilitating droughts over the course of the 1990s. Drought also wreaked havoc throughout the East African region between 2002 and 2006. 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% to 60% 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.

Contrast this story with Morocco and Nigeria. In Morocco, at the inception of IPPs, oil and coal, largely imported, were the incumbent fuels. Hydropower also played an important role in contributing to the generation mix. Through Jorf Lasfar, the country's first and largest IPP, Morocco changed its fuel composition; as of 2005, coal had become the dominant fuel, accounting for more than 60% of generation. Although only 50MW, the country's wind-power plant also contributed to the diversification, together with Tahaddart, which introduced over 300MW of natural gas-fired generation. Thus, like Kenya and Tanzania, Morocco has achieved fuel diversification through its IPPs; however, unlike the other two countries, it has seen prices come down, due to a host of factors, including the relatively cheaper price of imported coal, and the use of gas via the Algerian-Spain pipeline, which fuels Tahaddart and which the government receives as a royalty. Nigeria has relied entirely on domestically procured natural gas, and gas is the incumbent fuel. Until recently, although a series of issues affected project outcomes, most notably the investment climate and bidding procedures, fuel had not been an issue; however, recent civil unrest in the Niger Delta has led to a disruption in the fuel supply.

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. There are, however, several noteworthy exceptions. Tunisia's SEEB plant is one such. Although natural gas is the incumbent fuel in Tunisia, the SEEB plant was part of an initiative to attract investors to exploit stranded gas associated with oil production. Thus, since SEEB's fuel supply has been compromised, there has been no other source of supply for the plant. 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 imported fuel oil currently powering IPTL. There have, however, been significant delays in the conversion of the IPTL diesel units. Finally, in the case of Egypt, natural gas is the incumbent fuel and also the fuel of choice for all IPPs to date. Fuel is a pass-through to the utility, but currently not to the final consumer. Fuel is also subsidised. In the last few years, the country has emerged as the sixth largest liquefied natural gas (LNG) exporter in the world. At present a debate is raging about how to allocate the remaining natural gas reserves. Should they go for additional electric power generation, LNG export, or present and future industrialisation projects? 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 (for up to 30 years in the case of Jorf Lasfar and on average 20 years for the other projects). 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 2.

Table 2: Contributing elements to successful IPP investments within the purview of host governments

CES	Details
Favourable investment climate	Stable macroeconomic policies Legal system allows contracts to be enforced, laws to be upheld, arbitration 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
Clear policy framework	Framework enshrined in legislation Framework clearly specifies market structure and roles and terms for private and public sector investments (generally for single buyer model, not, yet, wholesale competition in African context) Reform-minded ‘champions’, concerned with long run, lead and implement framework
Clear, consistent and fair regulatory supervision	Improves general performance of private and public sector assets Transparent and predictable licensing and tariff framework improves investor confidence Cost-reflective tariffs ensure revenue sufficiency Consumers protected
Coherent power sector planning	Energy security standard in place; planning roles and functions clarified Vested with lead, appropriate (skilled, resourced and empowered) agency Takes into consideration hybrid market (public and private stakeholders and their respective real costs of capital) and fairly allocates new build opportunities among stakeholders Has built-in contingencies to avoid emergency power plants or blackouts
Competitive bidding practices	Procurement process is transparent; competition ultimately drives down prices
Abundant low-cost fuel and secure contracts	Cost-competitive with other fuels Contract safeguards affordable and reliable fuel supply for duration of contract

Note: Competent contracting capacity is also emerging as a critical piece of the equation, which may lead to more favourable outcomes. Such capacity may ultimately be best located in a single-buyer office. Fair dispatch, namely, the equitable dispatching of state-owned and privately owned plants, has also emerged as a critical piece of the equation, but is beyond the scope of this study.

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 to 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 development-minded firms such as IPS and Globeleq as well as DFIs? Table 3 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 firms were the dominant players in African IPPs. There were no exclusively locally sponsored projects, 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 of 3.2.[12] Following this logic, there were only two projects in the pool where local partners were the major stakeholder, Morocco's Tahaddart and Nigeria's Okpai. However, in both cases, the majority stakeholder was either the national utility or the national petroleum company. Furthermore, in the case of Morocco, Office Nationale de l'Electricité (ONE), the state utility, initially intended to hold only a 20% share and increased its share after Electricité de France (EDF) pulled out (Malgas et al. 2007a:16). In Okpai, the power project falls under the rubric of a state-led gas-flaring-reduction programme, in which international oil companies, currently operating in Nigeria, are being engaged in power projects. In the next such project, Afam, the Nigerian National Petroleum Corporation also has a majority share (55%).

Local participation has been cited as a possible means of reducing risk (Hoskote, 1995: 11; Woodhouse, 2005). A total of seven of the 20 projects had local equity participation, namely, Tahaddart, Iberafrica, IPTL, Songas, Takoradi II, AES Barge and Okpai. To what extent did such local participation impact favourably on outcomes? Of the seven projects, six have encountered some form of change to their contract. Furthermore, in four of these six projects, either the state utility or another government

12. Projects such as Osagyefo Barge in Ghana and several projects in Nigeria (Ibom and Omoku) have been largely financed by either national and/or state governments and have been loosely termed IPPs for the following reasons. In Ghana, private participation was expected, and in Nigeria, projects have been independent of the national utility, led entirely by the Rivers and Akwa Ibom State Governments, respectively. As of end-2006, however, Globeleq was 'pursuing' investment in the Ibom project, which would include both investment in the existing capacity and an addition of up to 500 MW (Globeleq, 2006:7).

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 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.

Table 3: Equity participation in IPPs

Project (country)	Equity partners (country, % of equity held)	Change in contract terms	Mj[a] equity turnover (#)
Sidi Krir (Egypt)	InterGen (US, 60%) & Edison (US, 40%) sold to Globeleq (UK, 100%) in 2004-5, conditional sale to PEL (JV between Malaysia Tanjong & Saudi Arabia Al Jomaih, 100%) in 2007	N	2
Port Said (Egypt)	EDF (France, 100%) sold to Kuasa Power, subsidiary of Tanjong (Malaysia, 100%) in 2006	N	1
Suez (Egypt)	EDF (France, 100%) sold to Kuasa Power (Malaysia, 100%) in 2006	N	1
Jorf Lasfar (Morocco)	CMS (US, 50%) & ABB (Swiss, 50%) sold shares to TAQA (UAE, 100%) in 2007	N	1
CED (Morocco)	EDF (France, 49%), Paribas (France, 35.5%) & GERMA (France, 15.5%) maintained equity since 1997	N	0
Tahaddart (Morocco)	ONE (Morocco, 48%), Endesa (Spain, 32%) & Siemens (Germany, 20%) maintained equity since 1999	N	0
Rades II (Tunisia)	PSEG (US, 60%) sold shares to BTU Power Co. (GCC,[b] 60%) in 2004, Marubeni (Japan, 40%) retained shares since 1999	N	1
SEEB (Tunisia)	Centurion (US, 50%) sold to Candex (Canada, 50%) in 2005, Caterpillar (US, 50%) maintained equity since 2002	Y	1
Westmont (Kenya)	Westmont (Malaysia, 100%) has sought to sell plant since 2004	-	-
Iberafrica (Kenya)	Union Fenosa (Spain, 80%), KPLC Pension Fund (Kenya, 20%) since 1997	Y	0
OrPower4 (Kenya)	Ormat (US/Israel, 100%) since 1998	Y	0
Tsavo (Kenya)	Cinergy (US) & IPS (Int'l) jointly owned 49. 9%, Cinergy sold to Duke Energy (US) in 2005, CDC/Globeleq (UK, 30%), Wartsila (Finland, 15%), IFC (Int'l, 5%) retain remaining shares since 2000	N	1
IPTL (Tanzania)	Mechmar (Malaysia, 70%), VIP (Tanzania, 30% *in kind*), both have sought to sell shares	Y	-
Songas (Tanzania)	TransCanada sold majority shares to AES (US) in 1999 & AES sold majority shares to Globeleq (UK) in 2003[c]	Y	2

Table 3: cont'd

Project (country)	Equity partners (country, % of equity held)	Change in contract terms	Mj[a] equity turnover (#)
Mtwara (Tanzania)	Artumas (Canada, 80%), FMO (Netherlands, 20%)	N	0
CIPREL (Côte d'Ivoire)	SAUR International, with 88% (JV between French SAUR Group owned by Bouygues, 65% & EDF, 35%) BOAD, PROPARCO, & IFC holding the remaining 12%; in 2005 all shares sold to Bouygues (France, 98%), except BOAD (2%)	N	1
Azito (Côte d'Ivoire)	Cinergy (JV between Swiss ABB, 50% & French EDF, 50%) holds 65.7% of shares, CDC/Globeleq (11%), & IPS (23%)	N	0
Takoradi II (Ghana)	CMS (US, 90%), VRA (Ghana, 10%), CMS sold shares to TAQA (UAE, 90%) in 2007	Y	1
AES Barge (Nigeria)	Enron (US, 100%) sold to AES (95%) & YFP (Nigeria, 5%) in 2000	Y	1
Okpai (Nigeria)	Nigerian National Petroleum Corporation (Nigeria, 60%), Nigerian Agip Oil Co. (Italy, 20%), & Phillips Oil Co. (US, 20%) maintained equity since 2001	Y	0

Notes: a) Column indicates number of times majority (Mj) equity share(s) traded hands, not minority. For instance, in case of Songas, majority shares have traded hands twice with three different lead sponsors; however, minority shares have been bought and sold many more times; b) BTU is owned by public and private investors in the Gulf Co-operation Council (GCC); c) Ocelot (Canada), TransCanada (Canada), TPDC (Tanzania), TANESCO (Tanzania), Tanzania Development Finance Co. Limited (TDFL) (Tanzania, sponsored by EIB), IFC (multilateral), DEG (German), CDC (UK) were shareholders by 1996, with TransCanada the majority shareholder; IFC & DEG sold shares to CDC in 1997/8; TransCanada sold shares to AES (US) 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 in Songas were as follows: Globeleq: US$33.8 m. (56%); FMO: US$14.6 m. (24%); TDFL: US$4 m. (7%); CDC: US$3.6 m. (6%); TPDC: US$3 m. (5%) and TANESCO: US$1 m. (2%), not reflecting the additional $50 m. that Globeleq committed for the expansion.
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 article 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). In Egypt, EDF has recently sold its assets to Tanjong, a Malaysian firm, and Globeleq has entered into a conditional sale for its entire Asian and North African portfolio, which includes Egypt's Sidi Krir, to a joint venture between Tanjong and Saudi-based Al Jomaih.[13] While it would be inaccurate to say that these firms overlooked the higher risk profiles of the African continent (and/or did not ultimately

13. Another example of an emerging-economy firm taking a market share is BTU, based in the Gulf Co-operation Council, which bought shares from PSEG Tunisia's Rades II plant in 2004.

charge higher returns), there may have been a greater willingness to consider investments in the first place.

While the number of developing/emerging-country-based firms appears to be growing, three of the southern-based firms are trying to sell their shares (Mechmar and VIP in IPTL and Westmont). Thus, the origin 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 firm origins 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. For instance, EDF had a long-term relationship with Egypt in terms of providing technical assistance. Union Fenosa, the parent company of Iberafrica, had an existing relationship with Kenya through an information-technology contract. IPS, a major shareholder in Tsavo and Azito, had operated in Kenya since 1963 and in Côte d'Ivoire since 1965. The Commonwealth Development Corporation (CDC), from which Globeleq was spun off, had a 50-year history in Tanzania. While the long-term presence of a firm does not appear to be decisive (as many such projects did face contract changes), it may help explain why more contracts did not unravel. Long-term relationships, with strong local management, appear to have contributed to the staying power of firms and often the rebalancing of contract terms.

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. Until May 2007, Globeleq held an 11% share in Côte d'Ivoire's Azito, a 100% equity stake in Egypt's Sidi Krir, 30% equity in Kenya's Tsavo and 56% in Tanzania's Songas. IPS holds a 23% share in Azito, and together with Duke Energy, a 49.9% share in Tsavo. IPS is also leading development of Uganda's Bujagali project, a 250 MW hydroelectric plant, which was formerly being developed by AES.

Although both Globeleq and IPS 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 CDC, the private-sector promotion arm of the UK Department for International Development. IPS is the operating arm of the Aga Khan Fund for Economic Development in the industrial sector throughout Asia and Africa. While projects for both 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.

None of the projects with involvement of such development-focused firms, except Tanzania's Songas, has seen any changes in contract terms, which may signal a greater perceived balance from project inception as well as a better ability to withstand public pressure. Furthermore, in terms of the Songas change, although the buying down of the allowance for funds used during construction (AFUDC) of US$103 m. brought about a reduction in the capacity charge, the firm received full payment upon the buy-down, and it therefore represents a different case from many of the contract changes cited above.

An important development must, however, be reiterated in this context. Globeleq, which until 2006 seemed to be expanding its portfolio of assets, is in the midst of selling off the brownfield plants it bought to position itself as a global greenfield developer. The firm always intended to take this course, since it saw its brownfield investments as part of a stop-gap measure during the global downturn in private power. Recent indicative bids for Globeleq's SSA assets were not, however, deemed viable, and therefore for the time being Globeleq is holding on to its stake in Azito, Tsavo and Songas. On the one hand, Globeleq's sale of Sidi Krir and its Asian assets signals that there may indeed be a renewed interest in private power. On the other hand, the absence of favourable bids for SSA indicates that such renewed interest is still limited in scope (beyond supplying emergency power), and there may indeed be need for this type of development-minded firm in less developed countries.

Meanwhile, the presence of DFIs persists in project equity. Although none of the North African projects had such participation, four of the SSA IPPs saw DFIs pick up equity shares. The International Finance Corporation holds a 5% share in Tsavo's equity. Until 2005, IFC also held, together with the West African Bank for Development (BOAD), the Investment and Promotions Company for Economic Co-operation (PROPARCO), a 12% 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 organisations selling their shares after the IPTL dispute became known. The Netherlands Development Company (FMO) maintains a 24% share in Songas (excluding the expansion of 65 MW) as well as a 20% share in Mtwara. CDC, independent of Globeleq, also holds a 6% 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 45 original equity partners in the sample pool, 15 have exited from 11 different projects. This statistic, however, tells only part of the story. First, as previously indicated, three shareholders have been actively trying for several years to sell their assets (both shareholders in Tanzania's IPTL and Kenya's Westmont). 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% 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, nine of the majority shareholders in the 20 projects have sold shares at least once and two have been actively seeking to do so for at least three 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. InterGen's reason for selling its interest in Egypt's Sidi Krir to Globeleq in 2004 was based on the fact that its shareholders (Bechtel and Shell) made a strategic decision to move out of the business of owning and operating private power facilities. For Bechtel this meant moving back to its core business of designing, engineering and building plants, but not operating and maintaining them; and for Shell, it meant focusing on the petroleum exploration and production business. Similarly, Edison has sold much of its global portfolio because of a decision to return to its core business in Italy. EDF also cites its plans of concentrating its investments in Europe. In terms of Tunisia's Rades II plant, PSEG described Tunisia as 'an excellent place to do business' and noted that 'the sale in no way reflects any unhappiness with [our] experience in Tunisia, but rather is in keeping with the company's stated strategy of reducing its international risks by selectively selling assets if they can obtain an attractive price' (Malgas et al., 2007b: 15).

How does this refrain square with the contract changes? The majority shareholders in two of the eight 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 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. In addition, although no contract changes are in evidence, one should not overlook the larger IPP programme change in Egypt. All three original sponsors have sold their assets, following the failure of the utility to follow through with 12 additional IPPs as originally specified, which could have given existing sponsors a larger market share.

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. The two exceptions here are again the Westmont plant, where the first PPA has expired and which was shrouded in controversy, and IPTL, which has been embroiled in lawsuits, and it may therefore be understandable why the plants have not attracted buyers. 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 as well as Globeleq's decision to hold on to its SSA portfolio, would, however, signal that some markets might actually be less mature than expected.

What, 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, and the presence of development-minded firms and development finance institutions.

Debt arrangements: global and local

With debt financing often covering more than 70% of total project costs, low-cost 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. The goal 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.

While there is no uniform pattern in the debt financing of the projects considered here, there is a series of trends in 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 twenty projects saw several notable exceptions, including Nigeria's Okpai plant, which was 100% financed by the balance sheet of equity partners, together with the second phase of Songas (however, refinancing is currently being pursued in this case). Westmont, Iberafrica and OrPower4 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 (CIPREL, Songas), IFC (Azito, Port Said, Suez, Tsavo), CDC (Tsavo, Azito), European Investment Bank (CED, Songas), DEG (Tsavo, Azito), FMO (Azito), African Development Bank (Azito) and PROPARCO (CED). In addition, a number of export credit agencies were involved in providing financing: the US Export Import Bank (Jorf Lasfar), the Overseas Private Investment Corporation of the United States, OPIC (Jorf Lasfar), and the Japan Bank for International Cooperation, JBIC (Rades II).

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.

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 Egypt's currency devaluation and 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, including via ICBs. The former plant saw no multilateral involvement in either its equity or debt, whereas, for the latter, IFC arranged all the debt and took a 5% 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 have been widely perceived as more balanced contract terms.

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. As previously noted, only one project across the pool, Morocco's Tahaddart, a 384 MW CCGT, 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% of total equity) as well as the fact that Morocco's commercial banks have a significant degree of state involvement.[14] With or without state involvement, no other country in Africa has, as yet, managed to arrange this level and depth of financing for IPPs. Thus, Morocco stands as a pioneer in this respect.[15]

The main drawback for IPPs without locally denominated finance is that projects may be subject to the effects of macroeconomic shock and currency devaluation. In Egypt, between the end of 2002 and early 2003, the currency lost half of its value and PPA payments in local currency terms doubled. In the short term, the US dollar- and/or Euro-denominated PPA provided substantial safeguards for sponsors, as equity and debt holders in Egypt did not see the value of their investments decline. The host country, however, paid dearly for the plants. Furthermore, one could argue that equity and debt holders did lose out indirectly due to the fact that a decision was made to cancel additional IPPs after the devaluation.[16] While no country in the sample other than Egypt experienced the crippling effects of macroeconomic shock, over the course of the decade Ghana, Kenya and Tanzania saw serious creeping devaluation, with their currencies losing more than 100%, 200% and 400% of their value, respectively, over the 1990s, which has inevitably had an impact on capacity charges.[17] There has been pressure to reduce such charges as well as to reconsider IPP development in each of these countries at different stages.

Although few projects have benefited from locally denominated financing, there are some promising signs, including in South Africa's IPPs. Sponsors for South Africa's two new peaking plants, totalling a combined 1000MW slated to come on line in 2009, have been given access to the country's capital markets, and capacity payments will be denominated in rand. Furthermore, four Nigerian firms (Farm Electric, Supertek, ICS and Eithope) have all been licensed to build power plants as of August 2006 with the expectation that power will start coming on line from these firms within four to five years, funded in part through domestic sources.

Where US dollar/Euro-denominated financing is the only possibility, the use of a foreign-exchange liquidity facility may be one solution, as it requires the PPA to be

14. Banque Centrale Populaire (BCP) put up MAD1300 m. and MAD960 m. was extended by a consortium of banks consisting of BCP as the lead lender, the Banque Marocaine pour le Commerce Extérieure (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).

15. Local currency financing has been recently employed by AES in Cameroon for the 80 MW Limbe power station (*Africa Electra*, 2005: issue 50). Stakeholders involved in Namibia's Kudu gas-to-power project are also raising the possibility of local currency financing.

16. Egypt's Sidi Krir plant did obtain local currency financing; however, it was US dollar-denominated, and therefore this ultimately did not help assuage the effects of the currency devaluation for the host country.

17. Morocco and Tunisia saw minimal fluctuations, and Nigeria's fluctuations were limited to the period before 1998, when the first IPP was negotiated. Côte d'Ivoire experienced a major currency devaluation in 1994; however, this predated the IPPs, and was prompted by a World Bank and IMF proposal rather than an exogenous macroeconomic shock.

indexed to the local currency inflation rather than the foreign-exchange rate, and hence power prices will not go up faster than domestic inflation.[18] In terms of the sample, however, the most widespread and effective practice witnessed to date is the indexation of payments to a basket of currencies, as seen in Morocco's Jorf Lasfar and CED and Tunisia's Rades II project.

Securing revenue: the PPA and other security arrangements

All of the projects evaluated had a long-term power purchase agreement with the (majority) state-owned utility to ensure a market for the power produced (with the exception of Mtwara).[19] Such a contract was demanded by equity and debt holders alike, given the lack of liquid markets for electricity in the sample. As a result, in most cases there was competition for the market, but no actual competition within the market once the PPAs were negotiated, with contracts averaging approximately twenty years.

In addition to indicating who would buy the power, the PPAs detailed how much power would be bought and at what cost. 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. Nearly all of the contracts specified some form of international dispute resolution and all but one (Tunisia's SEEB) specified a minimum availability.

These contracts were in turn backed by a series of security arrangements, including in some cases escrow accounts, letters of credit, stand-by debt facilities, committed public budget and/or taxes/levies, targeted subsidies and indexation in contracts. For instance, the Tsavo plant in Kenya, in which IPS is a major shareholder, has an escrow account equivalent to one month's capacity charge and a stand-by letter of credit from KPLC, which covers three months billing of approximately US$12 m. It is known that a minimum of eight of the twenty projects had either an escrow account or a liquidity facility or both, with typical terms being between one and four months capacity charge in reserve (with one month most typical for North African countries and up to four months seen in Tanzania).[20]

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18. There has, however, been only one such application to date, namely, the AES Tiete project in Brazil. A standby credit facility of US$30 m. was used to mitigate devaluation risk and closed in May 2001 (Matsukawa et al., 2003: 19).
19. Mtwara currently operates under a two-year interim PPA, which was expected to be replaced by a 20-year PPA in 2007.
20. Morocco's Jorf Lasfar has an escrow account equivalent to one month's capacity charge and Tahaddart has a letter of credit equivalent to one month's payment (which also serves as a form of liquidity facility). Tunisia's Rades II has an escrow account; however, the amount is not publicly available. 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 2 and 4 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 4 months capacity charge for the first 3 years, declining to 2 months starting in year 4 through the remaining years of the contract. To support its interim PPA, Mtwara has an escrow account (amount unpublished), which will be replaced by a form of liquidity facility, termed the Tariff Equalisation Facility, once the 20-

Not surprisingly, the number of security arrangements and 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 these plants.[21] Thus, the 'security arrangement' may lie not in a formal escrow account, but in an informal agreement among sponsors. In all but one case, as noted above, sponsors negotiated or were granted outright US dollar- or Euro-denominated PPAs, thereby reducing project sponsors' exposure to currency devaluation.

How, then, did the PPAs and security arrangements fare over time? Eight of the projects, nearly half, have faced some form of change to their contract. Thus, many have not proved iron-clad. Although there does not appear to be a strong pattern between security arrangements and contract changes (meaning that projects with either more or less security arrangements have been more or less susceptible to change), there is evidence for contract changes being directly related to the terms of the PPA in six projects.

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 a second contract, the sponsor voluntarily reduced its capacity charge, enshrined in the PPA, which meant that it did not amortise the full cost of the project over the first contract. At 15 years, Iberafrica's subsequent PPA is notably longer than its first (and with negotiations presided over by the Electricity Regulation Board, tariffs have been deemed significantly cheaper). The oft-referenced Westmont did not negotiate a second contract after it failed to obtain the same terms, namely, capacity charges, spelled out in its first PPA. The changes in Kenya's OrPower4 and Tanzania's Songas have also been related in part to the final amount of the capacity charge (as originally spelled out in the PPA).[22]

In terms of Nigeria's AES Barge, initially sponsored by Enron, the renegotiation 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 present renegotiations with AES Barge involve, among other things, reconsideration of the availability-deficiency payment. In each of the five 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 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.

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year PPA takes effect. Côte d'Ivoire's Azito plant has an escrow account equivalent to one month's capacity charge.

21. In 2005 it was found that the then Managing Director of KPLC, Samuel Gichuru, received US$2 m. from Westmont.

22. 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.

Thus, the PPA has been a central document; however, not necessarily because it has been bombproof. Rather, it has been the focal point of many of the discussions when deals have been considered out of balance.

Credit enhancements and other measures

Of the many different credit enhancements and other risk-management and mitigation measures, it is the provision for international arbitration and sovereign guarantees that has been most commonly employed. All projects in the pool specified some form of international arbitration. Sovereign guarantees were extended for seven of the 20 projects in the pool: all three of the Egyptian IPPs, Morocco's Jorf Lasfar, Tanzania's IPTL, Nigeria's AES Barge, Côte d'Ivoire's Azito and Ghana's Takoradi II. One of the projects without guarantees (Rades II in Tunisia) was, however, given added assurances by the government. 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 two of the projects: Jorf Lasfar and Azito. In the case of Jorf Lasfar, the partial risk guarantee protects the commercial lenders, should the off-taker and the government fail to make specified termination payments. In the case of Azito, a partial risk guarantee (PRG) ensures that commercial lenders will be paid, even if the utility and the state default on payments (of both interest and principal) (World Bank, 1997; 1999). In both cases, it is only after there is a breach in the sovereign guarantee that the PRG is triggered (Sinclair, 2007: 36).[23]

In addition, other measures were engaged. AES Barge has political risk insurance provided by OPIC. OrPower4 has a MIGA guarantee. Jorf Lasfar has political risk guarantees from the World Bank, the Italian Export Credit Agency and the Swiss Export Guarantee Agency. Despite the multitude of risks perceived, however, and the plenitude of risk insurances available, it is here that the list ends, with no cover for the majority of projects.

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

For each of the Egyptian IPPs, sponsors have indicated that the sovereign guarantees were essential to the deal, given the novelty and size of the projects. There is also evidence for Azito's partial risk guarantee being among the keys to attract commercial lending (World Bank, 1999). The lack of sovereign guarantees has also 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, 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. Across the board, sponsors of the Kenyan projects as well as KPLC cite the absence of sovereign guarantees as hampering the ability to raise private finance. ERB's rejoinder to this charge is that IPPs have been introduced to help commercialise the sector; government

23. Among the better documented World Bank partial-risk guarantees has been one extended for Uganda's electricity distribution concession with Globeleq (Globeleq, 2006: 21; Eberhard, 2007: 1).

guarantees work against this goal, and MIGA and other risk insurers are available to provide such cover.

Finally, 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.

Positive technical performance

Virtually all IPPs in the sample have shown positive technical performance, with exceptions noted in the case of Tunisia's SEEB and Nigeria's plants because of fuel supply. The performance of IPPs is generally superior to that of state-owned plants, with the example of Kenya highlighted here as an illustration. In terms of availability, between 2004 and 2006, IPPs had an average availability of approximately 95% versus KenGen's thermal plants, which averaged 60%.

Positive technical performance has been instrumental in changing the way IPPs are perceived. Consider, for example, IPTL, which performed optimally throughout the recent drought and helped Tanzania stave off load-shedding until 2006. The plant has since been termed 'a saviour', even by stakeholders who indicated that corruption was likely. At the same time, an unexpected break in Songas' power in 2006, in the middle of the drought, temporarily tarnished the project's reputation, despite the fact that the plant still reached its average availability as specified in the PPA and all costs were borne by Songas. During its ownership of Port Said and Suez, EDF noted that its management of technological risk, namely, by not outsourcing to any firms and handling all contracts within the fully integrated EDF, was also a key factor in leading to relatively positive outcomes for the firm (EDF pers. comm. 11 January 2005).

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 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. Jorf Lasfar received the American Chamber of Commerce award for community development and developed an ash disposal facility (previously ash was pumped into the sea). CMS's social responsibility involvement in Ghana included providing scholarships for secondary and tertiary education as well as support for medical clinics and the construction of drainage systems. 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 that such strategic management helped the Egyptian plants, which may be judged among the most successful in this pool of IPPs. There is also evidence that strategic management helped put Kenya's Iberafrica back on track, in contrast to Westmont, where no such action is in evidence. Finally, both of Tanzania's IPPs may credit future sustainability in part to such an element.

In the case of the Egyptian devaluation, EEHC appears to have approached the Sidi Krir management when the country was experiencing an acute scarcity of dollars to ask for payment in pounds to the maximum extent feasible, but due to its US dollar-denominated debt, the firm was unable to acquiesce. Minor changes, since the devaluation, are limited to partial payment of the local operating and maintenance component (both fixed and variable) in local currency, which amounts to approximately 4% of the total charge. With Sidi Krir, the change is based on an informal agreement between the project's general manager and EEHC. With Port Said and Suez, the agreement has gone through negotiations with the IFC, but EDF could have chosen to return to US dollar payments at any time, i.e. it was not bound contractually. Although small, these actions do send the message that sponsors are willing to work where possible to make the situation less onerous for the host country.

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 (the first lasted seven years). Iberafrica later secured a second contract, albeit after even further reductions were negotiated and passed by the electricity regulator.[24]

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 as Songas seeks to refinance its 100% equity investment in the second phase of the plant. Possible refinancing in the case of IPTL, with the Government of Tanzania proposing to buy the outstanding debt and possibly equity, could also lead to what may be perceived as more balanced outcomes. If and when the government buys back IPTL, it will make a one-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. Through this transaction, the capacity charge will be reduced to a token amount,

24. 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.

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.

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 Morocco's ONE assuming a greater equity share in Tahaddart when EDF pulled out and the Government of Tanzania's buying down of Songas' AFUDC.

The myriad project-level factors are summarised in Table 4.

Table 4: Contributing elements to successful IPP investments, project issues

CES	Details
Favourable equity partners	Local capital/partner contribution, where possible Risk appetite for project Experience with developing-country project risk Involvement of a DFI partner (and/or host country government) Reasonable, fair ROE Development-minded firms
Favourable debt arrangements	Low cost financing Local capital/markets mitigate foreign-exchange risk Risk premium demanded by financiers or capped by off-taker matches country/project risk Some flexibility in terms and conditions (possible refinancing)
Secure and adequate revenue stream	Commercially sound metering, billing and collections by the utility Robust PPA (stipulates capacity and payment as well as dispatch, fuel metering, interconnection, insurance, *force majeure*, transfer, termination, change of law provisions, refinancing arrangements, dispute resolution, etc.) Security arrangements where necessary (escrow accounts, letters of credit, stand-by debt facilities, hedging and other derivative instruments, committed public budget and/or taxes/levies, targeted subsidies and output-based aid, hard currency contracts, indexation in contracts)
Credit enhancements and other risk management and mitigation measures	Sovereign guarantees Political risk insurance Partial risk guarantees International arbitration

Table 4: cont'd

CES	Details
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

Notes: ROE: return on equity; O&M: operation & maintenance

4 Conclusion

In conclusion, perception of balance emerges as a particularly important determinant of project outcomes. On the one hand, where there was a perceived balance between sponsors and host-country governments, contracts generally remained intact, as seen in most of the North African cases, the contributing elements of success being the more favourable country-level factors (such as favourable investment climates, clear policy frameworks, and ICBs, among others). On the other hand, perceived imbalances (often exaggerated by exogenous stresses) between sponsors and host-country governments frequently led to an unravelling of the original contract. Neither the PPA, nor the security arrangements, were sufficient in locking in long-term sustainability in these cases.

Although the evidence is not conclusive, strategic management on behalf of sponsors and government as well as strong technical performance have been used to cope with contract instability. Furthermore, the fact that projects with participation of development-minded 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.

Thus, the findings are four-fold. First, evidence for contract unravelling is widespread across the pool of African IPPs where an imbalance is perceived, which largely corresponds to the more risky SSA projects. Secondly, the incidence of such unravelling does not necessarily signal the end of a project's operation. New agreements may be reached, albeit at a cost, that prove sustainable. Third, efforts must continue to close the initial gap between investors and host-country governments (or else examples of further contract unravelling will arise). Finally, the means of closing the gap may not be only, or mainly, via increasing the sort of new protections, including political risk insurance, which have often been reported to confound political and economic issues. They may instead lie in systematic treatment of the numerous contributing elements to success defined by this study.

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