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Energy and Mining

Independent Power Projects in Sub-Saharan Africa

Lessons from Five Key Countries

Anton Eberhard, Katharine Gratwick, Elvira Morella, and Pedro Antmann

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Foreword

Access to electricity is fundamental to development and a key driver for Sub-Saharan Africa's economic growth. However, a majority of countries in the subcontinent are still experiencing power shortages, and two out of three households, or close to 600 million people, have no electricity at all. Without electricity, health clinics struggle to provide basic services, children are unable to get a proper education, and businesses cannot grow and thrive in today's global economy. If we do not address the underlying reasons preventing Africans from achieving wider access to reliable and affordable electricity, economic growth on the continent will slow, keeping millions trapped in poverty.

Among the many development challenges facing Sub-Saharan Africa is the urgent need to increase power generation capacity. The financing requirements of the power sector far exceed most countries' already stretched public finances. Therefore, greater volumes of private investment will be critical to scale up generation capacity and thereby expand and improve electricity supply.

While public and utility financing has traditionally been the largest source of investment in power generation, independent power projects (IPPs) are now growing rapidly. They presently constitute the primary vehicle for private investment in the African power sector and most likely will continue to do so for the foreseeable future.

Currently, 126 IPPs are present in 18 countries of Sub-Saharan Africa. Together, they account for more than 13 percent of the subcontinent's total installed generation capacity—25 percent if South Africa is excluded. This is a notable share of total generation, given that most IPP investment has occurred in just the past few years. However, IPP investments could be much larger and less concentrated. South Africa alone accounts for 62 percent of IPP capacity; most of the remaining projects are located in a handful of countries. Many more African countries could and should benefit from such investments.

Although African governments strive to foster private sector participation, increased private investment will not materialize just because the need is great. Investments will flow where rewards demonstrably outweigh risks, while governments will demand investments that serve the public interest and support poverty reduction and growth targets.

Investment and development imperatives are often difficult to balance. The objective of this study is to evaluate the experience of IPPs and to identify lessons that can help African countries attract more and better private investment. At the core of this analysis is a reflection on whether IPPs have benefited Sub-Saharan Africa and how such transactions might be improved.

The analysis is based primarily on in-depth case studies carried out in five countries—Kenya, Nigeria, South Africa, Tanzania, and Uganda—that have the most extensive experience with IPPs. An unprecedented body of data has been collected and analyzed.

This report highlights not only the challenges that policy makers are facing but also the underlying factors that contributed to healthy investment climates. Ultimately, the report is intended to offer references, options, and tools that may help African countries achieve scaled-up and sustainable power sector investment for the benefit of their people and their economies as a whole.

Makhtar Diop
Vice President, Africa Region
World Bank

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Pedro Antmann is a lead energy specialist at the World Bank, working in the areas of institutional restructuring, regulation, tariffs, and management of utilities, including incorporation of information technology (IT) applications. Since September 2008, he has served as a member of more than 50 project teams in the six regions in which the Bank develops operations. From 1979 to 1995, he worked for Uruguay's state-owned vertically integrated electricity company (UTE) in the areas of thermal power generation (operating existing plants and planning and commissioning new ones), transmission, international power exchanges, distribution, and retail. From 1995 to 1997, he served in Uruguay's Ministry of Industry, Energy, and Mines, initially as director of the National Board of Energy and later as deputy minister of industry, energy, and mines, in charge of energy. From 1998 to 2000, he was associated with the French water and sanitation company Suez Lyonnaise des Eaux as international manager, in charge of operations of an affiliate company serving 3 million customers in Buenos Aires, Argentina. More recently (2000–08), he served as partner and senior consultant in Mercados Energy Markets International, a consultancy company specialized in institutional restructuring, regulation, and management of the energy sector. There, he conducted projects in more than 40 countries in the fields of design and implementation of new regulatory frameworks, tariff setting for network industries, management of utilities (including incorporation of IT applications), rural electrification, and benchmarking studies for electricity companies.

Executive Summary

Introduction

The track record of Sub-Saharan Africa's power sector is dismal. Two out of three households in Sub-Saharan Africa, close to 600 million people, have no electricity connection. Most countries in the region have pitifully low access rates, including rural areas that are the world's most underserved. In some countries, less than 5 percent of the rural population has access to electricity.

Chronic power shortages are a primary reason. The region simply does not generate enough electricity. The Republic of Korea alone generates as much electricity as all of Sub-Saharan Africa. Across the region, per capita installed generation capacity is barely one-tenth that of Latin America.

The need for large investments in power generation capacity is obvious, especially in the face of robust economic growth on the continent, which has been the key driver of electricity demand over the last decade. The International Energy Agency predicts that the demand for electricity in Sub-Saharan Africa will increase at a compound average annual growth rate of 4.6 percent, and by 2030 it will be more than double the current electricity production. The World Bank estimated in 2011 that Sub-Saharan Africa needed to add approximately 8 gigawatts (GW) of new generation capacity each year through 2015 (Eberhard and others 2011). But, in fact, over the last decade an average of only 1–2 GW has been added annually.

The cost of addressing the needs of Sub-Saharan Africa's power sector has been estimated at US$40.8 billion a year, which is equivalent to 6.35 percent of Africa's gross domestic product (GDP). The existing funding is far below what is needed. This large funding gap cannot be bridged by the public sector alone. Private participation is critical. Historically, most private sector financing has been channeled through independent power projects (IPPs). IPPs are defined as power projects that mainly are privately developed, constructed, operated, and owned; have a significant proportion of private finance; and have long-term power purchase agreements (PPAs) with a utility or another off-taker.

Like any other private investment, IPPs will not materialize in the absence of a suitable enabling environment. The primary objective of this study is to evaluate the experience of IPPs and see what is necessary to maximize their contribution to mitigating Sub-Saharan Africa's electric power woes.

Investment in Power Generation in Sub-Saharan Africa: An Overview

Current Power Generation Systems in Sub-Saharan Africa

In 2012, the 48 countries of Sub-Saharan Africa had a total grid-connected power generation capacity of only 83 GW. South Africa accounts for over half of this total. The remaining Sub-Saharan African countries have a combined capacity of only 36 GW, and just 13 of these countries have power systems larger than 1 GW. Twenty-seven countries have grid-connected power systems smaller than 500 megawatts (MW), and 14 have systems smaller than 100 MW.

Across Sub-Saharan Africa (excluding South Africa, which uses mostly coal), hydropower contributes just over half the capacity. Fossil fuels, primarily natural gas and diesel or heavy fuel oil, along with some coal, make up almost all the remainder. Renewables such as biomass, geothermal, wind, and solar add about 1 percentage point.

Power Generation Capacity Additions and Investment over the Past 20 Years

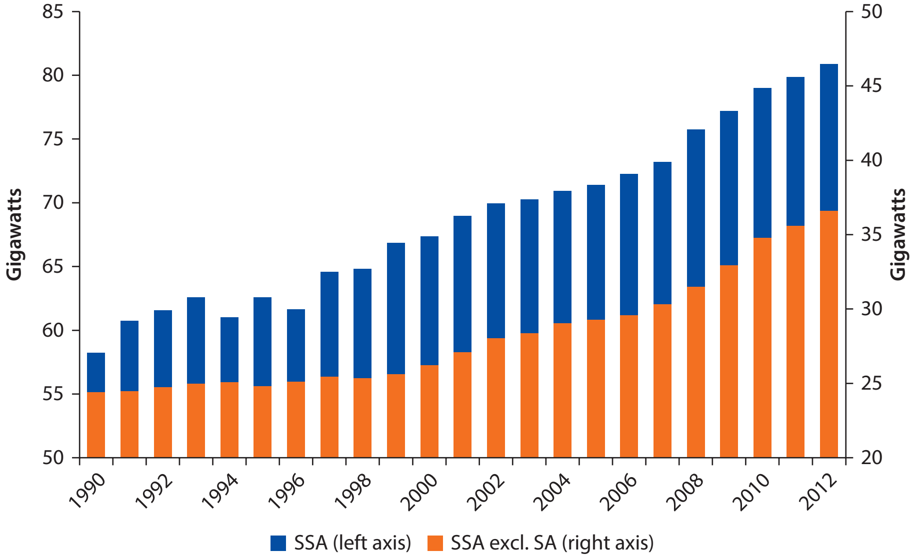
Between 1990 and 2013, only 24.85 GW of new generation capacity was added across Sub-Saharan Africa, of which South Africa accounted for 9.2 GW (figure ES.1). In the first decade of this period, 1990 to 2000, the countries of Sub-Saharan Africa other than South Africa added only 1.84 GW, and some even lost capacity. Between 2000 and 2013, investments picked up in these countries with an additional 13.8 GW installed. However, 94 percent of this increase occurred in only 15 countries, leaving dozens that added hardly any capacity at all. And as in the decade between 1990 and 2000, some actually lost capacity. Civil strife and lack of adequate system maintenance were the prevalent causes.

Between 1990 and 2013, investments in new power generation capacity totaled approximately $45.6 billion ($31.3 billion, excluding South Africa), or far below what is required to meet Africa's growth and development aspirations (table ES.1). Although public utilities have historically been the major sources of funding for new power generation capacity, that trend is changing. Most African governments are unable to fund their power needs, and most utilities do not have investment-grade ratings and so cannot raise sufficient debt at affordable rates. Official development assistance (ODA) and development finance institutions (DFIs) have only partially filled the funding gap. ODA and concessional funding has fluctuated considerably over the past two decades and has recently been overshadowed by IPP and Chinese-supported investment. Indeed, private investments in IPPs and Chinese funding are now the fastest-growing sources of finance for Africa's power sector (figure ES.2).

Independent Power Projects

IPPs in Sub-Saharan Africa date to 1994. Representing a minority of total generation capacity, IPPs have mainly complemented incumbent state-owned utilities.

Figure ES.1 Grid-Connected Generation Capacity: Sub-Saharan Africa, 1990–2013



Source: Authors' compilation of data from U.S. EIA 2014.
Note: SA = South Africa; SSA = Sub-Saharan Africa.

Table ES.1 Total Investment in Completed Power Generation Plants: Sub-Saharan Africa (Excluding South Africa), 1990–2013

Type of investment	*Debt and equity (US$, millions)*	*MW added*	*% of total MW*	*% of total investment*
Government and utilities	15,883.87	8,663.26	43.66	50.67
IPPs	6,950.12	4,760.60	23.99	22.17
China	5,009.80	3,263.73	16.45	15.98
ODA, DFI, and Arab funds	3,506.48	3,156.15	15.91	11.18
Total	**31,350.27**	**19,843.73**	**100.00**	**100.00**

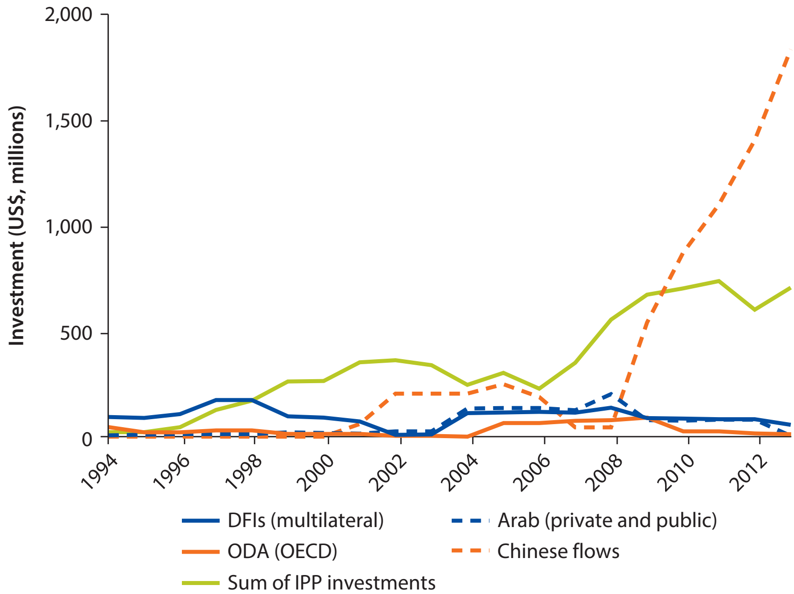
Source: Compiled by the authors, based on various primary and secondary sources. For more information, see table 2.4 in chapter 2.
Note: DFI = development finance institution; IPP = independent power project; MW = megawatt; ODA = official development assistance.

Nevertheless, IPPs are an important source of new investment in the power sector in a number of African countries.

IPPs are now present in 18 Sub-Saharan countries—all with varying degrees of sector reform and private participation. Currently, 59 projects (greater than 5 MW) are in countries other than South Africa, totaling $11.1 million in investments and 6.8 GW of installed generation capacity. Including South Africa adds 67 more IPPs, bringing the total to 126, with an overall installed capacity of 11 GW and investments of $25.6 billion.

IPPs in Sub-Saharan Africa range in size from a few megawatts to around 600 MW. The overwhelming majority of IPP capacity (82 percent) is thermal; only 18 percent is fueled by renewables. However, there is important growth in

Figure ES.2 Investments in Power Generation, Five-Year Moving Average: Sub-Saharan Africa (Excluding South Africa), 1994–2013



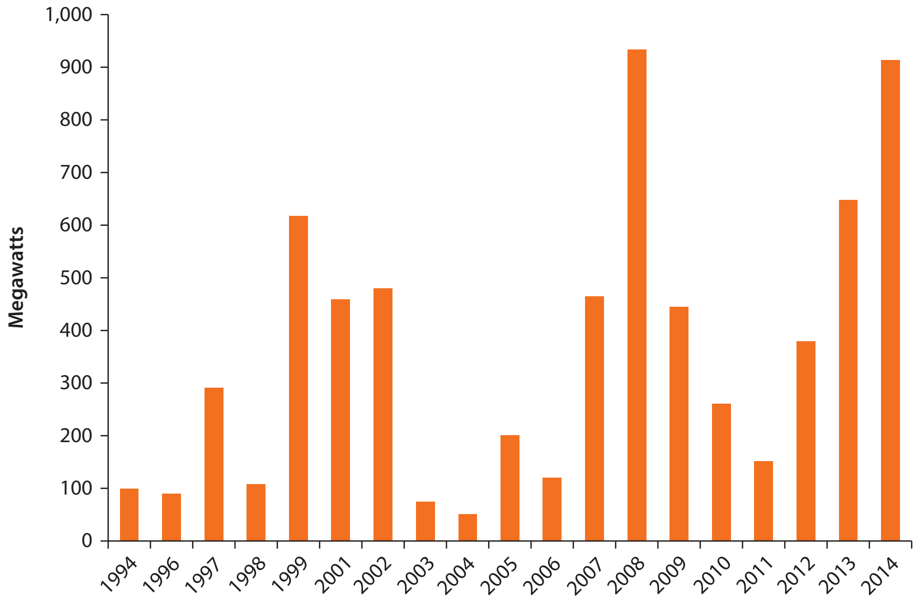
Source: Compiled by the authors, based on various primary and secondary sources.
Note: Ghana's Kpone IPP and Nigeria's Azura investments in 2014 and 2015, respectively, which together total $900 million, will result in a continued upward tick in IPP investments. DFI = development finance institution; IPP = independent power project; ODA = official development assistance; OECD = Organisation for Economic Co-operation and Development.

renewables. For example, three wind projects reached financial close between 2010 and 2014, and seven small hydropower projects are on the horizon. South Africa procured 3.9 GW in private power between 2012 and 2014, all of which is renewable.

As shown in figure ES.3, there have been three major IPP investment spikes: 1999–2002, 2008, and 2011–2014. The first two spikes were due to the financial close of a small number of comparatively large projects. In 2011, IPP investments began taking off. Excluding South Africa, total IPP investment for projects in Sub-Saharan Africa between 1990 and 2013 was $8.7 billion, whereas in 2014 alone another $2.3 billion was added. Previously, IPP investments in South Africa had lagged those in other Sub-Saharan countries, but between 2012 and 2014 that country closed $14 billion in renewable energy IPPs.

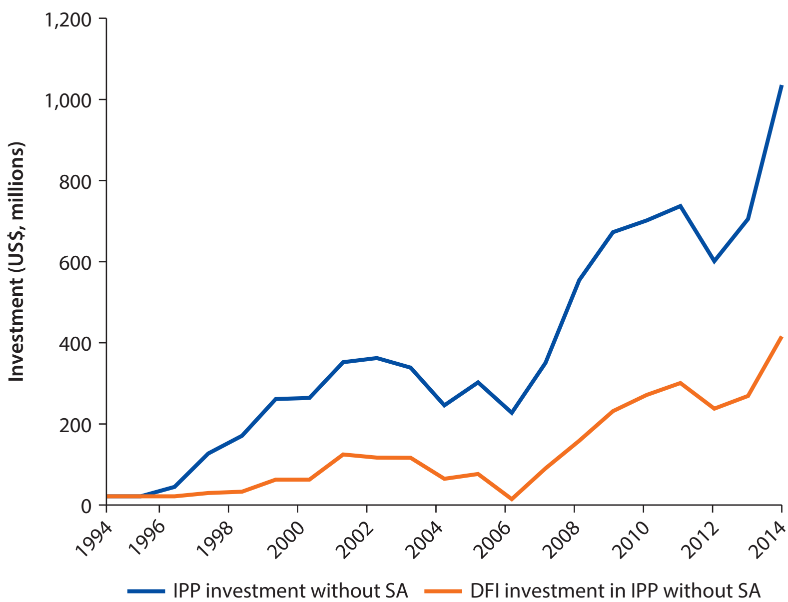
Although the conditions were varied in the countries where IPPs and other private participation took root, certain themes were common. With the exception of South Africa and Mauritius, none of the Sub-Saharan African countries with IPPs had an investment-grade rating. The possibility of a traditional project-financed IPP deal in this climate was limited. DFIs that invest in the private sector have made a significant contribution to funding IPPs (figure ES.4).

Figure ES.3 Independent Power Projects, by Year of Financial Close: Sub-Saharan Africa (Excluding South Africa), 1994–2014



Source: Compiled by the authors, based on utility data, primary sources, and the Private Participation in Infrastructure (PPI) database.
Note: No projects reached financial close in 1995 or 2000.

Figure ES.4 Total Investment by IPPs and by Development Finance Institutions: Sub-Saharan Africa (Excluding South Africa), 1994–2014



Source: Compiled by the authors, based on various primary and secondary sources.
Note: DFI = development finance institution; IPP = independent power project; SA = South Africa.

Table ES.2 Largest Chinese-Funded Projects in Sub-Saharan Africa, by Investment and Capacity, 2001–14

Project	*Country*	*Investment (US$, millions)*	*Capacity (MW)*
Karuma Hydropower Project	Uganda	1,688	600
Zungeru Hydropower Project	Nigeria	1,293	700
Morupule B Power Station	Botswana	970	600
Omotosho Power Plant II (NIPP)	Nigeria	660	513
Memve'ele Hydropower Project	Cameroon	637	201
Bui Hydropower Project	Ghana	621	400
Soubré Hydropower Project	Côte d'Ivoire	571	270

Source: Compiled by the authors, based on various primary and secondary source data.
Note: MW = megawatt; NIPP = national integrated power project.

Chinese-Funded Power Generation Projects

In addition to IPPs, significant increases in generation capacity have stemmed from Chinese-funded projects. Chinese-funded generation projects can be found in 19 countries in Sub-Saharan Africa. Eight of these countries have IPPs as well as Chinese-funded projects.

Between 1990 and 2014, there were 34 such projects in Sub-Saharan Africa, totaling 7.5 GW. Chinese-funded projects far exceed IPPs in terms of total megawatts, especially for the years 2010–14, with an average size of 226 MW, in contrast to the IPP average of 98 MW. As of 2014, Chinese-funded projects exceeded IPPs in total megawatts and in total dollars invested.

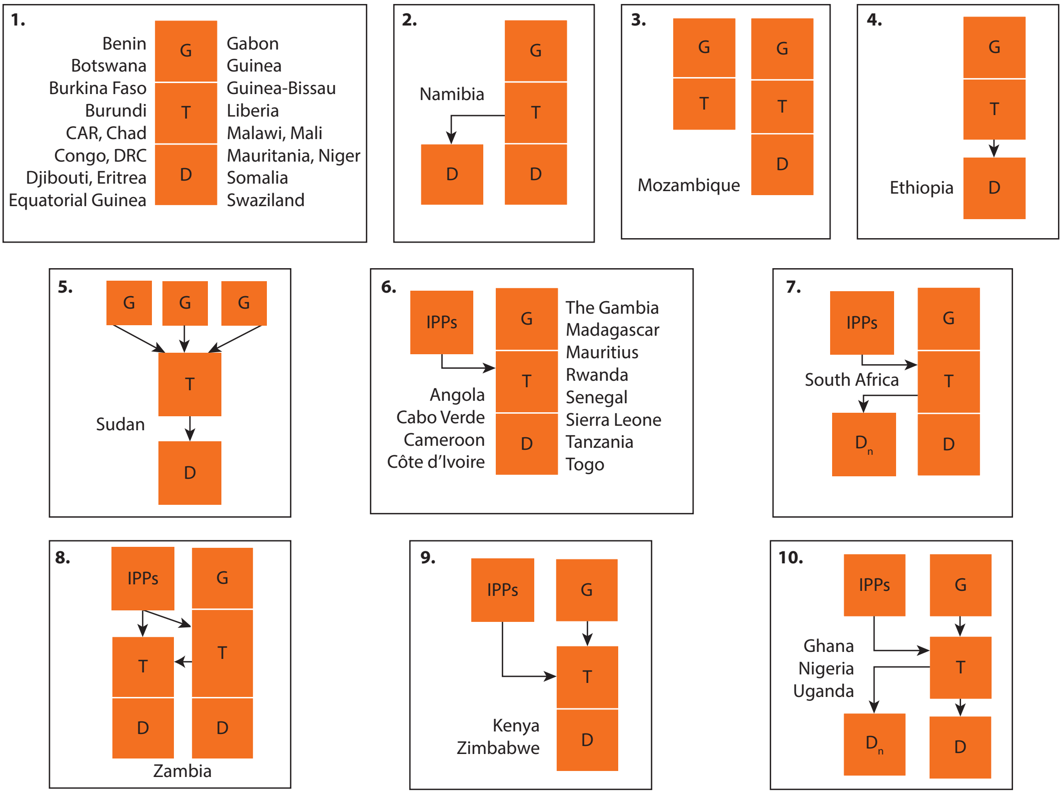
The majority of Chinese-funded projects are large hydropower projects (table ES.2), for which Chinese engineering, procurement, and construction contractors have become renowned worldwide. The typical project structure involves a contractor plus a financing contract. The majority of these projects received funding from the China ExIm Bank (responsible for soft loans and export credit) on behalf of the Chinese government. Additional finance has been provided by other banks owned in whole or part by the Chinese government.

Factors that Support Independent Power Projects and Their Success

Power Sector Reforms and Independent Power Projects

In recent decades, in response to the poor financial and technical performance of their power sectors, developing countries were encouraged to unbundle their electricity utilities, vertically and horizontally, to introduce competition, to create independent regulators, and to make space for private sector participation. As of 2014, however, 21 of the 48 Sub-Saharan countries still had state-owned and vertically integrated utilities with no private sector participation (figure ES.5, model 1). The second-largest group of countries also had vertically integrated state-owned utilities but, in addition, had introduced IPPs. A much smaller group of countries had unbundled power generation from transmission and distribution, and also incorporated IPPs.

Figure ES.5 Electricity Sector Structures: Sub-Saharan Africa, 2014



Source: Compiled by the authors, based on various primary and secondary source data.
Note: Includes vertical integration or unbundling of generation (G), transmission (T), and distribution (D) and presence of IPPs. While there are 48 Sub-Saharan African countries, the Comoros, Lesotho, São Tomé and Príncipe, and the Seychelles are excluded from this figure. Thus the three island states are not included, along with Lesotho, where the national utility, Lesotho Electricity Company (LEC), has only T&D assets. A separate generation plant, the Muela Hydroelectric Station (72 MW), is owned and operated by the Lesotho Highlands Development Authority (owned by the government of Lesotho). These countries otherwise form part of the overall analysis. It should be noted that Kenya also has an unbundled transmission company, the Kenya Electricity Transmission Company Limited (KETRACO), which is responsible for new transmission assets. Furthermore, Uganda has one large, privatized distribution utility supplied from the transmission grid and some regional distribution companies not connected to the main transmission grid. Finally, some of the countries listed in model 1 can, in principle, allow private investments, but as of yet do not have IPPs. CAR = Central African Republic; Congo = Republic of Congo; DRC = Democratic Republic of Congo; IPP = independent power project; MW = megawatt; T&D = transmission and distribution.

The model that has emerged from these reform efforts is a hybrid market in which public and private investment coexist. The characteristics of such power markets need to be recognized explicitly, as they present an array of challenges.

IPP investments have arisen in a variety of power market structures, indicating that no particular reform is the key. Nonetheless, unbundling, independent regulation, privatization, and competition are all significant where they improve overall sector governance, strengthen the enabling environment, and reduce the risk perceived by prospective investors. Key elements in supporting IPPs include planning the expansion of least-cost generation, streamlining procurement and contracting processes, and ensuring the financial health of off-taker utilities.

An important lesson is provided by the second wave of power sector reforms that occurred in regions such as Latin America. Most Latin American countries had undergone a process of unbundling, privatization, and the establishment of wholesale spot markets. Even so, it became clear that long-term contracts with financially viable off-takers were critical to generate secure and reliable financial flows to pay for large investments. A second wave of reforms shifted emphasis to long-term generation and transmission expansion. Of particular importance were efforts to improve the technical and financial performance of electricity distribution.

The Importance of Independent Regulation

By definition, IPPs are investment transactions regulated by the underlying contracts. Regulations at the sector level, although they do not directly influence the details of these contracts, are important in defining the rules of the game and ultimately shaping the enabling environment for IPPs.

The establishment of independent regulators has been the most widespread power sector reform element in Sub-Saharan Africa. As of 2014, more than half of all Sub-Saharan African countries had established such agencies, and the countries with the most IPPs all have electricity regulators. The mere presence of such an agency, however, is not sufficient. The quality of regulation is critical. Transparent, fair, and accountable regulators that produce credible and predictable regulatory decisions are necessary for creating the certainty around market access, tariffs, and revenues that encourages investment.

Ideally, an independent regulator should enforce best practices in investment transactions and notably competitive procurement. In Sub-Saharan Africa, the presence of a regulator is not necessarily associated with more competitive procurement practices, and regulators have not always ensured that captive electricity consumers benefit from the pass-through of competitive generation prices. The independence of regulators may be compromised by overreaching and competing government agencies. In many countries, the independence and professional capacity of regulators need to be strengthened so that they can discourage directly negotiated generation contracts and instead enforce the rules for the competitive procurement of IPPs.

Generation Planning, Procurement, Contracting, and Financial Sustainability

A range of generation planning arrangements is in place across the region. Although there is no optimal solution, some key lessons can be observed. If the planning function remains with the national utility, strong political leadership is crucial to ensure that the utility works to achieve national goals. Alternatively, the planning function may be transferred to an unbundled, independent transmission or system operator. If this transfer is to be successful, the planning function needs to be properly resourced. The majority of Sub-Saharan African countries have an inadequate planning capacity and end up contracting out this function to consultants.

Electricity plans need to be translated into timely procurement and well-delineated investment opportunities for the private and public sectors. Unfortunately, few African countries have an explicit connection between planning and procurement. More important, competitive bidding is not the norm. A disproportionate number of IPPs are developed based on unsolicited proposals and through direct negotiation.

IPP contracts typically extend from 15 to 30 years. This is both a strength and a weakness. Predictable revenue streams allow equity risk capital to be rewarded, and sponsors can also service debt with long tenors. Conversely, in an environment of power market reform, both parties can encounter problems with fixed long-term take-or-pay contracts if the various conditions under which the contracts are agreed upon change.

Because of the complexities involved, governments and national utilities need to marshal specialized expertise on a par with that of the private sponsors to negotiate robust and competitive IPP contracts. Governments have to allocate clear contracting responsibility to either the national utility or a government agency. If the national utility is to be responsible, then it is also critical that a ring-fenced contracting function be established, separate from the utilities' own generation or new build function. The best location may be an independent system operator that also takes responsibility for planning, which may then be integrated with the procurement function. In this case, the system operator assumes responsibility for both the system's short-term balance and the long-term security of supply.

At the crux of the investment conundrum is the financial viability of the off-taker. High transmission and distribution (T&D) losses, tariffs below cost recovery levels, and poor billing and collections severely affect the financial standing of utilities. Average distribution losses in Sub-Saharan Africa are high, and average collection rates are not high enough. Combined, this inefficiency is equivalent to 50 percent of turnover on average.

Governance reforms can critically improve the performance of state-owned utilities. Most utilities in Sub-Saharan Africa meet only about half of the criteria for good governance. Operational practices targeting technical and commercial efficiency can critically improve the financial standing of a utility in a short period of time. Because of concerns about the financial health of the off-taker, robust PPAs in a strong currency and bolstered by guarantees have become a requirement for new investors seeking to safeguard payment streams.

A Framework for Understanding the Enabling Environment for IPPs

The elements that contribute to sustainable IPP investments have been identified (table ES.3). Host country governments have an immediate influence over some of the elements. These include policy, regulation, planning, and competitive procurement. Overall economic conditions and the legal framework are clearly relevant, as are policies that encourage private investment in general and in the power sector in particular. Stable macroeconomic policies, investment protection, respect for contracts, capital repatriation, tax incentives, and further

Table ES.3 Factors Contributing to Successful Independent Power Project Investments, Sub-Saharan Africa

Factor	*Details*
Country level	
Stable country context	Stable macroeconomic policies
	Legal system allows contracts to be enforced, laws to be upheld, arbitration
	Good repayment record and investment-grade rating
	Previous experience with private investment
Clear policy framework	Framework enshrined in legislation
	Framework that clearly specifies market structure and roles and terms for private and public sector investments (generally for a single-buyer model, since wholesale competition is not yet seen in the African context)
	Reform-minded "champions" to lead and implement framework with a long-term view
Transparent, consistent, and fair regulation	Transparent and predictable licensing and tariff framework
	Cost-reflective tariffs
	Competitive procurement of new generation capacity required by regulator
Coherent power sector planning	Power planning roles and functions clarified and allocated
	Planning function skilled, resourced, and empowered
	Fair allocation of new build opportunities between utility and IPPs
	Built-in contingencies to avoid emergency power plants or blackouts
Competitive bidding practices	Planning linked to timely initiation of competitive tenders/auctions
	Competitive procurement process adequately resourced and fair and transparent
Project level	
Favorable 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
Favorable debt arrangements	Competitive financing
	Local capital/markets that 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)
Creditworthy off-taker	Adequate managerial capacity
	Efficient operational practices
	Low technical losses
	Commercially sound metering, billing, and collections
	Sound customer service
Secure and adequate revenue stream	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, and so on)
	Security arrangements where necessary (escrow accounts, letters of credit, standby 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)

table continues next page

Table ES.3 Factors Contributing to Successful Independent Power Project Investments, Sub-Saharan Africa *(continued)*

Factor	*Details*
Credit enhancements and other risk management and mitigation measures	Sovereign guarantees Political risk insurance (PRI) Partial risk guarantees (PRGs) International arbitration
Positive technical performance	Efficient technical performance high (including availability)
	Sponsors who anticipate potential conflicts (especially related to O&M and budgeting) and mitigate them
Strategic management and relationship building	Sponsors who work to create a good image in the country through political relationships, development funds, effective communications, and strategic management of their contracts, particularly in the face of exogenous shocks and other stresses

Source: Adapted from Eberhard and Gratwick 2011.
Note: DFI = development finance institution; IPP = independent power project; O&M = operations and maintenance; PPA = power purchase agreement; ROE = return on equity.

IPP investment opportunities will attract more capital at lower cost. Transparent, consistent, and fair regulatory oversight, with a commitment to cost-reflective tariffs, provides more price and revenue certainty, boosting the creditworthiness of off-takers and thus requiring less risk mitigation. Power planning and timely initiation of competitive tenders or auctions for new capacity are also important.

The balance of issues is within the project purview. At the project level, debt and equity finance has to be appropriately structured and serviced through revenue guaranteed in a robust PPA and backed with the required credit enhancement and security arrangements, including guarantees, insurance, and other risk mitigation instruments.

Independent Power Projects: An Analysis of Types and Outcomes

Many different forms of IPPs fall under the broad definition used in this study. They differ in their ownership and financing structures, in technology choices and risk profiles, in how they are procured and contracted, and in risk mitigation mechanisms. The analysis summarized here (as well as the main conclusions in chapter 5) is based primarily on case studies of five countries: Kenya, Nigeria, South Africa, Tanzania, and Uganda.

Among the case study countries, South Africa has embarked on the most ambitious renewable energy IPP program, which will soon be followed by thermal IPPs. Nigeria is undergoing the most extensive power sector reforms on the continent. Although other countries may not be able to replicate the experiences of these two major economies, many lessons from them can be adapted and applied. Tanzania and Kenya provide a fascinating opportunity to contrast the experiences and outcomes of solicited versus unsolicited bids.

Tanzania is also about to start more ambitious reforms and will expand its gas-to-power investments, while Kenya is encouraging a diversified set of power investments, including in renewable energy. Uganda has overhauled its electricity supply industry and has numerous small IPPs and the largest hydropower IPP in Sub-Saharan Africa.

Ownership, Financing Structures, and Development Finance Institutions

There has been a wide variety of African IPP sponsors and debt providers. State institutions have invested in some IPPs, but private sponsors are prominent, including private African partners, European entities such as Globeleq, Aldwych, and Wartsila, and numerous European bilateral DFIs. A smaller number of sponsors are from North America, Asia, and the Middle East. A few multilateral agencies also hold some equity.

In addition to equity investments, DFIs are prominent in the debt financing of IPPs. The African reality is one in which most IPPs carry substantial risks. Without DFI financing, key projects would not have reached financial close and commercial operation. DFIs have also reduced the chances of investments and contracts unraveling—in part because of rigorous due diligence practices, but also because of the pressure governments or multilateral institutions might bring to bear around honoring investment contracts.

Risk Mitigation

In addition to the customary risks, IPPs in the region are faced with risks that must be mitigated to make the investment viable. These are *political risk*—events resulting from adverse actions by the host government or from politically motivated violence; *regulatory risk*—any change in law or regulation that may have a negative impact on a project; and *credit/payment risk*—deficiencies in the credit quality and the payment capacity of the off-taker.

Mitigating these and other risks is crucial to attracting private investment to the Sub-Saharan African power sector. Various measures are available, but each context poses different challenges and requires tailored solutions.

In large projects in which the public sector plays a counterpart role, private investors routinely require *international arbitration* to resolve disputes. In particular, clauses addressing instances of a "change in law" or in sector regulations are commonly embedded in PPAs. When considering an investment in a new country, private sector investors often reach out to *the DFI community* to seek financing and other types of support for IPPs.

Where off-takers are not creditworthy or perceived as such, *sovereign guarantees* are the most common instrument to mitigate off-taker risks. In such cases, *structural measures* can also be designed to ring-fence revenues accruing to off-taker utilities and ensure that there is enough cash flow to honor payment obligations under the PPA. Another option to be considered is to transfer collection for a set of large, profitable customers from the utility to an escrow account managed by the IPP.

Although host governments can provide sovereign guarantees or arrange other risk mitigation measures, their capability to deliver on IPP commitments may remain in doubt. In that case, further risk mitigation instruments that transfer risks to third parties are in order. The most commonly used instruments are multilateral development bank guarantees, most often from the World Bank (but also more recently from the African Development Bank), and insurance products, in particular political risk insurance.

World Bank guarantees are designed to provide credit enhancement and direct risk mitigation. They are flexible in nature and adaptable to the specific requirements of each project and to market circumstances. Project-based World Bank guarantees may be *loan guarantees*, which mitigate the risks faced by commercial lenders with respect to debt service payment defaults, or *payment guarantees*, which mitigate the risks faced by private projects or foreign public entities with respect to payment default on government obligations not related to loans.

Insurance products may be provided by multilateral and bilateral agencies, export credit agencies, or private insurers. Guarantees and insurance are complementary products. Large and complex projects often involve both instruments.

The Sub-Saharan African experience clearly points to the fact that risk mitigation has been critical in attracting private investments to IPPs located in challenging markets and in keeping projects intact. (A few notable examples are presented in this study.) Going forward, risk mitigation promises to remain critical in attracting private financing to projects. Nevertheless, as IPP markets mature in Sub-Saharan Africa, it is possible that the use of risk mitigation arrangements will diminish. It is important to note that in no projects have guarantees of any sort been invoked, including in those projects whose contracts ultimately unraveled.

Technology Options: A Rise in Independent Power Projects Using Solar and Wind Energy

The last decade has witnessed a revolution in renewable energy technologies such as wind and solar energy, especially in the past five years as costs have fallen and efficiencies improved. The same has generally not occurred in fuel-to-power plants. Accordingly, for IPPs in the Sub-Saharan Africa power sector, grid-connected renewable energy is gaining traction.

The most dramatic example has been South Africa's recent large Renewable Energy Independent Power Project Procurement Programme (REIPPPP). Grid-connected wind and solar renewable energy in South Africa is now among the cheapest in the world. Outside South Africa, the wind story has been centered around a few projects in Kenya, which are marginally more expensive than Kenya's private geothermal capacity but beat any of the country's existing thermal plants on price.

Because both solar- and wind-based generation entail higher up-front costs and different risk profiles than those of traditional technologies, countries interested in renewables have experimented with methods to incentivize private investment.

Until recently, the most widely adopted procurement strategy for attracting renewable energy IPPs involved feed-in tariffs (FiTs), which have primarily been promoted by European bilateral aid programs. FiTs are beginning to face criticism, however, because prices have not come down as fast as those associated with competitive tenders. In Africa, the experience with this instrument has been disappointing, and relatively few projects have materialized.

However, two solar projects have been developed in Uganda under the global energy transfer feed-in tariff (GETFiT) program. This program was designed as a temporary facility to stimulate the small-scale renewable energy market, initially through a premium payment but also through firming up the contractual framework, providing investors with confidence, and extending institutional assistance to the host government. By early 2015, GETFiT had confirmed support for 15 projects with a total of 128 MW capacity. Although the results achieved to date in Uganda are less impressive than those in South Africa, these projects are still cheaper than the imported fuel-to-power alternative in Uganda.

Competitive Bidding versus Direct Negotiation

Excluding South Africa, direct negotiations outnumber competitive tenders across the Sub-Saharan Africa IPP pool and represent the majority of megawatts procured. Most often, direct negotiation originates in unsolicited proposals from interested investors. Historically, there has been no move toward or away from competitive tenders or directly negotiated projects; instead, there has been consistent engagement with both—again excluding South Africa.

Every one of the five study countries procured its first IPP by direct negotiation. In Kenya, Nigeria, and Tanzania, serious power shortages motivated the first IPP procurements. At the time, these countries had negligible experience with competitive procurement, and there was a general perception that direct negotiation would allow a quick fix. Most of these projects did come online rapidly, but later problems could be ascribed to their fast-track nature.

Subsequent private power projects in the five study countries have not followed a clear pattern. Both Kenya and Tanzania next used competitive procurement, as it was made a precondition for access to multilateral funding streams and guarantees. In these two countries, the initial negotiated IPPs were viewed as costly experiments. Meanwhile, Nigeria, South Africa, and Uganda continued to use direct negotiations to procure private power, despite the costs. Most recently, competitive tenders have finally emerged in South Africa and Uganda, and negotiated projects have returned in Kenya and Tanzania.

Overall, the level of competition in Sub-Saharan Africa has been disappointing. Nonetheless, the results are improving. Competitive tenders are most likely to bring about their intended benefits where they attract an adequate number of investors. With the exception of South Africa, no IPP tender in Africa has attracted more than a small handful of bidders, but there has been an increase over time.

Despite the relatively low number of bidders, the experience of the case study countries demonstrates that competitive procurement of IPPs provides clear price advantages. Some types of thermal generation are consistently less costly when competitively bid, although procurement of other thermal types appears to be comparable using either method. Wind projects, especially recently in South Africa, clearly show the advantage of competitive tenders over direct negotiation. Competitively bid solar projects in South Africa and Uganda are also more competitive than directly negotiated similar projects in Nigeria and Rwanda.

Despite the obvious benefits associated with competition, three arguments against competitive procurement are frequently made: (1) competitive tenders are more complex and expensive; (2) there is insufficient private investment interest to justify competitive tenders; and (3) the first developer or sponsor who conceives the project may be unwilling to compete via a tender because of proprietary data, technology, or the initial investment. These arguments are used mainly by private developers, but the first and second have also been used by public stakeholders to justify using direct negotiation rather than competitive bidding.

In reality, the record shows that while direct negotiations may appear to be simpler and cheaper at the outset, in practice they are often lengthy, and governments may be ill equipped to assess the value of unsolicited offers. Also, it is possible to run competitive bids efficiently and in short time frames. Although it is true that many tenders have attracted only a couple of bids, the solution is not direct negotiations—a public tender process opens any bid up to more scrutiny. A project can be made more attractive to investors by bundling it with other projects. Finally, several technical strategies are available to deal with investors who are reluctant to lose up-front capital or proprietary information via a competitive bid.

Competitive tenders are therefore preferable and countries should strive to use them. This does not mean that countries should never be involved in direct negotiations with unsolicited offers. In some instances, there could be few other options. Also, unsolicited proposals may lead to good deals, as long as countries are able to fully assess the value of the project, direct negotiations are run transparently, and countries have an adequate transaction capacity to negotiate reasonable PPAs. Transparency is even more important in the case of direct negotiations, as a means of minimizing the risk of controversy or corruption. Also, having in place a sound generation expansion plan is critical for assessing whether the project is the best option in terms of cost and technology choice. Therefore, countries need to invest in planning capacity, obtain transaction advisory support, and strive for transparency in their procurement practices.

Conclusions

Independent power projects make a significant contribution to meeting Africa's power needs. There is no doubt that IPPs are worth the effort. But it is not only the quantum of private investment in IPPs that is relevant; equally important are investment outcomes and, especially, the price and reliability of the electricity produced. The challenge ahead is for African countries to create the conditions to attract more and better IPPs and thus help overcome the continent's power deficit.

Competition still poses a conundrum in Africa, which is why this study pays particular attention to unpacking the trade-offs attached to competitive procurement. When procured competitively, IPPs have generally delivered power at lower costs than directly negotiated projects, and their contracts have held up better. Despite this, unsolicited and directly negotiated deals have been the norm across Sub-Saharan Africa, accounting for over 70 percent of all IPP megawatts procured.

After 20 years of reform efforts in Africa, nowhere on the continent is full wholesale or retail competition to be found in power sectors. Countries that have attracted the most finance have a wide range of sector policies, structures, and regulatory arrangements. In 13 such destinations for IPP investments, vertically integrated, state-owned utilities predominate. The presence of a regulator is also not definitive in attracting investment. Although the countries with the most IPPs all have formally independent regulators, some countries with regulatory agencies do not have any IPPs.

There seems to be no clear relation among reforms, degree of competition, and the success of countries to attract IPPs. Thus it is reasonable to ask what are the merits of competition in this context, and what are the key reform elements that can help African countries most advantageously attract IPPs? Responses to these questions may be condensed into five main conclusions:

- Systematic and dynamic power sector planning is crucial to identifying the generation projects that best meet a country's power needs and define the potential space for IPPs. Sound planning means that countries are able to project future electricity demand correctly, decide on best supply (or demand management) options, and anticipate how long it would take to procure, finance, and build the required generation capacity. Planning tools must be updated regularly and new building opportunities allocated based on clear criteria. Finally, there must be an explicit link between planning and the timely initiation of the generation procurement process.

- Competitive procurement of IPPs helps ensure that projects are implemented transparently and at the lowest cost. Two decades of experience in power procurement in Sub-Saharan Africa have amply demonstrated that a lack of competition in procuring new generation capacity has extensive drawbacks, ranging from immediate effects on project outcomes (higher prices, unraveling contracts, and so on) to more general effects on the overall governance of the electricity sector and its investment climate. IPP investment in Africa will rely on long-term contracts with off-takers where electricity demand is growing at medium or high rates. Where long-term contracts for new power are competitively bid rather than directly negotiated, there is a potential for reduced prices. Also, competitive procurement can stimulate the development of potentially bankable projects, especially renewable energy. African governments have not done enough to offer competitive tenders or auctions with clear ground rules; standardized, long-term contracts with IPPs; and reliable timelines. In the absence of these, project developers and funders have offered unsolicited bids. Designing and running competitive tenders are not trivial tasks. But if a core government team is authorized to do the work and sufficient resources are allocated for this purpose, then experienced transaction advisers can be hired to help. And the benefits of lower prices invariably justify the initial cost of running these tenders.

- Direct negotiations and unsolicited offers are not ruled out. Indeed, sometimes they are unavoidable, but governments that engage in unsolicited proposals or directly negotiated deals must develop the capacity to properly assess the cost-competitiveness of these projects and the technical and financial capabilities of the project developers—thereby negotiating cost-competitive contracts. In addition, unsolicited bids may be opened to more scrutiny by instituting a public tender.

- The financial viability of utilities is a critical factor in attracting IPP investments. IPP contracts should be undertaken with financially viable off-takers, whether they be utilities or large customers. Most IPPs are project-financed, and their bankability rests on secure revenue flows. Although credit enhancement and security measures can mitigate risk, a financially strong off-taker provides a sustainable basis for securing long-term contracts with IPPs. A sustained effort to better the performance of utilities must be at the center of countries' reform agendas and also be consistently supported by development partners through financial and technical assistance.

- Reforms, especially those improving the investment climate, remain important. Although IPP investment trends do not appear to be correlated with specific power sector institutional arrangements, the importance of reforms geared toward promoting a sound investment climate should not be discounted. Unraveling potential conflicts of interest between incumbent state-owned generators and IPPs, through unbundling generation from transmission, is in principle positive for private investment, as is more transparent contracting among state generators, IPPs, and independent transmission companies and system operators. Having a regulator in place is especially important, but the mere existence of a regulatory agency is not enough. The quality of regulation capacity is nonnegotiable: the regulator must be independent and endowed with competent—and sufficient—human resources.

In conclusion, investment in Africa's power sector IPPs is growing, but not fast enough. The region does not have sufficient power. All sources of investment need to be encouraged. For IPPs to flourish, the countries of Sub-Saharan Africa need dynamic, least-cost planning, linked to the timely initiation of the competitive procurement of new generation capacity. This must be accompanied by building an effective regulatory capacity that encourages the distribution utilities that purchase power to improve their performance and prospects for financial sustainability—and to widen access to electricity. Such efforts promise to promote economic and social development across the region.

Five Case Studies

1. Kenya's Electric Power Promise

Kenya is among the countries in Sub-Saharan Africa with the most extensive experience in IPPs. Its first IPPs date back to 1996, and since then the country has closed 11 projects for a total of approximately 1,065 MW and $2.4 billion in investment. Although these numbers are small from a global standpoint, IPPs will soon represent more than one-third of Kenya's total installed generation capacity. Despite this momentum, the actual process of procuring new power through IPPs has remained complex, and there are many opportunities for improvement.

The present situation should be viewed in the context of Kenya's reform efforts. Since the first reforms of the mid-1990s, there have been numerous changes in Kenya's electric power sector. An independent regulator was created in 1997. The Kenya Power and Lighting Company (KPLC, known as Kenya Power), which had served as an integrated utility since 1954, was unbundled. The KPLC began to focus exclusively on the transmission and distribution of electricity, while the Kenya Electricity Generating Company (KenGen) took over all public power generation activities. A second reform wave starting in 2004 saw the establishment of the Geothermal Development Company (GDC) to undertake an assessment of Kenya's geothermal resources, the creation of a new regulatory body, the Energy Regulatory Commission (ERC), and partial privatization of KenGen. In 2008, Kenya's "2030 Vision" set a new generation target of 23,000 MW by 2030, as well as other lofty goals. In 2013, an ambitious capacity expansion program was launched with the goal of bringing 5,000 MW online within 40 months. After spawning two large public projects that stalled, this program was scaled back.

Meanwhile, the ERC affirmed that IPPs would be given an opportunity to compete alongside KenGen, and a competitive market is a stated legislative goal. However, even with 11 current IPPs in Kenya, KenGen and the KPLC remain the dominant players in the country's power sector. There is no evidence that their roles in Kenya's hybrid market structure will be scaled back.

In recent projects, public and private procurements were said to be complementary, not competitive. To mobilize adequate funding for capacity expansion, those projects thought likely to attract private sector funding were offered to IPPs, all via international competitive bidding. Procurement, with the KPLC at the helm, has widely been considered to be positive, specifically in running effective competitive bids for thermal capacity. There was considerable competition for the three latest diesel generators, showing how much the sector has evolved since the late 1990s.

Alongside this evolution, problems persist in planning and procurement. Unlike many countries in Sub-Saharan Africa, Kenya has reasonably good mechanisms for the often-neglected process of planning for least-cost generation and transmission capacity. Unfortunately, since 2010 demand estimates from the government have been unrealistically high. Linked to this, a number of generation projects have been procured through direct negotiations and without a thorough technical and financial analysis to determine whether the proposed plants meet least-cost planning standards.

Because of the variety of projects, Kenya offers an interesting opportunity to compare directly the performance of state-owned power plants with IPPs using similar technologies. Plant availability is arguably the best performance indicator. IPP diesel projects have outperformed their public sector equivalents.

Although the data on plant availability demonstrate the technical superiority of IPPs, electricity price data favor KenGen. The comparison, however, is affected by differences in capital costs. The two KenGen diesel plants are more price competitive than most IPP diesel plants. However, one particular IPP diesel plant is the cheapest of all; it has a heat-recovery system, which improves efficiency, and it is located close to its fuel source. Among geothermal plants, most of the publicly owned KenGen plants are relatively more competitive.

In summary, for two decades private and public power projects in Kenya have been developed in parallel. Private developers have been critical in mobilizing funding to meet the nation's demand for electricity, and they have complemented publicly owned projects. Kenya's power-planning process has been dynamic, and there has been a strong track record of international competitive bidding. However, more recently the planning process has not always been based on solid independent technical analysis. Overall, Kenya has demonstrated the clear advantages of competitive bidding for thermal plants, and also the cost advantages of renewable energy, particularly geothermal power. After two decades of experience, the key remains the careful implementation of IPPs, from planning to competitive procurement to effective contracting.

2. Independent Power Projects and Power Sector Reform in Nigeria

Nigeria represents a fascinating case of accelerating investment in new power capacity in an electricity sector undergoing radical reform. Although Nigeria has the largest population and economy on the African continent, 46 percent of its citizens live below the poverty line and less than 50 percent have access to electricity. The demand for electricity far outweighs available capacity, which is less than 5 GW for a population of about 170 million. Making matters worse, the actual generation output in Nigeria is far below installed capacity. Nigeria's output rate per capita is among the lowest in the world, owing to poor operation and maintenance, aging generation and transmission infrastructure, fuel supply constraints, and vandalism.

Nonetheless, since 2001 Nigeria has embarked on the most ambitious electricity sector reform effort of any country in Africa. As part of the reform process, Nigeria has unbundled the generation, transmission, and distribution subsectors; privatized power generation stations and distribution utilities; appointed a private management contractor to manage the transmission company; and established a bulk trader. Other than South Africa, Nigeria also boasts the largest investment in IPPs in Sub-Saharan Africa.

Several generations of IPP transactions correlate with distinct phases of the sector reform process. Today, however, a new power market is being established, and a fourth generation of classic, project-financed IPPs is emerging. IPP contracts have had to be designed and negotiated afresh in the new market conditions, and appropriate credit enhancement and security measures have had to be put in place to mitigate payment and termination risks.

The challenges and risks of reform in Nigeria have been formidable. Each step has prompted new issues that have required further interventions. Nigeria has not waited for all steps to be clearly defined and agreed upon before moving. Instead, the "Nigerian way" has been to catalyze strong momentum for reform that becomes difficult to reverse and that forces political decisions and interventions along the way. It is not clear whether the "Nigerian way" will sustain the reforms. Election-related pressure to reduce tariffs did not help, and financial sustainability has yet to be demonstrated.

Nigeria has seen recent investments in power generation capacity. The largest source of new generation to date has been publicly funded projects that are being privatized, but historically there also have been significant investments in IPPs, and recently a large IPP investment closed. Indeed, excluding South Africa, Nigeria has more privately funded megawatts than any other country in Sub-Saharan Africa. Also noteworthy in Nigeria has been the entry of Asian power investors in the form of the Republic of Korea's KEPCO (Korea Electric Power Corporation) and the Chinese engineering, procurement, and construction contractors. However, even these investments are not sufficient to meet Nigeria's power needs.

Interestingly, the first wave of IPP investments preceded power sector reforms. And the most recent IPP power purchase contracts were signed during a period of financial uncertainty. Incomplete reforms and financial shortfalls in the sector have thus not blocked IPP investments. However, not many countries would have been able to divert massive financial allocations (in Nigeria's case, from oil revenues) to keeping electricity companies afloat. Without serious efforts to achieve financial sustainability in the industry, private investments will be at risk.

Nigeria does not yet have a benchmark for international competitive bids versus directly negotiated projects. However, the government regulator has mandated competitive tenders by a rule published in 2014. It is hoped that the contracting authority (the electricity bulk trader) will commence international competitive tenders in the near future.

Nigeria also does not yet have any grid-connected renewable energy projects (other than hydropower), but some solar photovoltaic projects in the pipeline are being negotiated by the bulk trader. Preparatory work is being undertaken for competitive bids for renewable energy. In a few years' time, it will be worthwhile to compare these price outcomes with those of directly negotiated projects.

It is also hoped that capacity will be built for effective generation planning and that the system operator will issue regular demand and supply forecasts that will trigger initiatives to procure new capacity. Regular and dynamic generation expansion plans—linked directly to competitive procurement and effective contracting—are needed.

What are the lessons for other African countries? Clearly, the extensive power sector reforms in Nigeria have not been a panacea. Few other African countries have sought to completely unbundle and privatize their entire electricity sector, and not one has set up a wholesale electricity trader. Nonetheless, Nigeria has demonstrated that it is possible to attract IPPs in a challenging investment climate. There, IPPs have been built more quickly than publicly funded projects, and data also show that the performances of IPPs have been superior to those of state-owned generation plants, although the more reliable gas supplies of IPPs probably contribute to the difference.

The poor financial performance of Nigeria's distribution companies and the insecurity of gas supplies have added risk to new IPP investments—risks that have had to be mitigated through extensive credit enhancement and security measures. Other African countries with risky investment climates can learn from what has been required in Nigeria, but it is hoped that the extent and cost of these risk mitigation instruments will fall over time as the financial sustainability of the sector improves. And herein is a key lesson: ultimately, IPP investments rely on secure revenue flows from customers and distribution companies. There is no way to avoid the fundamental challenge of improving the technical and commercial performance of electricity distribution utilities. Indeed, the future success of Nigeria's power sector reforms and investment program depends on it.

3. Investment in Power Generation in South Africa

South Africa is a latecomer to introducing private investment and IPPs into its electricity sector. Two areas have been the focus of reform efforts in South Africa's power sector over the last two decades: (1) restructuring the fragmented electricity distribution industry, and (2) unbundling the national electricity utility, Eskom, to facilitate private investments in electricity generation. However, on neither front has there been much progress. And yet, although past attempts to introduce IPPs were halfhearted and unsuccessful, today this situation has changed dramatically in the area of renewables.

Most notably, South Africa now occupies a central position in the global debate on which are the most effective policy instruments to accelerate and sustain private investments in renewable energy. The government's current program, REIPPPP, has successfully channeled substantial private sector expertise and investments into grid-connected renewable energy at competitive prices. To date, 92 projects have been awarded to the private sector, and the first projects are already online. Private sector investments of more than $19 billion have been committed for projects that total 6,327 MW of renewable energy. Over only four years, 2011–15, the prices of renewable energy dropped during four bidding phases, with average solar photovoltaic tariffs decreasing by 71 percent and wind dropping by 48 percent.

Until recently, South Africa was Africa's largest economy. Its electricity generation amounts to more than half of the installed capacity in all of Sub-Saharan Africa. South Africa's electricity supply industry is dominated by its state-owned and vertically integrated utility, Eskom. With a capacity of approximately 42 GW, Eskom generates approximately 96 percent of the country's electricity. Eskom also owns and controls the high-voltage national transmission grid and supplies approximately half of the electricity generated directly to customers. The other half is distributed through 179 municipalities.

South Africa has a well-defined, rigid electricity planning and procurement system. Until 2006, Eskom assumed sole responsibility for electricity planning and procuring new generation capacity. Legislation changed this situation, however, giving responsibility to the minister of energy to produce regular Integrated Resource Plans that guide electricity generation investments. In practice, Eskom's staff continues to produce the Integrated Resource Plans, but they do so now under the guidance and approval of the energy ministry.

Initially, Eskom was charged with procuring IPPs, but, facing an obvious conflict of interest with its own generation ambitions, it failed to contract adequate amounts of privately produced power. The ministry began assuming responsibility for IPPs, but it realized early on that it did not have the capacity to run large, sophisticated power procurement programs (PPPs). It therefore welcomed the assistance of experienced PPP advisers in the National Treasury and, along with an army of local and international transaction advisers, designed and ran what is now widely recognized and applauded as a world-class, albeit ad hoc, procurement group.

South Africa's experience suggests several key lessons for successful renewable energy programs in other emerging markets. For example, it is evident that private sponsors and financiers are more than willing to invest in renewable energy if the procurement process is well designed and transparent, transactions have reasonable levels of profitability, and key risks are mitigated by the government. Renewable energy costs are falling, and technologies such as wind turbine electric generation are becoming competitive with fossil fuel generation. Furthermore, renewable energy procurement programs have the potential to leverage local social and economic development. The REIPPPP also highlights the need for effective program champions with the credibility to convincingly interact with senior government officials, effectively explain the program to stakeholders, and communicate and negotiate with the private sector.

Other interesting lessons from South Africa are related to public versus private projects. In the case of renewable energy, competitive tenders and private sector developers produced better price outcomes and shorter construction times than the national utility, which had had no prior experience with renewable energy. South Africa's experience also demonstrates that much greater competition is possible among renewable energy providers—93 bids were received in the third round—than thermal power plants. The smaller project sizes, diversified and distributed renewable energy resources, and a highly competitive international market of project developers, equipment suppliers, and finance sources facilitate competition.

Furthermore, South Africa's experience highlights that significant investments in new electricity generation capacity are possible in a power sector that has undergone only limited reforms. Although an independent regulator has been established and IPPs are permitted, the vertically integrated and state-owned Eskom has retained a dominant market position. However, the current power crisis in South Africa suggests that further reform is required. Unbundling generation and leaving Eskom with system and market operation, transmission, and perhaps also distribution could focus scarce management skills, improve efficiencies, and create a level playing field between public and private investments in generation. Planning, procurement, and contracting functions could be embedded in a nonconflicted Eskom. These are the key concerns in any sector reform or restructuring. Ultimately, successful power sector reforms are not about ownership or wholesale or retail competition as much as they are about the effectiveness of planning, procuring, and contracting new investments.

4. Power Generation Results Now, Tanzania!

Tanzania has a vast array of conventional and renewable energy resources, including recently discovered significant offshore gas reserves. And yet the country struggles to generate sufficient power to fuel growth and development. It has only 1,583 MW in installed generation, and imported fuel is a critical piece of its electric power generation. Network failures undermine what little power is produced. As a result, approximately 46 percent of the nation's total power consumption is from off-grid self-generation.

The government's current plan to address these problems has set admirable and ambitious goals of achieving 10,000 MW of generation capacity by 2025, doubling access rates, increasing efficiency, boosting transparency and financial integrity, and privatizing generation and distribution assets. But viewed in light of the recent past, it is uncertain whether the government has the requisite capacity to deliver on these objectives. It has repeatedly committed to reforms, but has been slow to implement them and has wavered in its commitment to integrate private power sustainably and systematically. Notwithstanding ambitious reforms envisioned for the electricity sector, its present structure continues to be characterized by the prominence of nontransparent deals and by a poor-performing, vertically integrated, state-owned utility, the Tanzania Electric Supply Company (TANESCO, whose attempts to contract IPPs are sporadic and not always successful).

Several specific projects illustrate Tanzania's difficulties. The potential of recently discovered gas reserves to change the landscape of Tanzania's electric power production has not yet been fulfilled. The absence of relevant planning and timely implementation (including the development of pipeline and gas processing infrastructure) along with a weak investment climate have prevented Tanzania from exploiting its gas potential. Delays in expanding the gas supply have already resulted in costly contingency plans such as emergency power projects (EPPs), which in turn have bankrupted TANESCO. These EPPs, along with one ill-fated thermal IPP, Independent Power Tanzania Ltd. (IPTL), account for an inordinate portion of costs relative to actual production, due in large part to imported fuel charges.

The lessons from Tanzania's experience with IPTL, detailed in this study, could not be more explicit. When power is not planned, procured, and contracted transparently and consistently, the implications are potentially grave, far-reaching, and ongoing. Rather than being considered a planning and procurement mishap, however, IPTL is often used to emphasize the drawbacks of private sector participation. Meanwhile, Songas, a more successful Tanzanian IPP, has not been widely recognized as an example of how competitive procurement and private sector involvement can work together to harness more power. Instead, Songas has been charged with having advanced private interests at the expense of the state, including obtaining key assets such as pipeline infrastructure that are in the strategic interests of the country.

The wind story in Tanzania provides evidence that the lessons of the IPTL debacle have not been internalized by key stakeholders. Various factions still compete within state agencies, based on vested interests, and transparency remains compromised, despite efforts to empower the national regulator.

The issues at stake go beyond the question of private versus public sector involvement, however. The lack of competitive procurement and transparent contracting has resulted in costly deals and disputed contracts, with large drains on time and resources lost. The national regulator has been given the mandate to reject unsolicited proposals that are not within the Power Sector Master Plan and are not financially viable. However, negotiated deals persist, and noncompetitive procurement remains the preferred method at the governing level. Incoherent planning and interagency disagreements have compounded the problem and impeded the timely procurement of generation. As a result, the country has been forced to depend on EPPs and expensive oil-fired generation over the last several years.

It is hoped that a secure gas supply will be established, putting an end to Tanzania's costly dependence on imported fuel. Private power has, largely through Songas, helped benchmark the state-owned utility, raised the bar, and provided critical new generation. Other projects, such as IPTL and the EPPs, have proven to be costly experiments, primarily because of planning and procurement failures. Tanzania deserves a new decade of private and public project successes.

5. Power Generation Developments in Uganda

Uganda occupies a unique space in the history of power sector reform and investment in Africa. It was the first country to unbundle generation, transmission, and distribution into separate utilities and to offer separate, private concessions for power generation and distribution. Critics said that Uganda's power system was too small to reap the possible benefits that might flow from competition in generation and more focused management of transmission and distribution. The years that immediately followed the reforms seemed to bear out the critics' views: the private distribution operator struggled to reduce losses, and there were delays in investments in large new hydropower capacity, resulting in costly dependence on short-term thermal power.

Despite ongoing challenges, Uganda's power sector reforms are now bearing fruit. The performance of the distribution utility has improved. Losses are down, and collections, investment, and connections are up, although access rates remain low. After a torturous start, Uganda concluded the largest private hydropower investment in Africa built by an IPP, Bujagali. Simultaneously, it has attracted a raft of smaller IPP investments, including innovative competitive bids for small hydropower, biomass, and solar projects solicited under the GETFiT program. After South Africa, Uganda has the largest number of IPPs in Sub-Saharan Africa and the only other competitively bid, grid-connected solar photovoltaic program.

Uganda's experience in IPP development is among the most interesting in Africa. By 2012, it had implemented 11 IPP projects across a diverse set of generation technologies and project capacities. Between 2015 and 2018 it is expected that up to 20 small-scale (1–20 MW) projects will be added to this portfolio through the government's cooperation with the German Development Bank on the GETFiT Uganda program. And with an estimated total investment volume of $860 million and a capacity of 250 MW, Bujagali ranks among the largest privately financed hydroelectric power projects in Sub-Saharan Africa.

Alongside these IPP successes, Uganda has now embarked on two large Chinese-funded hydropower projects. While locally IPPs are seen to be potentially expensive, complex, and time-consuming, investors rank Uganda as one of the top destinations for private sector investment in renewable energy technologies.

In general, it can be said that the Ugandan government has been successful in achieving its development goals for the power generation sector. With close to 1,000 MW under implementation or in later feasibility stages, the capacity under development has multiplied within a short time frame of three years. Uganda has also managed to develop a mix of public projects financed by Chinese sources and privately financed small-scale IPP projects—a mix that is unique in Sub-Saharan Africa. Large hydropower projects accounted for 74 percent of Uganda's power capacity in 2013, followed by thermal plants (12 percent). Bagasse and small hydropower projects supplied roughly equal shares of the remainder. Electricity production in 2013 was split more or less evenly between IPPs (1.492 GWh) and public projects (1.291 GWh), with a small share of thermal capacity, currently operated as emergency or standby capacity. IPP production increased dramatically with the commissioning of the Bujagali hydropower plant in 2012, which reduced the need for emergency power generation.

The Ugandan government intends to follow a two-pronged policy for procuring generation capacity in the years to come. For large-scale projects, international competitive bidding seems to have been abandoned in favor of direct awards to international—effectively Chinese—contractors. At the small to medium end of the scale, targeted policies aim to further encourage foreign investment in IPP projects involving all types of generation.

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Abbreviations

ADFD	Abu Dhabi Fund for Development
AFD	Agence Française de Développement
AfDB	African Development Bank
AFESD	Arab Fund for Economic and Social Development
AFUDC	allowance for funds used during construction
AFUR	African Forum for Utility Regulators
AGFA	Associated Gas Framework Agreement
AGIP	Azienda Generale Italiana Petroli
AICD	Africa Infrastructure Country Diagnostic
AIIF	African Infrastructure Investment Fund
ANEEL	Brazilian Electricity Regulatory Agency
ATI	African Trade Insurance Agency
BADEA	Arab Bank for Economic Development in Africa
BNDES	Brazilian Development Bank
BNEF	Bloomberg New Energy Finance
BOAD	West African Development Bank
BOO	build-own-operate
BOOT	build-own-operate-transfer
BOT	build-operate-transfer
BPE	Bureau of Public Enterprises
BRICS	Brazil, Russian Federation, India, China, and South Africa
BRN	Big Results Now
BWSC	Danish engineering company (owned by Mitsui)
CAPEX	capital expenditure
CAR	Central African Republic
CBAO	Banking Company of West Africa
CBN	Central Bank of Nigeria
CCGT	combined-cycle gas turbine
CDC	Commonwealth Development Corporation

CEC	Copperbelt Energy Corporation
CEO	chief executive officer
CGC	China Geo-Engineering Corporation
CGGC	China Gezhouba Group Company
CIDA	Canadian International Development Agency
CIPREL	Compagnie Ivoirienne de Production d'Électricité
CMEC	China Machinery Engineering Corporation
COD	commercial operation date
CPI	consumer price index
CSP	concentrated solar power
CTL	Centrale Thermique de Lomé
DA	direct agreement
DAC	Development Assistance Committee (of the OECD)
DARESCO	Dar es Salaam and District Electric Supply Company
DBSA	Development Bank of Southern Africa
DEG	German Investment and Development Corporation
DFI	development finance institution
DfID	U.K. Department for International Development
DisCo	distribution company
DN	direct negotiation
DoE	Department of Energy
DPC	dynamic production cost
DPE	Department of Public Enterprises
DPO I-II	Development Policy Operation Credits I and II
DSCR	debt service coverage ratio
EADB	East African Development Bank
EAIF	Emerging Africa Infrastructure Fund
EAPP	Eastern Africa Power Pool
ECA	Excess Crude Account
ECG	Electricity Company of Ghana
EDI	Electricity Distribution Industry
EIA/U.S. EIA	U.S. Energy Information Administration
EIB	European Investment Bank
EKF	Eksport Kredit Fonden (Danish export credit agency)
EoI	expression of interest
EPC	engineering, procurement, and construction
EPE	Brazilian Energy Research Agency
EPP	emergency power plant
EPSRA	Electric Power Sector Reform Act

ERA	Ugandan Electricity Regulatory Authority
ERB	Electricity Regulatory Board
ERC	Energy Regulatory Commission
ERR	economic rate of return
ESAP	environmental and social action plan
ESIA	environmental and social impact assessment
ETG	Export Trading Group
EWURA	Tanzanian Energy and Water Utilities Regulatory Authority
FDI	foreign direct investment
FEC	Firm Energy Certificate
FIRR	financial internal rate of return
FiT	feed-in tariff
FMO	Netherlands Development Finance Company
FY	fiscal year
GDC	Geothermal Development Company
GDP	gross domestic product
GenCo	generation company
GETFiT	global energy transfer feed-in tariff
GIIP	gas initially in place
GoT	Government of Tanzania
GoU	Government of Uganda
GSA	government support agreement
GW	gigawatt
GWh	gigawatt-hour
HFO	heavy fuel oil
HPP	hydropower plant
IA	implementation agreement
IBRD	International Bank for Reconstruction and Development (of the World Bank Group)
ICB	international competitive bid
ICBC	Industrial and Commercial Bank of China
ICSID	International Centre for Settlement of Investment Disputes
IDA	International Development Association (of the World Bank Group)
IDC	Industrial Development Corporation
IEA	International Energy Agency
IFC	International Finance Corporation (of the World Bank Group)
IFU	Danish Investment Fund for Developing Countries
IGG	Inspectorate General of Government

IMF	International Monetary Fund
IOC	international oil company
IPP	independent power project
IPS	Industrial Promotion Services
IPS-AKFED	Industrial Promotion Services-Aga Khan Fund for Economic Development
IPTL	Independent Power Tanzania Ltd.
IRENA	International Renewable Energy Agency
IRP	Integrated Resource Plan
IsDB	Islamic Development Bank
ISMO	independent system and market operator
ISO	independent system operator
JIBAR	Johannesburg Interbank Agreed Rate
JICA	Japan International Cooperation Agency
KenGen	Kenya Electricity Generating Company
KEPCO	Korea Electric Power Corporation
KETRACO	Kenya Electricity Transmission Company
KfW	Kreditanstalt für Wiederaufbau (German development bank)
KILAMCO	Kilwa Ammonia and Urea Company
km	kilometer
km^2	square kilometer
KNEB	Kenya Nuclear Electricity Board
KPDC	Kribi Power Development Company
KPLC	Kenya Power and Lighting Company
K Sh	Kenya shilling
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LC	letter of credit
LCOE	levelized cost of energy
LCPDP	Least Cost Power Development Plan
LEC	Lesotho Electricity Company
LNG	liquefied natural gas
LRF	livelihood restoration framework
LRMC	long-run marginal cost
LTWP	Lake Turkana Wind Project
m^3/s	cubic meters per second
MBLIPP	Multisite Baseload Independent Power Project

MDB	multilateral development bank
MEGS	Mediterranean Electric Generating Services
MEM	Ministry of Energy and Minerals
MEMD	Ministry of Energy and Mineral Development
MEP	Mtwara Energy Project
MFI	multilateral finance institution
MHI	Manitoba Hydro International
MIGA	Multilateral Investment Guarantee Agency (of the World Bank Group)
MMBtu	million British thermal units
MME	Minister of Mines and Energy
mmscf	million standard cubic feet
mmscfd	million standard cubic feet per day
MoE	Ministry of Energy
MoEP	Ministry of Energy and Petroleum
MoU	memorandum of understanding
MSD	medium-speed diesel
MTPPP	Medium-Term Power Purchase Programme
MW	megawatt
MWh	megawatt-hour
MYTO	Multi-Year Tariff Order
NBET	Nigerian Bulk Electricity Trading
NCP	National Council on Privatisation
NDC	National Development Corporation
NELMCO	Nigeria Electricity Liability Management Company
NEMS	Nigerian Electricity Market Stabilization
NEPA	National Electric Power Authority
NERC	Nigerian Electricity Regulatory Commission
NERSA	National Energy Regulator of South Africa
NIPP	national integrated power project
NNGIP	National Natural Gas Infrastructure Project
NNPC	Nigerian National Petroleum Corporation
NORAD	Norwegian Agency for Development Cooperation
Norfund	Norwegian Investment Fund for Developing Countries
NPV	net present value
O&M	operations and maintenance
OCGT	open-cycle gas turbine
ODA	official development assistance

OECD	Organisation for Economic Co-operation and Development
OFID	OPEC Fund for International Development
OPEC	Organization of the Petroleum Exporting Countries
OPIC	Overseas Private Investment Corporation
PACP	Presidential Action Committee on Power
PAP	Pan Africa Power Tanzania Ltd.
PAT	PanAfrican Energy Tanzania Ltd.
PCG	partial credit guarantee
PHCN	Power Holding Company of Nigeria
PLF	plant load factor
PNCP	Pilot National Cogeneration Programme
PPA	power purchase agreement
PPDA	Public Procurement and Disposal of Public Assets Act
PPI	Private Participation in Infrastructure
PPP	power procurement program; public-private partnership; purchasing power parity
PRG	partial risk guarantee
PRI	political risk insurance
PSA	production-sharing agreement
PSIP	Power Sector Investment Plan
PTA	Preferential Trade Area Bank
PTFP	Presidential Task Force on Power
PURA	Petroleum Upstream Regulatory Authority
PV	photovoltaic
QPEA	Quantum Power East Africa
R	South African rand
RAP	Resettlement Action Plan
Rc	rand cent
REA	Kenya Rural Electrification Authority; Tanzania Rural Energy Agency; Uganda Rural Electrification Agency
RED	regional electricity distribution company
REEEP	Renewable Energy and Energy Efficiency Partnership
REFiT	renewable energy feed-in tariff
REIPPPP	Renewable Energy Independent Power Project Procurement Programme
REP	Rural Electrification Programme
RET	renewable energy technology
RfP	request for proposals
RfQ	request for qualification

RMB	Rand Merchant Bank
ROE	return on equity
S&P	Standard & Poor's
SAEMS	South Asia Energy Management Systems
SBLC	standby letter of credit
SCB-HK	Standard Chartered Bank, Hong Kong
SENELEC	Société Nationale d'Électricité du Sénégal
SHP	small hydropower plant
Sida	Swedish International Development Cooperation Agency
SOE	state-owned enterprise
SPE	Society of Petroleum Engineers
SPP	small power project
SPV	special-purpose vehicle
SSA	Sub-Saharan Africa
STPPP	Short-Term Power Purchase Programme
T&D	transmission and distribution
TANESCO	Tanzania Electric Supply Company
Tcf	trillion cubic feet
TCN	Transmission Company of Nigeria
TDFL	Tanzania Development Finance Company Limited
TDV	Tanzania's Development Vision
TEM	Transitional Electricity Market
TPC	Tanganyika Planting Company
TPDC	Tanzania Petroleum Development Corporation
UAE	United Arab Emirates
UEB	Uganda Electricity Board
UEDCL	Uganda Electricity Distribution Company Ltd.
UEGCL	Uganda Electricity Generation Company Ltd.
UETCL	Uganda Electricity Transmission Company Ltd.
USc	U.S. cent
VAT	value added tax
VRA	Volta River Authority
WB	World Bank
WBG	World Bank Group
WEPS	Wholesale Electricity Pricing System
YFP	Yinka Folawiyo Power

All dollar amounts are U.S. dollars unless otherwise indicated.

PART 1

Power Generation in Sub-Saharan Africa

CHAPTER 1

Introduction

The Challenges Faced by Sub-Saharan Africa's Power Sector

All too often the dismal statistics and track record of Sub-Saharan Africa's power sector are cited. Two out of three households in Sub-Saharan Africa, close to 600 million people, have no electricity connection at all. Electrification rates are highest in South Africa (around 88 percent), followed by Nigeria, Côte d'Ivoire, Senegal, Cameroon, Gabon, Ghana, and Botswana (all above 50 percent). But most Sub-Saharan African countries have pitifully low access rates. Rural areas remain the most underserved in the world: in some countries, less than 5 percent of the rural population has access to electricity. Although electricity consumption levels in Sub-Saharan Africa have accelerated over the past decade, they are, on average (and excluding South Africa), less than 2 percent of the average level seen in the Organisation for Economic Co-operation and Development (OECD) countries (U.S. EIA 2014; IEA 2014b).

Chronic power shortages combined with inadequate transmission and distribution networks are primary causes of low electricity access and consumption. Many countries simply do not have enough electricity to distribute to potential consumers. The region's entire installed capacity, at a little over 80 gigawatts (GW), is equivalent to that of the Republic of Korea; excluding South Africa, this total is less than 40 GW. Nigeria, with more than three times South Africa's population, has only 15 percent of its installed generation capacity. Meanwhile, across Sub-Saharan Africa, per capita installed generation capacity is barely one-tenth that of Latin America.

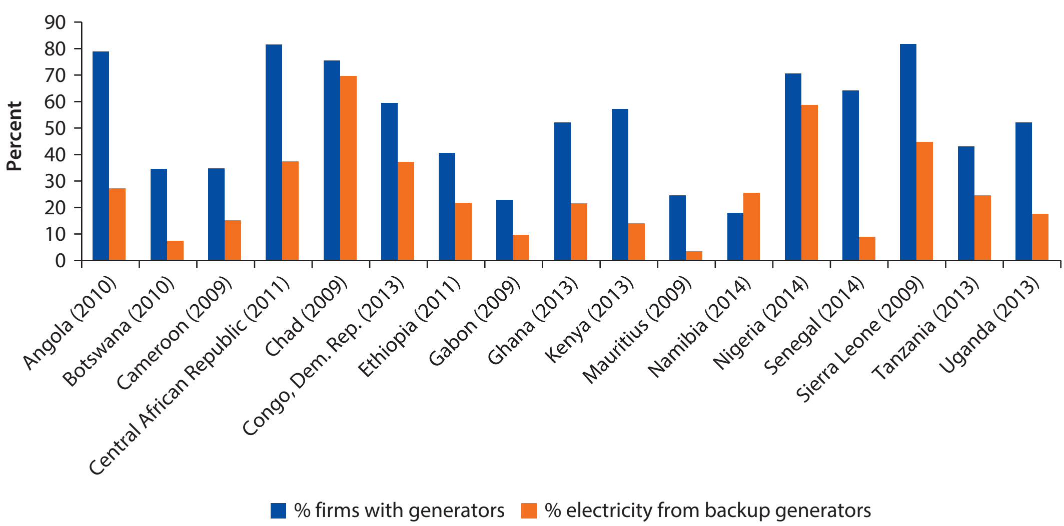
The World Bank's Africa Infrastructure Country Diagnostic (AICD) quantified the extent to which existing power systems are unable to adequately meet suppressed demand, generate sufficient electricity for economic growth, and increase new connections to boost access to electricity (Eberhard and others 2011). Using 2005 as a baseline, the Bank estimated that Sub-Saharan Africa needed to add approximately 8 GW of new generation capacity each year through to 2015 to meet suppressed demand, keep pace with projected economic growth, and support the rollout of further electrification in line with poverty reduction targets, compared with the 1–2 GW added on average annually in the past decade (Eberhard and others 2011: 58).

The majority of countries in Sub-Saharan Africa have experienced power shortages over the past few years, resulting in load shedding and frequent interruptions to service. The economic costs of power outages, including the costs of running backup generators and of forgone production, typically range between 1 and 4 percent of gross domestic product (GDP) (Foster and Briceño-Garmendia 2010). It is estimated that infrastructure problems and, notably, deficient power generation and transmission infrastructure account for 30–60 percent of overall drains on firm productivity—well ahead of red tape, corruption, and other factors (Escribano, Guasch, and Pena 2008). The region's high reliance on backup generators, shown in figure 1.1, is an indication of the inadequacy and unreliability of grid-supplied power.

Poor electricity supply is generally the result of inadequate investment in new power generation capacity; the deteriorating performance of existing power plants may also play a part. South Africa's recent power outages, for example, have been exacerbated by plant breakdowns at its national utility, Eskom, and a resulting decline in available power (figure 1.2).

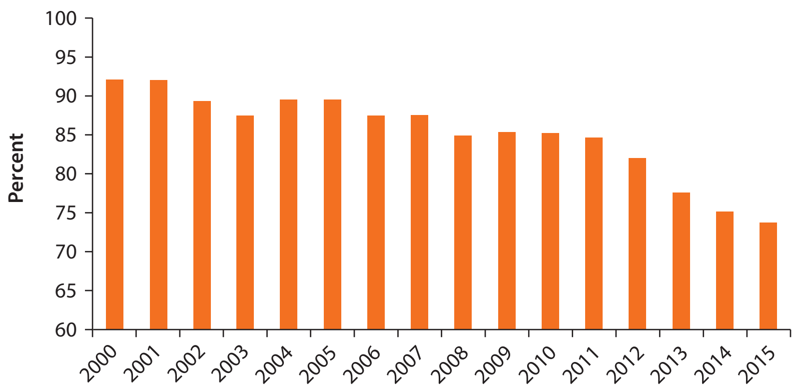
In the case of state-owned utilities, maintenance and operations have often been poor, and tariffs and collections have been insufficient to support the refurbishment of equipment or new investments. Even though many countries permit private sector participation in generation, shortcomings in planning and procurement have been common, and international competitive tenders for new capacity have been few and far between.

Figure 1.1 Percentage of Firms Relying on Generators: Selected Countries in Sub-Saharan Africa, Various Years



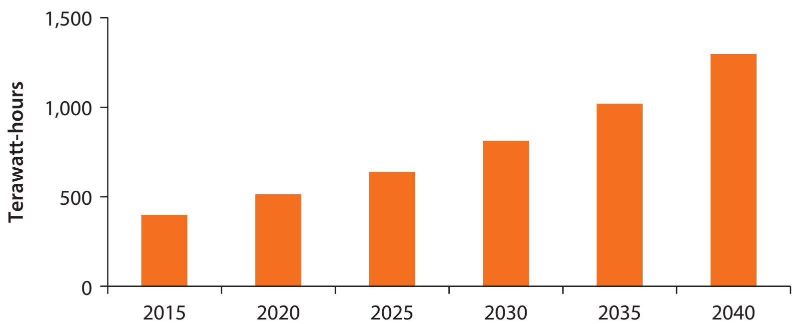
Source: World Bank 2014.

Figure 1.2 Average Availability of Generation Plants Run by Eskom: South Africa, 2000–15



Source: Eskom annual reports.
Note: Unit capacity factor is defined as the amount of electricity generated by a power unit or power station throughout a specified time period, divided by the maximum amount of electricity that the plant could have generated during that period—that is, the installed capacity multiplied by the number of hours in that period, expressed as a percentage.

Figure 1.3 Projected Electricity Demand: Sub-Saharan Africa, 2015–40



Source: IEA 2014a.

Looking ahead, Africa will need to ramp up its power generation capacity. Expanding electricity supply is even more important in the face of economic growth on the continent, which has been the key driver of electricity demand in the past decade.

The International Energy Agency (IEA 2014a) predicts that electricity demand in Sub-Saharan Africa will increase at a compound average annual growth rate of 4.6 percent, and by 2030 will be more than double its current electricity production (figure 1.3). The need for large investments in expanding power generation capacity is self-evident.

The cost of addressing Sub-Saharan Africa's power sector needs has been estimated at $40.8 billion a year, equivalent to 6.35 percent of Africa's GDP. Approximately two-thirds of this is needed for capital investment ($27.9 billion a year); the remainder is for operations and maintenance (O&M). Of capital expenditure, about $14.4 billion is required for new power generation each year, and the remainder for refurbishments and networks (Eberhard and others 2011: 60). Existing investment is far below what is needed.

Importance of Private Sector Participation and the Role of Independent Power Projects

The large funding gap that holds back investments in new power projects in Africa cannot be bridged by the public sector alone. Private participation is critical. Historically, most of such private sector financing has been channeled through independent power projects (IPPs), intended as nonutility generators that sell power to public utilities, end consumers, or wholesale power traders. Box 1.1 presents the definition of IPPs used in this study and their various types.

IPPs are not uniform. Although the typical IPP structure is understood as a privately sponsored project with nonrecourse or limited recourse project financing, some IPPs in Sub-Saharan Africa do not follow this exact model. Instead, the government may hold some portion of equity and/or debt, bringing IPPs closer to a model of a public-private partnership (PPP) than that of a traditionally conceived IPP. Examples of even more pronounced departures from what might be expected include the Itezhi-Tezhi hydropower plant (HPP) in

Box 1.1 Definition of Independent Power Projects

In this book the definition of independent power projects (IPPs) is slightly broader than that of traditional private power projects that rely on nonrecourse or limited recourse project finance. Some of the projects categorized as IPPs in this study are financed by corporations; others are supported in part by public funding.

For the purposes of this study, IPPs are defined as power projects that are, in the main, privately developed, constructed, operated, and owned; have a significant proportion of private finance; and have long-term power purchase agreements with a utility or another off-taker.

Within this overall definition, various IPP typologies may be identified, based on:

- *Ownership and financing structures*. Private or corporate-financed projects, or joint venture companies with minority public funding, and different debt/equity ratios.
- *Technology*. Thermal or renewable energy projects, using different technologies and sources, including diesel, heavy fuel oil, geothermal, hydropower, solar, wind, and biomass.
- *Procurement modalities*. Projects that have been competitively procured or are unsolicited or directly negotiated.
- *Financial and risk mitigation structures*. Projects that benefit from different risk mitigation, credit enhancement, and security arrangements.

Emergency power, in the form of temporary lease agreements, is excluded from these categories.

Zambia, 50 percent of which is owned by the state-run utility, ZESCO; and the second wave of IPPs in Nigeria (that is, IPPs that were developed on the balance sheet of their sponsors), in which the Nigerian National Petroleum Corporation has a 60 percent ownership stake. State-run companies—the Tanzania Electric Supply Company (TANESCO), Tanzania Petroleum Development Corporation (TPDC), and Tanzania Development Finance Company Limited (TDFL)—all hold equity in Songas, Tanzania's flagship gas-to-electricity project. And there are other variations on the traditional IPP model. For example, instead of receiving commercial project financing, numerous IPPs have been the beneficiaries of funding by development finance institutions (DFIs), some with concessionary rates and relatively long debt tenors.

African countries strive to attract investments in the generation sector and in many cases IPPs are an important new source of funding. Increased private investment will not materialize simply because large financing gaps are present. Investments will flow only where the return on capital meets the necessary threshold, and where risks are adequately mitigated. Governments, meanwhile, would like investments to serve the public interest by achieving poverty reduction and growth targets. Where public and private interests are well balanced, contracts are less likely to unravel and projects are more likely to have a positive impact across the board.

The primary objective of this study is to evaluate the experience of IPPs in Sub-Saharan Africa and explore how they might be improved. Lessons from past experiences and a review of best practices from the region and from around the world can greatly help countries attract more and better IPPs.

Importance of Investment Flows from Development Partners and Emerging Financiers

Maximizing partnerships with donors and development partners is also paramount to scaling up investments in new generation capacity in Africa.

The financial landscape of energy sector investments has changed considerably in recent years. Capital flows from new financiers (that is, outside the OECD)—such as China, India, and several Arab states—have reached unprecedented levels in the past few years. Chinese-funded investments in generation account for a major part of these external flows. Investments funded by non-OECD financiers are largely part of bilateral assistance, distinct from traditional development assistance and falling instead within a new, broader category of south-to-south cooperation among developing nations (Foster and others 2009). Chinese official economic assistance to the region is typically in the form of loans from the China ExIm Bank, one of the largest export credit agencies worldwide. More recently, the China Development Bank—China's major domestic development bank—has been expanding its portfolio overseas and has funded infrastructure investments in Africa. Infrastructure assets funded through these channels remain publicly owned for the most part, and African governments or their utilities continue to be responsible for their operation and management.

As African countries strive to anchor investments from traditional and nontraditional financiers over the long term, a better understanding of the emerging trends in the financial landscape will help them make informed choices and effectively leverage investments and financial assistance.

Scope of This Study

Following this brief introduction, chapter 2 provides an overview of investment in power generation, with a focus on the current power generation systems of Sub-Saharan Africa, including public and private additions of the past 20 years. Thereafter focus shifts to specific funding sources, including official development assistance (ODA), new financiers, governments, and private investors.

Chapter 3 assesses the enabling environment for IPP investments, including power sector reforms and the critical issues of generation expansion planning, procurement and contracting processes, and the creditworthiness of off-taker utilities, which together may explain why some countries are more successful than others in attracting IPP investments.

In chapter 4, the spotlight turns to IPPs, among the most conspicuous of reform elements, and possibly the engine of the real scale-up of generation systems in Sub-Saharan Africa. Various types of IPPs—which may differ in their ownership and financing structures, technologies, risk mitigation measures, and procurement and contracting mechanisms—are presented. In particular, the study examines and compares competitively bid versus directly negotiated IPPs. The analysis first investigates the power sector characteristics (sector legislation, policies and regulations, generation expansion plans, and supply emergencies) and political economy incentives that drive governments, in certain circumstances, to select direct negotiation rather than use an open bidding process and competitive selection. The analysis assesses and compares the outcomes of the two models, specifically in terms of the cost of power supply.

Chapter 5 concludes with a series of key messages that may be used to help countries take advantage of private capital and competition in procuring new power generation investments.

Methodology

IPPs included in this study are all greenfield, grid-connected installations of 5 megawatts (MW) or greater that have reached financial close, are under construction, or are in operation.[1] A significant amount of data on power projects has been collected and analyzed for this study. Sources include a series of World Bank databases, including the Private Participation in Infrastructure (PPI) database, data from the Energy Information Administration (EIA), and databases prepared by AidData and the OECD, among others. In addition, the authors have conducted primary and secondary source research, particularly for IPPs and Chinese-funded projects. Detailed explanations of the data used, as well as associated limitations, are provided in footnotes in each relevant section.

Apart from the already noted data sources, the analysis and conclusions in chapter 4 are based primarily on original, in-depth case studies carried out in five countries, namely Kenya, Nigeria, South Africa, Tanzania, and Uganda. Country case studies are also included as separate chapters in this book.

The five case study countries were selected because they present the largest and most diversified experience with IPPs over the longest time period. Each country has developed four or more IPPs, a fact that facilitates an assessment of enabling policies and regulatory frameworks, planning and procurement practices, and lessons learned. All five countries have been host to IPPs with different technology bases, which allows for a relatively in-depth evaluation of cost and reliability. Also, their mix of bid structures helps assess the value differences and trade-offs attached to competitive procurement.

The aim of this book is to extract a few key lessons from these core countries that may be generally applied to the scaling up of investment in power generation in Africa and, perhaps, in other developing regions.

Data Limitations

Although an unprecedented body of data and case histories has been collected and analyzed, data limitations remain. Information concerning the composition of investments by funding source; the terms of IPP contracts (which remain mostly confidential); and the size, composition, and types of investment from emerging financiers (notably China) had to be gathered from various sources and triangulated.[2] For Chinese data specifically, the authors used AidData and the World Bank's existing analysis on power investments financed by Chinese sources as a starting point. Additional secondary source research was conducted, and then actual projects were verified with stakeholders in each of the study countries. As nearly every Chinese-funded generation project is directly negotiated with the government of a given African country, there are limited public data available.

The analysis of the Brazilian energy auction and contracting system presented in chapter 4 is intended to provide evidence of policies and practices underpinning competitive power markets, with a look at how they affect cost and technical efficiency. One may argue that Brazil's context is not comparable to Africa, whose power sectors are generally at an incipient stage of development. This is true. But the Brazilian analysis only seeks to highlight some basic principles that should inspire policy decisions: notably, robust planning, competition in the procurement of new generation, coherent sector oversight, and an unremitting emphasis on improving the performance of the utilities that are the ultimate off-takers. Such principles are valid at any latitude.

The focus of this report is on power generation, as opposed to the transmission and distribution (T&D) of electricity. While inadequate T&D is clearly a constraint on any effort to widen service access, countries must have sufficient generation capacity to be able to serve new customers, improve welfare, and accelerate economic development. Also, a detailed discussion of the environmental externalities attached to specific IPP technologies—which pose growing concern—lies outside the purview of this report.

Finally, South Africa's size and prominence in the generation of Sub-Saharan Africa's electric power is noteworthy. The authors have opted to include South Africa even though it dramatically shifts some of the numbers. Efforts have been made to present Sub-Saharan African tallies with and without South Africa.

Notes

1. While the primary criterion for including IPPs in our data is financial close, in select cases, projects may be mentioned that are on the verge of financial close, for example, the renewable energy feed-in tariffs in Uganda, for which financial close was anticipated in 2015. As of 2015, not all awarded projects had reached financial close or had started construction and some had been canceled through failure to fulfill conditions precedent. Also mentioned is Window 4 of South Africa's Renewable Energy Independent Power Project Procurement Programme. These projects do not, however, form the core of the project analysis.
2. As noted in chapter 2, amid a lack of available data, government and utility megawatts and investments have largely been derived by (1) subtracting the megawatt totals of IPPs, Chinese-funded investment, official development assistance, and investment from multilateral finance institutions and development finance institutions, and then (2) using the Energy Information Administration's corresponding data on "megawatts installed by technology" to determine residual megawatts per technology, and finally (3) ascribing a value, based on average costs per technology in Sub-Saharan Africa. Wherever possible, efforts have been made to verify the megawatts and the technology with known projects undertaken by the government.

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CHAPTER 2

Investment in Power Generation in Sub-Saharan Africa: An Overview

Current Power Generation Systems in Sub-Saharan Africa

In 2013, the 48 countries of Sub-Saharan Africa had a total grid-connected power generation capacity of 83 gigawatts (GW). South Africa accounts for just over half of this total, using mostly coal, and thus radically changes the power landscape. (Unless explicitly stated, subsequent references to Sub-Saharan Africa exclude South Africa.) The remaining countries combined have only 36 GW, produced from a wider array of resources (as described below). Just 13 countries have power systems larger than 1 GW, and they account for more than 80 percent of the power capacity in Sub-Saharan Africa (see table 2.1).

Twenty-seven Sub-Saharan African countries have grid-connected power systems smaller than 500 megawatts (MW), and 14 smaller than 100 MW.

Across Sub-Saharan Africa, hydropower contributes the most capacity (51 percent), followed by fossil fuels (24 percent natural gas, 18 percent diesel/heavy fuel oil [HFO]), coal (5 percent), and other renewables (1 percent) such as biomass, geothermal, wind, and solar (figure 2.1).

Installed capacity in Sub-Saharan Africa is 44 MW per million people, compared with 192 MW in India, 590 MW in Latin America, and 815 MW in China (U.S. EIA 2014; IEA 2011).

Power Generation Capacity Additions over the Past 20 Years

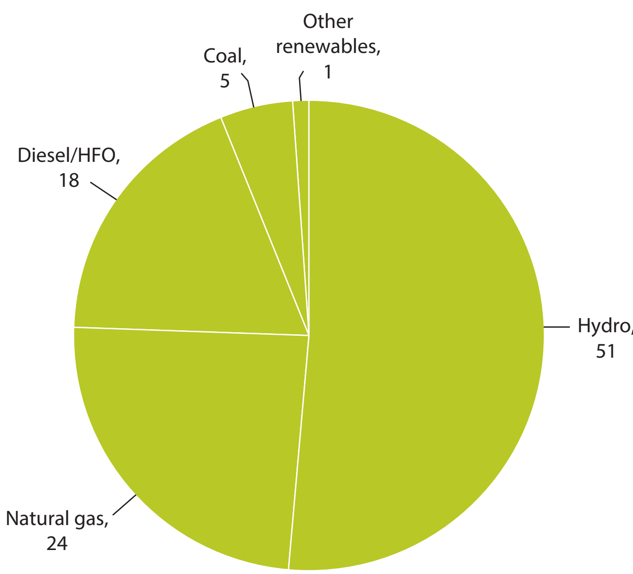
Power investments between 1990 and 2013 were far below requirements; only 15.63 GW net was added across Sub-Saharan Africa.[1] Investments were particularly paltry from 1990 to 2000, when only 1.84 GW of new capacity was installed. In this period, a number of countries actually saw their systems contract, which may be attributed in part to civil wars and lack of system maintenance—most notably in the Democratic Republic of Congo and Côte d'Ivoire, but also in countries such as Angola, the Central African Republic,

Table 2.1 Significant Installed Power Generation Capacity and Gross Domestic Product: Sub-Saharan Africa, 2013

Country	*Capacity (MW)*	*GDP (PPP) 2013 (current int'l $, billions)*
Nigeria	7,044	972.65
Sudan	3,038	153.09
Ghana	2,812	103.65
Congo, Dem. Rep.	2,444	50.47
Mozambique	2,382	28.40
Ethiopia	2,094	129.86
Zambia	1,985	57.07
Zimbabwe	1,970	25.92
Kenya	1,766	124.02
Tanzania	1,659	117.66
Côte d'Ivoire	1,521	65.55
Angola	1,509	166.11
Cameroon	1,238	69.98

Sources: Data on capacity are compiled by the authors from various sources; data on GDP are from the World Bank's World Development Indicators.
Note: GDP = gross domestic product; MW = megawatt; PPP = purchasing power parity.

Figure 2.1 Power Generation Sources: Sub-Saharan Africa, 2013
percent

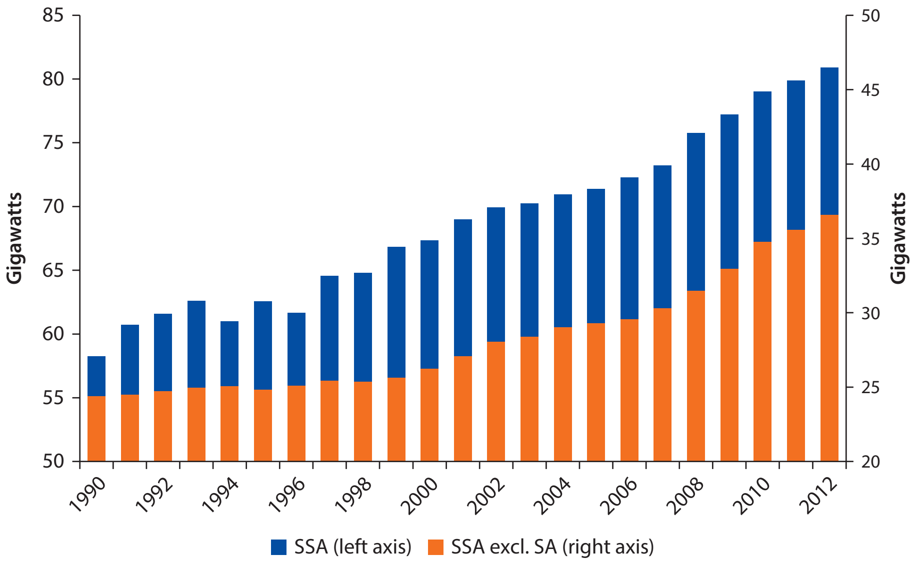


Source: Authors' compilation of data from U.S. EIA 2014.
Note: HFO = heavy fuel oil.

Ghana, Liberia, Nigeria, Sierra Leone, Somalia, and Zimbabwe. Since 2000, investments have picked up and an additional 13.8 GW has been installed in the region, excluding South Africa (figure 2.2).

Fourteen countries (table 2.2) account for around 94 percent of capacity additions between 2000 and 2013.

Figure 2.2 Grid-Connected Generation Capacity: Sub-Saharan Africa, 1990–2013



Source: Authors' compilation of data from U.S. EIA 2014.
Note: SA = South Africa; SSA = Sub-Saharan Africa.

Table 2.2 Significant Power Generation Capacity Additions: Sub-Saharan Africa, 2000–13

Country	*Megawatts added*
Sudan and South Sudan	2,218
Ghana	1,648
Ethiopia	1,576
Nigeria	1,156
Angola	923
Tanzania	797
Botswana	761
Kenya	718
Uganda	599
Côte d'Ivoire	537
Congo, Rep. (Brazzaville)	507
Cameroon	442
Senegal	377

Sources: U.S. EIA 2014, utility annual reports, and consultations with World Bank country staff.

The remaining 6 percent of capacity—that is, around 879 MW—was distributed across 34 countries. A number of countries added hardly any capacity in this period (and some actually lost capacity), including Burundi, the Central African Republic, the Democratic Republic of Congo, Lesotho, Liberia, Mozambique, and Niger, where again civil strife and a lack of adequate system maintenance were prevalent.

Independent Power Projects

Independent power projects (IPPs) in Sub-Saharan Africa date to 1994, when investors first made inroads into Côte d'Ivoire, followed by Kenya (1996), and Mauritius (1997). Senegal, Tanzania, and Ghana were also among the early destinations for private capital in 1997–99. With few exceptions, these initial deals, for (domestic) gas and (imported) diesel-fueled projects, were directly negotiated with state-owned utilities. In nearly all instances, investment climates were poor, particularly when compared with those of other developing regions, with insolvent utilities the norm. Deals were sealed with various investment risk mitigation mechanisms. In some instances, generous power purchase agreements (PPAs) were coupled with government guarantees and escrow accounts. In the two decades since IPPs first emerged, considerable changes have taken place, but there are remnants of the conditions and procurement approaches that first shaped private power projects.

Since their inception, IPPs have spread across Sub-Saharan Africa and are now present in 17 countries (excluding South Africa)—all with varying degrees of sector reform and private participation. Currently, there are 59 projects (greater than 5 MW) in Sub-Saharan Africa (excluding South Africa), totaling \$11.12 million in investments and 6.8 GW of installed generation capacity.[2] South Africa adds 67 IPPs, bringing the total to 126 IPPs, with an overall installed capacity of 11.01 GW and investments of \$25.6 billion.[3]

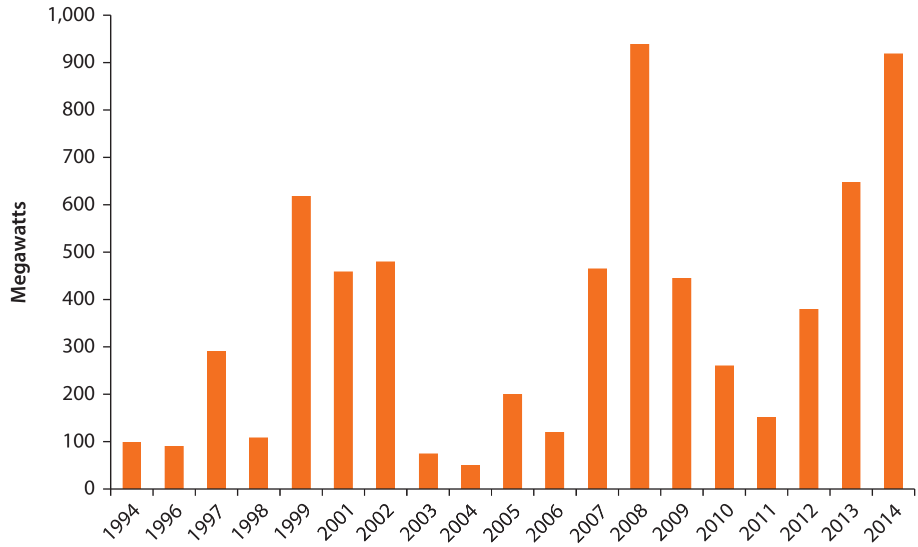
Figures 2.3 through 2.7 provide perspectives on the location and capacity of IPPs in Sub-Saharan Africa (excluding South Africa).

IPPs are conspicuous across these diverse contexts, with notable concentrations in South Africa, Nigeria, Kenya, Côte d'Ivoire, Ghana, Uganda, and Tanzania. Five of these countries form the basis for this book's case studies.

IPPs represent a minority of total generation capacity and have mainly complemented incumbent state-owned utilities. Nevertheless, IPPs represent an important source of new investment in the power sector in a number of African countries. For instance, in Togo, Centrale Thermique de Lomé (CTL), the country's first IPP, raised installed capacity by approximately 67 percent (from 149 MW to 249 MW); meanwhile, Bujagali increased Uganda's installed capacity by about 30 percent (250 MW) when it came online in 2012.

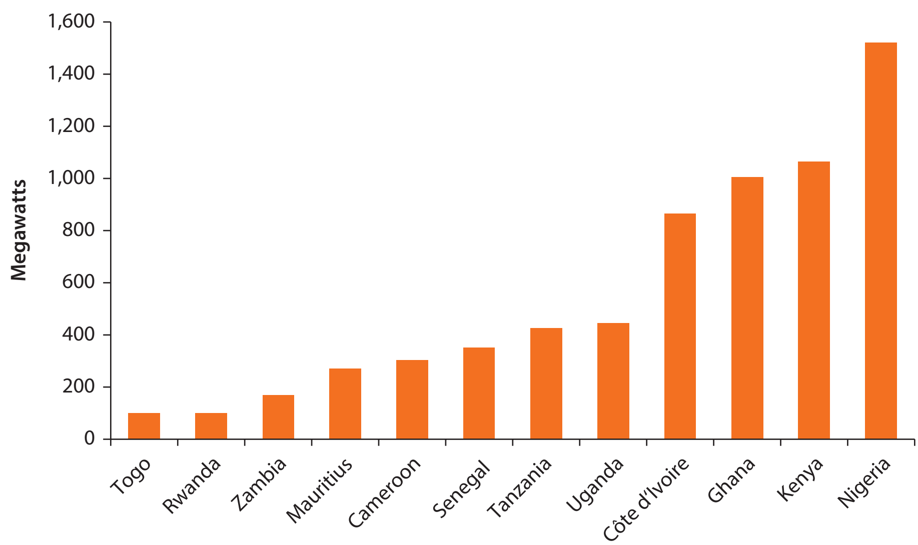
Of the present pool of 59 IPPs that have reached financial close, Kenya and Uganda have the highest number.[4] If Uganda closes another 10 projects as expected, it will contribute a total of 21 projects to this sum. It is noteworthy that three-quarters of the projects in these two countries have closed within the past three years. Thus, more than 50 percent of the total IPP pool, in terms of

Figure 2.3 Independent Power Projects, by Year of Financial Close: Sub-Saharan Africa (Excluding South Africa), 1994–2014



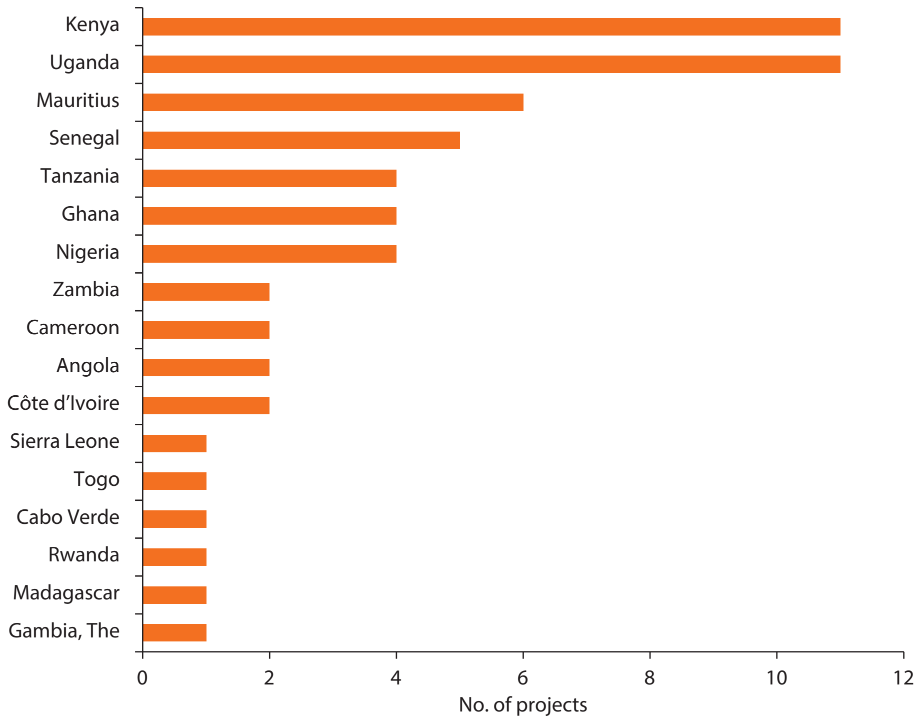
Source: Compiled by the authors, based on utility data, primary sources, and the Private Participation in Infrastructure (PPI) database.
Note: No projects reached financial close in 1995 or 2000.

Figure 2.4 Countries with the Most Independent Power Project Capacity: Sub-Saharan Africa (Excluding South Africa), 1994–2014



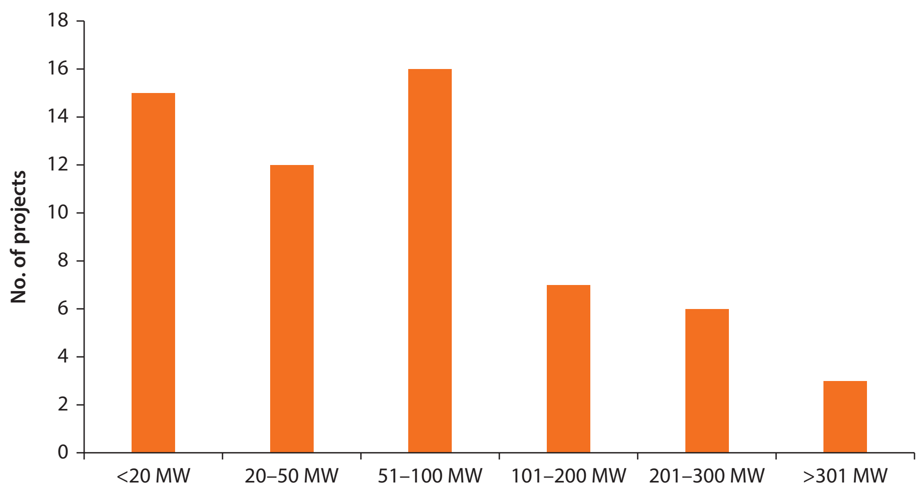
Source: Compiled by the authors, based on utility data, primary sources, and the Private Participation in Infrastructure (PPI) database.
Note: Not included in this graph are smaller capacity additions in the following countries: Madagascar (15 MW), Sierra Leone (15 MW), The Gambia (25 MW), Cabo Verde (26 MW), and Angola (46 MW), which contribute a sizable amount to the overall installed capacity of these countries.

Figure 2.5 Number of Independent Power Projects: Sub-Saharan Africa (Excluding South Africa), 1994–2014



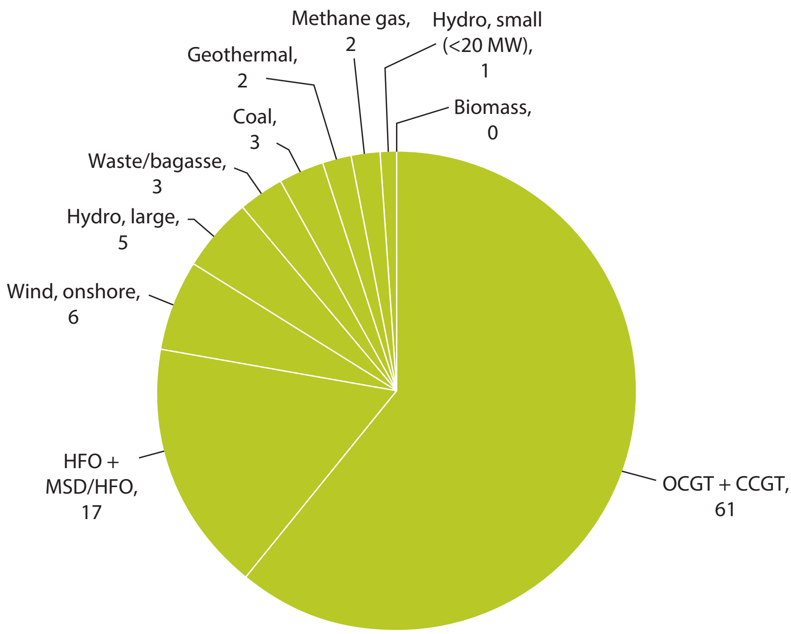
Source: Compiled by the authors, based on utility data, primary sources, and the Private Participation in Infrastructure (PPI) database.

Figure 2.6 Number of Independent Power Projects in Various Size Categories to Have Reached Financial Close: Sub-Saharan Africa (Excluding South Africa), as of 2014



Source: Compiled by the authors, based on utility data, primary sources, and the Private Participation in Infrastructure (PPI) database.
Note: MW = megawatts.

Figure 2.7 Independent Power Project Capacity (% of MW), by Technology: Sub-Saharan Africa (Excluding South Africa), 1994–2014
percent



Source: Compiled by the authors, based on utility data, primary sources, and the Private Participation in Infrastructure (PPI) database.
Note: Not featured here are solar and biomass, each representing less than 1 percent of the total. CCGT = combined-cycle gas turbine; HFO = heavy fuel oil; MSD = medium-speed diesel; MW = megawatts; OCGT = open-cycle gas turbine.

number of projects, is concentrated in two countries and is relatively new. The balance developed slowly over the two decades since the first large-scale IPP reached financial close in 1994 in Côte d'Ivoire.

IPPs in Sub-Saharan Africa range in size from a few megawatts to around 600 MW. There are a handful of projects larger than 300 MW (mostly in Nigeria), and a dozen projects sized 100–300 MW. Two-thirds of the IPPs are smaller than 100 MW; these are more or less evenly distributed across three size categories, of less than 20 MW, 21–50 MW, and 51–100 MW.

The majority of IPP capacity is thermal. Open- and combined-cycle gas turbines (OCGT, CCGT) are the most dominant, though there is considerable diversity within technologies (figure 2.7) and important growth to be noted in renewables. For example, three different wind projects in Kenya and Cabo Verde reached financial close between 2010 and 2014. Similarly, there have been several new small hydropower projects (< 20 MW), most prominent in Uganda, though also seen in Madagascar and Angola over the past decade. South Africa procured 3.9 GW in private power between 2012 and 2014, all of which is renewable.[5] As shown in table 2.3, wind represents the greatest portion of this new capacity, followed by solar (photovoltaic [PV] and concentrated solar power [CSP]).[6]

Table 2.3 Renewable Energy Investments: South Africa, 2012–14

	Wind	*PV*	*CSP*	*Hydro*	*Biomass*	*Biogas*	*Landfill*	*Total*
Capacity (MW)	1,984	1,484	400	14	16	0	18	3,915
Projects awarded	32	23	5	2	1	0	1	64
Investment (US$, millions)	4,683	5,085	3,806	79	108	0	29	13,790

Source: Eberhard, Kolker, and Leigland 2014.
Note: CSP = concentrated solar power; MW = megawatt; PV = photovoltaic.

Chinese-Supported Power Generation Projects

Another area of significant capacity additions in Sub-Saharan Africa may be linked to Chinese-funded generation assets. Of these, 6.3 GW[7] reached financial close between 1990 and 2013; another 1.2 GW was expected to either reach financial close or be under construction in 2014, for a total of 34 projects.[8] Figures 2.8–2.10 compare Chinese-funded power projects against IPPs, including and excluding South Africa.

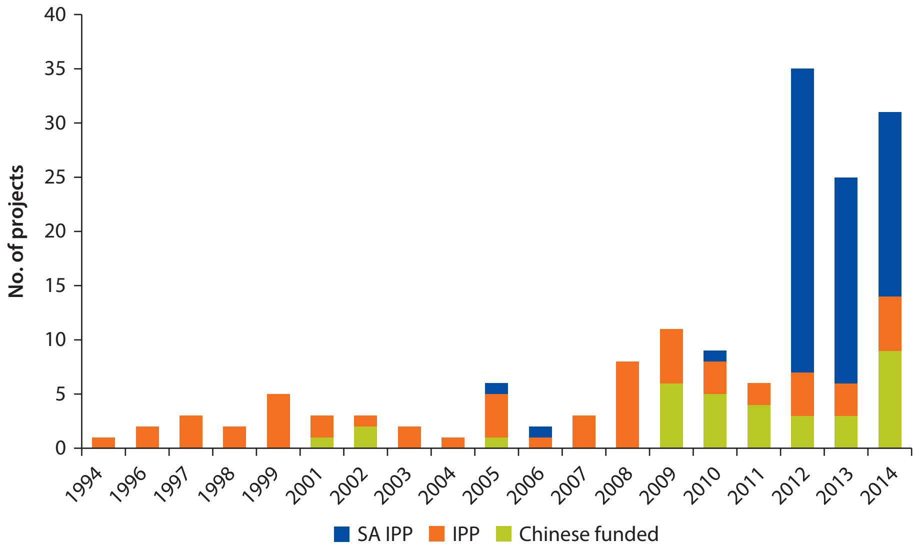
While there is currently more operational IPP capacity than completed Chinese-funded capacity, the picture is changing. In terms of total megawatts to have reached financial close, for the five years from 2010 to 2014, Chinese-backed investments exceeded those in IPPs. Chinese-funded projects have an average size of 226 MW, in contrast to IPPs' average of 114 MW. Three-quarters of Chinese-funded projects are larger than 100 MW, and a third equal to or larger than 300 MW.

Chinese-funded projects do not follow an expected pattern. There appears to be no correlation between Chinese-backed investment in generation and the resource wealth of the countries where investments are made. Chinese-funded generation projects exist in the following 19 countries: Botswana, Cameroon, the Central African Republic, the Democratic Republic of Congo, the Republic of Congo, Côte d'Ivoire, Equatorial Guinea, Ethiopia, Gabon, Ghana, Guinea, Liberia, Mali, Nigeria, Sudan, Togo, Uganda, Zambia, and Zimbabwe. Some of these are resource-rich countries, and some are not. Eight have IPPs, again signaling no apparent pattern. Excluding macroeconomic considerations that may help determine investment, the one notable characteristic is the preponderance of a particular technology: the large hydropower projects[9] (that compose 4.9 GW, or approximately 63 percent, of total Chinese-funded capacity), for which Chinese engineering, procurement, and construction (EPC) contractors have become renowned worldwide.

Who Has Funded What?

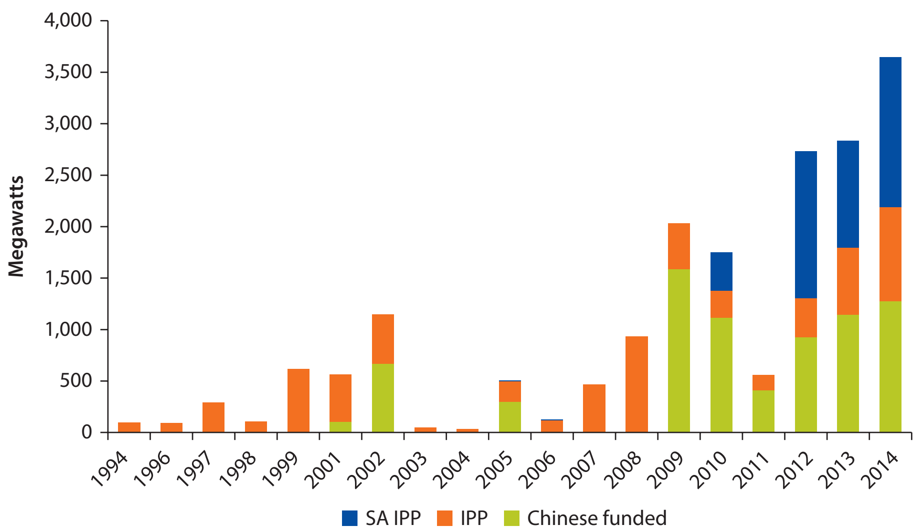
How were these power investments financed? What proportion was funded by host governments or their utilities through debt, what by official development assistance (ODA)[10] and concessionary loans from development finance institutions (DFIs), and what by private IPPs? And what are the

Figure 2.8 Comparison of Chinese-Funded Power Projects and IPPs, by Total Number: Sub-Saharan Africa (with and without South Africa), 1994–2014



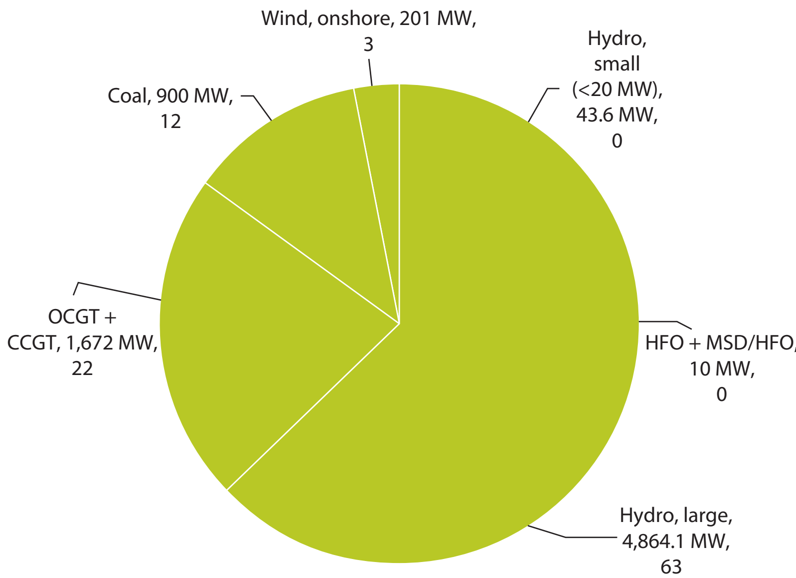
Source: Compiled by the authors, based on various primary and secondary sources.
Note: No IPPs recorded for 1995 or 2000, which explains the absence of those years in the figure. IPP = independent power project; SA = South Africa.

Figure 2.9 Comparison of Chinese-Funded Power Projects and IPPs, by Generation Capacity: Sub-Saharan Africa, 1994–2014



Source: Compiled by the authors, based on various primary and secondary sources.
Note: No IPPs recorded for 1995 or 2000, which explains the absence of those years in the figure. The total for 2014 includes projects that were under construction and had not yet reached financial close. IPP = independent power project; SA = South Africa.

Figure 2.10 Chinese-Supported Power Project Capacity (% of MW), by Technology: Sub-Saharan Africa, 2001–14
percent



Source: Compiled by the authors, based on various primary and secondary sources.
Note: CCGT = combined-cycle gas turbine; HFO = heavy fuel oil; MSD = medium-speed diesel; MW = megawatt; OCGT = open-cycle gas turbine.

trends in new financing sources, such as China? These are the questions that will be answered in this section.

The Financing Landscape since 1990

Between 1990 and 2013, approximately $45.6 billion (nominal) was invested in electric power generation in Sub-Saharan Africa. Excluding South Africa, this figure falls to $31.3 billion, far below what is required to meet Africa's growth and development aspirations. Table 2.4 depicts the major types of investment and the associated megawatts added over the period.

Over the past 25 years, governments and utilities have been the largest funders of the sector. Some such investment has come from national treasuries, some through utility-retained earnings, and the remaining from bond issues or loans from commercial banks. In recent years, however, the financing picture has changed, with larger amounts coming from IPPs[11] and China. Figure 2.11 illustrates the shift, in the years 1994–2013, toward IPPs (private debt and equity plus private sector DFI finance) and Chinese funding, while funding from ODA (here distinguished as OECD [Organisation for Economic Co-operation and Development] and bilateral funding), concessional DFIs (multilateral), and Arab donors (also predominantly concessional) has remained relatively flat. Among new financiers, China is dominant, India has made modest investments, and Brazilian and Russian involvement is still relatively miniscule. As all investment is

Table 2.4 Total Investment in Completed Power Generation Plants: Sub-Saharan Africa (Excluding South Africa), 1990–2013

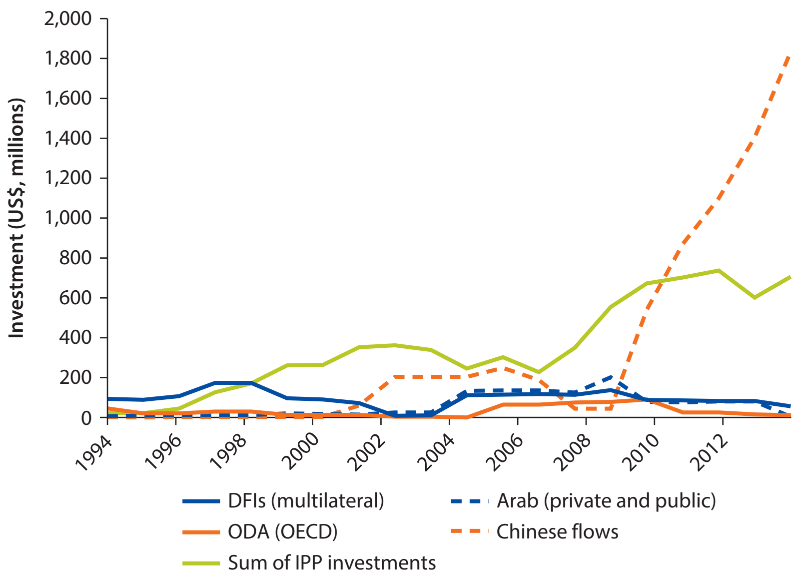
Type of investment	*Debt and equity (US$, millions)*	*MW added*	*% of total MW*	*% of total investment*
Government and utilities	15,883.87	8,663.26	43.66	50.67
IPPs	6,950.12	4,760.60	23.99	22.17
China	5,009.80	3,263.73	16.45	15.98
ODA, DFI, and Arab funds	3,506.48	3,156.15	15.91	11.18
Total	**31,350.27**	**19,843.73**	**100.00**	**100.00**

Source: Compiled by the authors, based on various primary and secondary sources.
Note: Total megawatts installed are based on data from the U.S. EIA and the World Bank. IPP and China megawatt and investment totals are based on extensive primary and secondary source data (including the PPI database, AidData, and direct correspondence with country and project contacts). ODA (including concessionary DFI/MFI and Arab funding) has been sourced by AidData (for which the OECD data are a reference point) and cross-checked with secondary sources. The authors have also actively engaged with researchers at both AidData, the OECD, and those involved in the AICD. Data for India-funded capacity and investment in Sub-Saharan Africa have been obtained directly from the ExIm Bank of India. Finally, government and utility capacity and investments have largely been derived—amid a lack of available data—by (1) subtracting the aforementioned MW totals (of IPP, China investment, and ODA/MFI/DFI) and then (2) using EIA's corresponding "MW installed by technology" data to determine residual megawatts per technology, and finally (3) ascribing a value, based on average costs per technology in Sub-Saharan Africa. Wherever possible, efforts have been made to verify the megawatts and the technology with the known projects undertaken by the government.

The data exclude projects that have reached financial close but do not have a COD. Hence numbers will differ from those quoted elsewhere in the text for IPPs and Chinese-funded projects, especially in recent years, which have seen a significant increase in the number of projects that have reached financial close. The total megawatts added exceed the figure of net megawatts previously quoted in the text, as about 3,800 MW of capacity has been retired over the period.

AICD = Africa Infrastructure Country Diagnostic; COD = commercial operation date; DFI = development finance institution; EIA = U.S. Energy Information Administration; IPP = independent power project; MFI = multilateral finance institution; MW = megawatt; ODA = official development assistance; OECD = Organisation for Economic Co-operation and Development; PPI = Private Participation in Infrastructure.

Figure 2.11 Investments in Power Generation, Five-Year Moving Average: Sub-Saharan Africa (Excluding South Africa), 1994–2013



Source: Compiled by the authors, based on various primary and secondary sources.
Note: Ghana's Kpone IPP and Nigeria's Azura investments in 2014 and 2015, respectively, which together total $900 million, will result in a continued upward tick in IPP investments. DFI = development finance institution; IPP = independent power project; ODA = official development assistance; OECD = Organisation for Economic Co-operation and Development.

spread, in practice, across project construction periods, figure 2.11, with five-year rolling averages, provides a more realistic picture of funding disbursements.[12]

The balance of this chapter will focus on the growth and composition of IPPs and Chinese-funded investments.

Financing Independent Power Projects

The first IPP investment took place in 1994 in Côte d'Ivoire. Shortly thereafter, Ghana, Kenya, Nigeria, Senegal, Tanzania, and Uganda, among others, opened their doors to private sector participation in generation. Investors were not attracted by the general investment climate, as would otherwise be the case, or the adoption of key power sector reforms. Instead, the countries where IPPs and other private participation took root were those where competitive procurements were initiated or directly negotiated deals were possible, and where security and credit enhancement mechanisms created the opportunity to achieve required rates of return.

There have been three major IPP investment spikes, in the period 1999–2001, the year 2007, and then again from 2011 until 2014. Foreign investment flows into Africa's power sector slowed after the collapse of Enron (and the withdrawal of other U.S. firms) and again in 2008 after the global financial crisis. Each investment spike is associated with the financial close of a small number of comparatively large projects. For instance, 1999 saw the financial close of the first 288 MW on the Azito OCGT project in Côte d'Ivoire, as well as the first phase (220 MW) of the Takoradi II OCGT in Ghana. Financial close was also reached on OrPower4 (geothermal) and Tsavo (diesel) in Kenya during this year. The 2007 spike is associated with even fewer projects and may be attributed mainly to the close of Uganda's 250 MW Bujagali project, which still represents Sub-Saharan Africa's largest private hydropower installation, at $860 million.[13]

From 2011, investments began taking off. The years since (2011–14) constitute the largest and most sustained investment cycle to date, representing 14 projects (excluding South Africa), $4.9 billion in investment, and an additional 2.1 GW in capacity. Within this upsurge are several expansions and thus the continuation of specific projects: for example, the 36 MW expansion of OrPower4, the 110 MW expansion of Takoradi II, the 111 MW expansion of Côte d'Ivoire's Compagnie Ivoirienne de Production d'Électricité (CIPREL)—Sub-Saharan Africa's first IPP—as well as the 146 MW expansion of Azito. These are joined by a swath of new projects that include three diesel-fired plants in Kenya, which introduced unprecedented competition in Kenya and secured partial risk guarantees (PRGs) from the World Bank; the 125 MW Sendou coal project in Senegal, which tapped domestic coal reserves; and the 350 MW Kpone gas-to-power plant in Ghana. The upward trend in IPP investments in Sub-Saharan Africa since 2011 is even more pronounced if South Africa is included. In 2015, this figure rose still further with the financial close of the 459 MW Azura Nigerian IPP, which harnesses domestic natural gas.

With the exception of South Africa and Mauritius, none of the Sub-Saharan African countries with IPPs has an investment-grade rating. Table 2.5 provides a comprehensive list of all sovereign credit ratings in Sub-Saharan Africa.

Table 2.5 Long-Term Sovereign Credit Ratings: Sub-Saharan Africa, January 2014

Country	*Moody's*	*Fitch*	*S&P*	*IPPs present*	
Botswana	A2		A–	No	Investment grade in SSA, only four countries, two of which (bolded) have IPPs: South Africa and Mauritius
South Africa	Baa1	BBB	BBB	Yes	
Mauritius	Baa1			Yes	
Namibia	Baa3	BBB–		No	
Angola	Ba3	BB–	BB–	Yes	Sixteen countries have received a speculative grade rating, 10 of which (bolded) have IPPs; the majority occurred after countries received sovereign ratings
Gabon		BB–	BB–	No	
Nigeria	Ba3	BB–	BB–	Yes	
Lesotho		BB–		No	
Senegal	B1		B+	Yes	
Kenya	B1	B+	B+	Yes	
Cabo Verde		B+	B+	Yes	
Zambia	B1	B+	B+	Yes	
Ghana	B1	B+	B	Yes	
Mozambique		B	B+	No	
Uganda		B	B+	Yes	
Cameroon		B	B	Yes	
Rwanda		B	B	Yes	
Seychelles		B		No	
Burkina Faso			B	No	
Benin			B	No	

Source: Adapted from Mecagni and others 2014: 20–21.
Note: IPP = independent power project; S&P = Standard & Poor's; SSA = Sub-Saharan Africa.

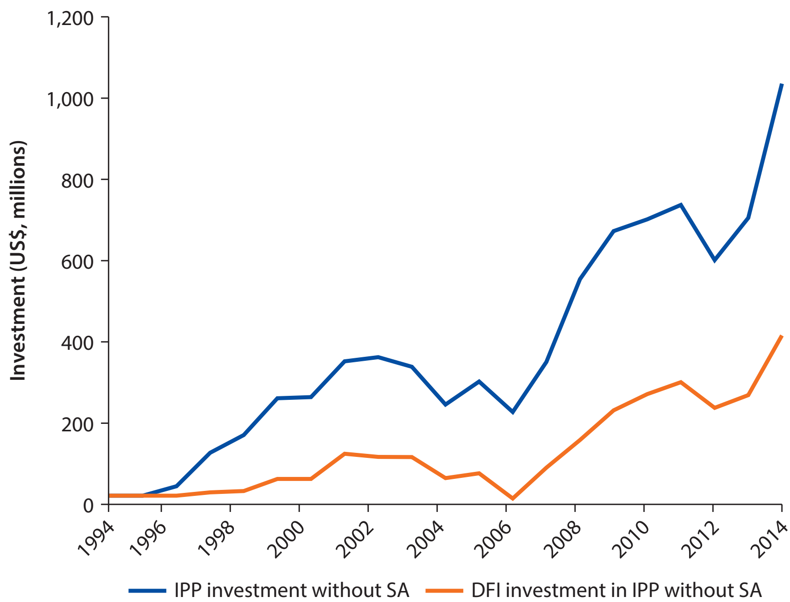
Of the 10 countries with IPPs that have received a speculative rating (Angola, Cabo Verde, Cameroon, Ghana, Kenya, Nigeria, Rwanda, Senegal, Uganda, Zambia), six of these ratings (Angola, Kenya, Nigeria, Rwanda, Senegal, and Uganda) were received after the first IPP deals were signed.[14] For instance, Kenya's investment climate was defined, at the time, by its aid embargo in the mid-1990s. Tanzania is also worth mentioning in this context. Throughout the 1990s, all export credit agencies were off cover in Tanzania and no foreign commercial banks were willing to lend. The possibility of a traditional project-financed IPP deal in this climate was limited. Nevertheless, as has already been noted, IPP projects were developed in challenging investment climates.

With less than favorable investment conditions, DFIs that invest in the private sector—such as the International Finance Corporation (IFC), the Netherlands Development Finance Company (FMO), the German Investment and Development Corporation (DEG), Proparco, and the Norwegian Investment Fund for Developing Countries (Norfund)—have made a significant contribution to funding IPPs, as shown in figure 2.12.

A breakdown of IPP investment by country is provided in figure 2.13. The greatest investments have gone to Nigeria, Kenya, and Uganda for more than a decade, and in the case of Kenya for nearly two decades.

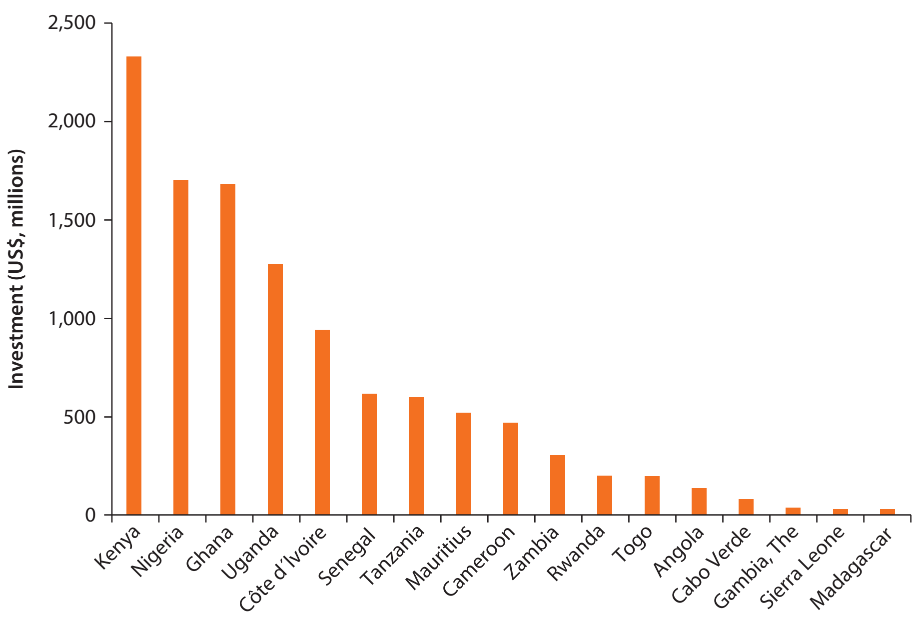
Later chapters in this book will analyze why there has been an uptick in private investment in power in recent years and why certain countries have been

Figure 2.12 Total Investment by IPPs and by Development Finance Institutions: Sub-Saharan Africa (Excluding South Africa), 1994–2014



Source: Compiled by the authors, based on various primary and secondary sources.
Note: DFI = development finance institution; IPP = independent power project; SA = South Africa.

Figure 2.13 Investment in Independent Power Projects, by Country: Sub-Saharan Africa, 1994–2014



Source: Compiled by the authors, based on various primary and secondary source data.

Table 2.6 Largest Independent Power Projects, by Investment Total and Capacity: Sub-Saharan Africa (Excluding South Africa), 1994–2014

Project	*Country*	*Investment (US$, millions)*	*Capacity (MW)*
Kpone IPP	Ghana	900	350
Lake Turkana Wind Power	Kenya	861	300
Bujagali Hydro Project	Uganda	860	250
Afam	Nigeria	540	630
Okpai	Nigeria	462	480
Aba Integrated	Nigeria	460	141
Takoradi II	Ghana	440	330
Azito	Côte d'Ivoire	430	434

Source: Compiled by the authors, based on various primary and secondary source data.
Note: IPP = independent power project; MW = megawatt.

more successful than others in attracting IPP investments. Total IPP investment in 1990–2013 (as recorded in table 2.4) stood at $6.95 billion, based on megawatts installed; this number swells to $8.7 billion if all projects that reached financial close between 1990 and 2013 are included. In 2014 alone, another $2.3 billion was added, for a total of $11.12 billion, representing a significant upsurge and reflecting several of the financial closes.[15]

Previously, IPP investments in South Africa lagged those in other Sub-Saharan countries, but between 2012 and 2014 the country closed $14 billion in renewable energy IPPs—more than double the total in the rest of Sub-Saharan Africa over the past two decades. South Africa also boasts the largest such single investment: the Kaxu Solar One, with 100 MW CSP, at approximately $976 million. The largest projects in terms of total investment in Sub-Saharan Africa, excluding South Africa, are listed in table 2.6. A complete list of IPP projects in Sub-Saharan Africa is included in appendix E.

The Relatively New and Growing Trend of Chinese Funding

In addition to IPPs, the generation sector has seen substantial investments from China since 2001, with their growth accelerating in recent years. As of 2014, based on financial close, Chinese-funded projects exceeded IPPs in total dollars invested (approximately $13.4 billion, compared to $11.5 billion). The majority of these projects received funding from the China ExIm Bank, responsible for soft loans and export credit, on the part of the Chinese government. Additional finance has been provided by the Industrial and Commerce Bank of China and China Development Bank, with the latter providing primarily commercial loans. In addition to these three, both the China Construction Bank and Bank of China are involved in energy sector investments. The ExIm and the China Development Bank remain state owned. Of the other entities named, the government owns two-thirds, and one-third is publicly traded. The China-Africa Development Fund is an additional, more recent, source of concessionary finance.

The typical project structure involves an EPC plus a financing contract, which means EPCs will have a preliminary support letter or letter of interest

Table 2.7 Largest Chinese-Funded Projects in Sub-Saharan Africa, by Investment and Capacity, 2001–14

Project	*Country*	*Investment (US$, millions)*	*Capacity (MW)*
Karuma Hydropower Project	Uganda	1,688	600
Zungeru Hydropower Project	Nigeria	1,293	700
Morupule B Power Station	Botswana	970	600
Omotosho Power Plant II (NIPP)	Nigeria	660	513
Memve'ele Hydropower Project	Cameroon	637	201
Bui Hydropower Project	Ghana	621	400
Soubré Hydropower Project	Côte d'Ivoire	571	270

Source: Compiled by the authors, based on various primary and secondary source data.
Note: MW = megawatt; NIPP = national integrated power project.

from the "cooperation banks." There is competition among Chinese EPCs, and the selected EPC will start work—generally with its own funds—prior to the disbursement of the bank loan, provided that the bank passes its evaluation of the project loan. The majority of loans (80 percent) are entered into between Sub-Saharan African governments and the said cooperation banks. The balance, 20 percent, is given directly to Chinese special-purpose vehicles (SPVs) or EPCs for projects.

Table 2.7 showcases the largest Chinese-funded projects, based on investment costs. A comprehensive list of Chinese-supported power projects in Sub-Saharan Africa appears in appendix D.

Official Development Assistance and Concessional Funding Trends

There has been considerable fluctuation in ODA and concessional funding figures in the past two decades; however, this has been overshadowed by IPP and Chinese-supported investment, as previously noted. Figure 2.14 shows these developments, once again disaggregating ODA (OECD/bilateral), concessional DFI (multilateral), and largely concessional Arab funding. A decline in ODA in the early 2000s and after 2008 exacerbated the dip in private investment in these years.

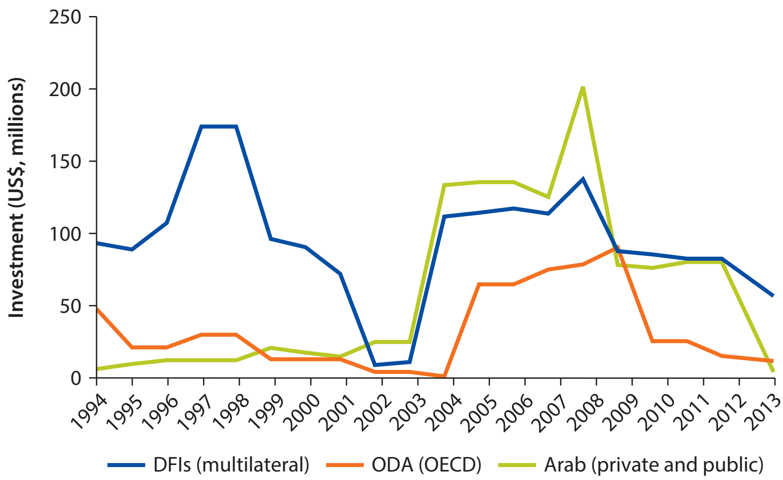
Concessional DFIs (multilateral, and excluding the funding of IPPs) contributed approximately $1.9 billion, excluding South Africa, followed by Arab funds at $1.2 billion and ODA (OECD/bilateral) at $747 million. Recent loans to Eskom in South Africa from the World Bank (International Bank for Reconstruction and Development, IBRD) and African Development Bank (AfDB), at $1.54 billion and $1.14 billion, respectively, exceed total concessionary DFI flows to the rest of Sub-Saharan Africa over the past two decades.

ODA and concessional funding is found in approximately 30 projects. The largest single project funded by Arab flows, the Merowe Dam (Sudan), explains the spike from 2004. The Gilgel Gibe I and II hydroelectric plants

(Ethiopia) received a combination of multilateral, bilateral, and government aid (tables 2.8 and 2.9).

In summary, while public utilities have historically been the major sources of funding for new power generation capacity, that trend is changing. Most African governments are unable to fund their power needs, and most utilities do not have investment-grade ratings and are unable to raise sufficient debt at affordable rates. ODA and DFIs have only partially filled the funding gap. The fastest-growing sources of finance are from China and the private sector.

Figure 2.14 Official Development Assistance, Development Finance Institutions (Excluding IPP Investments), and Arab Investment in Power Generation, Five-Year Moving Average: Sub-Saharan Africa (Excluding South Africa), 1994–2013



Source: Compiled by the authors, based on various primary and secondary source data.
Note: DFI = development finance institution; IPP = independent power project; ODA = official development assistance; OECD = Organisation for Economic Co-operation and Development.

Table 2.8 Largest Power Projects Funded by Official Development Assistance, Arab Sources, or Development Finance Institutions, by Capacity and Funding Source: Sub-Saharan Africa, 1994–2013

Project	*Country*	*Capacity (MW)*	*Funding sources*
Medupi Power Station	South Africa	4,800	WB, AfDB
Merowe Dam	Sudan	1,250	Arab funds, AFESD
Expansion of Roseires Dam	Sudan	700–900	Arab funds, AFESD
Morupule B Power Station	Botswana	600	AfDB, WB
Gilgel Gibe II	Ethiopia	420	Italy, EIB, WB

Source: Compiled by the authors, based on various primary and secondary source data.
Note: AfDB = African Development Bank; AFESD = Arab Fund for Economic and Social Development; EIB = European Investment Bank; MW = megawatt; WB = World Bank.

Table 2.9 Largest Power Projects Funded by Official Development Assistance, Arab Sources, or Development Finance Institutions, by Investment and Capacity: Sub-Saharan Africa, 1994–2013

Project	*Country*	*DFI/ODA/Arab investment (US$, millions)*	*Capacity (MW)*
Medupi Power Station (coal)	South Africa	2,677	4,800
Merowe Dam	Sudan	1,413	1,250
Gilgel Gibe II	Ethiopia	590	420
Expansion of Roseires Dam	Sudan	441	700–900
Takoradi Thermal Power Plant	Ghana	301	300

Source: Compiled by the authors, based on various primary and secondary source data.
Note: DFI = development finance institution; MW = megawatts; ODA = official development assistance.

Notes

1. That is, after taking into account capacity that was removed from the system. This total (24.85 GW) is based primarily on data from the U.S. Energy Information Administration (EIA), with minor adaptations, and supplemented with 2013 World Bank data. While the EIA data are not perfect and the authors have noted a number of anomalies, they nevertheless provide a reasonable view of overall trends, and, including annual installed global data, compose one of the most comprehensive databases available. Furthermore, although the EIA provides a picture of overall capacity, it does not indicate whether these projects are utility owned and operated, or whether they are independent power projects. Neither does it differentiate between traditional projects financed by the members of the Organisation for Economic Co-operation and Development or those that have been supported by new sources of financing such as China. The authors have therefore complemented these data with detailed project-level data on independent power projects and Chinese-financed projects.
2. This figure is based on the date of financial close and not the commercial operation date; it includes all projects that reached financial close in 2014.
3. By 2015, South Africa had contracted 92 renewable energy IPPs totaling 6,327 MW and US$19 billion in investment, although the 26 projects of round 4 had still to reach financial close.
4. Projects included in this tally are all grid-connected IPPs with a capacity of 5 MW and greater. A complete list is provided in appendix A. Although Zimbabwe has three hydropower IPPs, these projects are all under 5 MW and are therefore excluded here.
5. A further 2,189 MW was awarded in 2015.
6. Between April and June 2015, South Africa announced the award of an additional 26 projects totaling 2,205 MW.
7. Many of the deals concluded in recent years were for hydroelectric plants that, as of 2014, had not yet reached their commercial operation date (COD). Hence, there is a discrepancy with the data in table 2.4, which includes only megawatts that are operational.
8. Unlike IPPs, which follow a strict sequence of financial close and then construction, Chinese-funded generation assets may commence construction before financial close, due to financing arrangements with "cooperation banks" as described in the next section.
9. Large hydropower is defined here as >50 MW.

10. For the purpose of this study, ODA is defined as flows to countries and territories on the OECD (Organisation for Economic Co-operation and Development) Development Assistance Committee's list of ODA recipients (available at http://www.oecd.org/dac/stats/daclist.htm) and to multilateral development institutions that are provided by official agencies, including state and local governments, or by their executive agencies; that aim to promote the economic development and welfare of developing countries; and that are concessional in character and have a grant element of at least 25 percent (calculated at a rate of discount of 10 percent) (http://www.oecd.org/investment/stats/officialdevelopmentassistancedefinitionandcoverage.htm).
11. Investment in IPPs includes private equity and loans from commercial banks, as well as flows from DFIs oriented toward the private sector, such as the International Finance Corporation, the Netherlands Development Finance Company (FMO), the German Investment and Development Corporation (DEG), Proparco, the Norwegian Investment Fund for Developing Countries (Norfund), and exim banks, among others. DFIs' commercially priced investments in IPPs are included in the IPP total. Concessionary grants and loans from DFIs and multilateral finance institutions are included in the ODA total.
12. Data on the financing of IPPs and Chinese-funded projects are most often available at the time of financial close. ODA data include funding *commitments* made in specific years (which could be graphed conveniently alongside IPP and Chinese funding data); however, these funding commitments do not have the same degree of certainty as financial close figures and there is often a large discrepancy between ODA commitments and disbursements. Therefore, this report relies on disbursements. ODA project disbursements were frontloaded to the first date to be consistent with IPP and Chinese data. Because most government and utility data are derived (as described in the text), and the EIA total installed megawatt figures correspond to COD and not to the financial close dates used for IPPs and Chinese-funded investments, or the ODA disbursement dates, it is difficult to form an accurate picture of government and utility funding year by year. These funding sources have therefore been excluded from figure 2.11.
13. Although Bujagali still represents the largest private hydropower installation, taking into consideration all renewables, Bujagali has been surpassed by the 300 MW Lake Turkana project in Kenya at $861 million.
14. Angola, Nigeria, and Zambia, despite having a noninvestment speculative grade, have all issued bonds since 2011 (Mecagni and others 2014: 8–10).
15. As noted previously, the discrepancy in figures is further exacerbated by the fact that table 2.4 records only megawatts installed.

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CHAPTER 3

Factors that Support Independent Power Projects and Their Success

Introduction

How do we account for the power investment trends outlined in the previous chapter? Why have some countries been more successful than others in attracting private investment? What are the key elements of the enabling environment for independent power projects (IPPs)? To what extent does the structure of a power sector affect the levels and rate of investment in new power generation capacity? What are the other key factors that can facilitate investment in new capacity?

This chapter explores the enabling environment for IPPs. First it examines the 20-year experience of power sector reforms on the African continent. Despite an ambition to unbundle and privatize the electricity industry and introduce competition, a very different reality persists. In most African countries, the state still controls the power sector, often through the presence of a dominant national utility. Meanwhile, massive needs for new investment, especially in power generation, greatly exceed the funding capacity of governments or national utilities and mean that private sector participation is imperative.

Within this context, IPPs have arisen in a number of countries, and in power sectors with various levels of unbundling and sector reforms. While this track record suggests that traditional reforms are not an absolute precondition for attracting IPPs, reforms that improve overall sector governance, strengthen the enabling environment, improve financial sustainability, reduce perceived risks by prospective investors, and improve competition will facilitate and accelerate investment.

Elements that appear to be particularly important in supporting IPPs include least-cost power expansion planning, effective procurement and contracting processes, and ensuring the financial health of off-taker utilities.

Power Sector Reforms and Independent Power Projects

Reforms and Emerging Power Sector Market Structures in Sub-Saharan Africa

Following earlier reforms in the power sectors of industrial countries and emerging markets, developing countries were encouraged to unbundle their electricity utilities and to introduce competition and private sector participation. Reforms were pursued to address poor financial and technical performance. Reform efforts also sought to introduce a space for private participation, as the public sector was no longer able to provide the requisite funds for system expansion (Jamasb 2002: 1–2; Gratwick and Eberhard 2008b).

At the outset, it was advised that the state-owned utility be transformed into a separate legal entity, through corporatization. Thereafter, this new entity, which was distinct from any government ministry and had all the associated company rights and obligations (including governance, labor, and budgetary management), was to undergo "commercialization." Such reforms were intended to address the root cause of many of the troubles faced by developing-country utilities and move them toward cost-recovery in pricing and improvements in metering, billing, and collections. Concurrently, the passage of the requisite energy legislation was to provide a legal mandate for restructuring, as well as the legal framework to allow private and foreign participation (including ownership) in the sector. Provision was also made for an independent regulator to introduce efficiency, cost-reflectivity, transparency, and fairness in the management of the sector, encourage appropriate investment, and protect consumers.

Further reform steps included unbundling, privatization, and competition—although it was not always apparent whether these were appropriate for specific countries. Vertical unbundling of the incumbent utility was proposed to separate the potentially competitive generation businesses from the natural monopoly of transmission and distribution (T&D) components. The horizontal unbundling of generation was meant to create competition by facilitating power trade through a power exchange, spot market, or bilateral contracts. Private investment was encouraged, in the form of IPPs with long-term contracts, and through full divestiture and the privatization of assets.

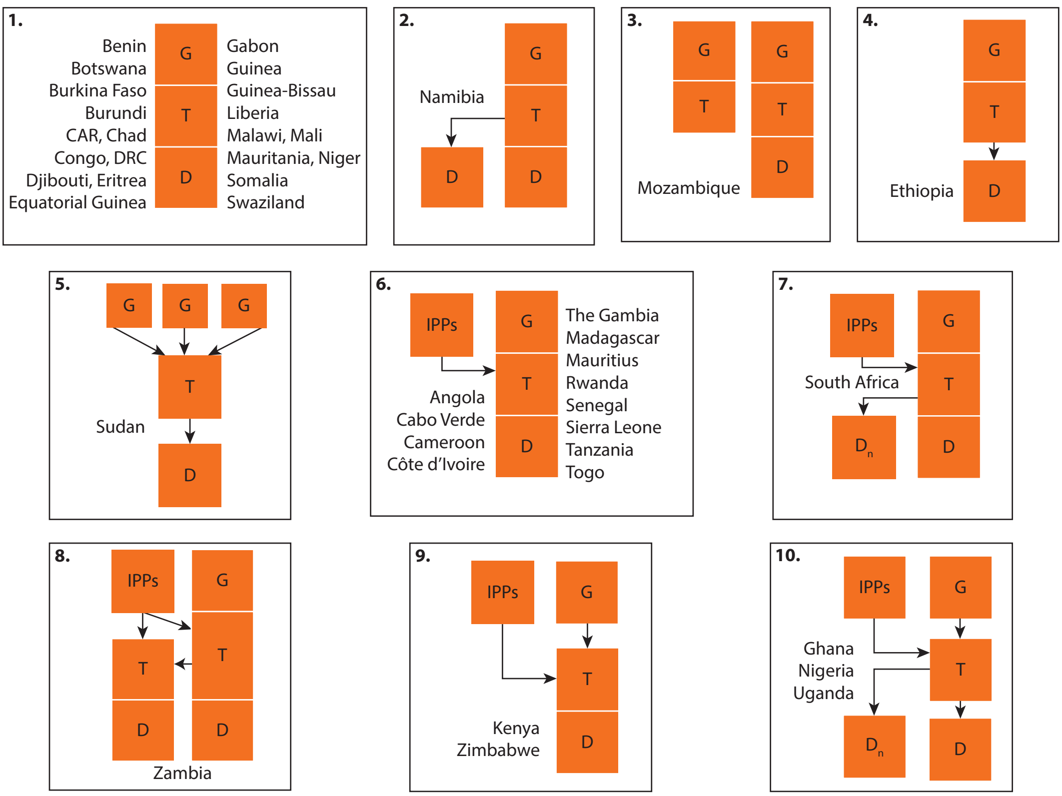
Over the course of the past two decades, power utilities in Africa were corporatized and steps were taken toward greater commercialization. Numerous countries passed energy laws providing for third-party access to grids and new regulatory institutions; many others also adopted IPPs. However, the reform measures stop here, with little achieved in terms of full unbundling (vertical or horizontal), privatization, and the introduction of wholesale and retail competition (Gratwick and Eberhard 2008a: 315–16).[1]

While Nigeria appears to be moving toward wholesale competition, having unbundled and privatized its utility and established a bulk electricity trader, the latter is still not operational. Other countries, such as Ghana, are considering moving to wholesale competition, but full implementation may be far off. The stated intentions of a number of African countries—including South Africa, Tanzania,[2] Zambia, and Zimbabwe—to introduce market competition have not materialized.

As of 2014, of the 48 Sub-Saharan countries, 21 had state-owned and vertically integrated utilities (that is, with generation, transmission, and distribution combined) with no private sector participation (figure 3.1, model 1).[3] The second-largest group of countries (model 6) also had vertically integrated state-owned utilities but, in addition, had introduced IPPs. A much smaller group of countries had unbundled power generation from T&D, and also incorporated IPPs (models 7–10).[4]

The unbundling of generation from T&D was initially understood as a key reform element, and one that arguably should even precede the introduction

Figure 3.1 Electricity Sector Structures: Sub-Saharan Africa, 2014



Source: Compiled by the authors, based on various primary and secondary source data.
Note: Includes vertical integration or unbundling of generation (G), transmission (T), and distribution (D) and presence of IPPs. While there are 48 Sub-Saharan African countries, the Comoros, Lesotho, São Tomé and Príncipe, and the Seychelles are excluded from figure 3.1. Thus the three island states are not included, along with Lesotho, where the national utility, Lesotho Electricity Company (LEC), has only T&D assets. A separate generation plant, the Muela Hydroelectric Station (72 MW), is owned and operated by the Lesotho Highlands Development Authority (owned by the government of Lesotho). These countries otherwise form part of the overall analysis. It should be noted that Kenya also has an unbundled transmission company, the Kenya Electricity Transmission Company Limited (KETRACO), which is responsible for new transmission assets. Furthermore, Uganda has one large, privatized distribution utility supplied from the transmission grid and some regional distribution companies not connected to the main transmission grid. Finally, some of the countries listed in model 1 can, in principle, allow private investments, but as of yet do not have IPPs. CAR = Central African Republic; Congo = Republic of Congo; DRC = Democratic Republic of Congo; IPP = independent power project; MW = megawatt; T&D = transmission and distribution.

of IPPs to ensure fairness in the contracting and dispatching of IPPs (versus the off-taker utility's own generation). This sequencing, however, is not fully reflected in the power sector structures on the ground. The majority of IPPs are in countries with vertically integrated utilities. In only six countries—namely, Ghana, Kenya, Nigeria, Uganda, Zambia,[5] and Zimbabwe—do the unbundling of utility generation and the introduction of IPPs go hand in hand.

Sudan has unbundled generation, but has no IPPs. Other countries, such as Ethiopia, Ghana, Namibia, Nigeria, South Africa, and Uganda, have separate distribution companies, but this level of unbundling is of less importance in creating equal opportunities for state utilities and IPPs, unless distributors are procuring generation capacity directly.

Do Power Market Structures Matter in Attracting Independent Power Projects?

Despite an ambition to unbundle and privatize the electricity industry and introduce competition, outcomes have not been as far-reaching as the plans set down on paper.

As seen in the power sectors of many Sub-Saharan African countries, the incumbent state-owned utility often remains intact and dominant, even as IPPs are invited into the market. In many cases, the incumbent state-owned utility may at a later stage also invest in new generation capacity. Thus, the model that has emerged is fundamentally a hybrid market, where public and private investment coexist. The characteristics of such power markets need to be recognized explicitly, as they present an array of new and unanticipated challenges related to generation planning and in particular to allocating new investment opportunities, ensuring timely initiation of competitive bidding processes, establishing institutional capacity to contract effectively, and ensuring fair and transparent power dispatch arrangements.

Implementation of either wholesale or retail competition has also been very limited. Such competition requires sophisticated legal and financial infrastructure, which is often inadequate in many developing countries. Even with the infrastructure in place, the market may not send the signals needed for the requisite investment.

It is possible that almost half of the reform measures typically prescribed are not necessarily relevant to the conditions on the ground in most developing countries. In addition, as the previous section shows, there is no clear correlation between the degree of unbundling and the presence of private investment in the form of IPPs, although it seems logical that where the national utility is still investing in new generation capacity, its unbundling would have the effect of leveling the playing field for new IPPs. The next section will also highlight that IPPs are not necessarily correlated to the presence of an independent regulator.

In sum, the analysis shows that IPP investments have arisen in a variety of power market structures, characterized by various degrees of reform.

This does not mean the traditional elements of power sector reform—such as unbundling, independent regulation, privatization, and competition—are unimportant or irrelevant. As has been observed, reforms remain important as long as they improve sector governance and the enabling environment for IPPs. They also serve to boost a country's credibility—or reduce the risk perceived by power sector investors. This is a key positive externality that can ultimately lead to more sustainable contract arrangements. There will also be instances where private participation can improve utility performance. Where there are real conflicts between state-owned generation and the procurement of IPPs, unbundling generation from the transmission company and system operator or market operator might make sense. And competition for the market remains critical.

The power sectors in African countries face two enduring challenges. First is to accelerate investment in generation capacity to power economic development. Second is to improve the performance of utilities so that they are creditworthy purchasers of power from IPPs and can also deliver electricity services on a sustainable basis. In response to these challenges, focus on planning, procurement, and contracting practices for new generation investment must be renewed and, simultaneously, improvements need to be made to the performance of distribution utilities.

An important lesson is provided by the second wave of power sector reforms to occur in regions such as Latin America (see chapter 4). There, the traditional reform model was tweaked to attract adequate investment in new power generation capacity, especially in capital-intensive technologies such as large hydroelectricity and also in new, renewable technologies such as wind energy. Most Latin American countries had undergone a process of unbundling, privatization, and the establishment of wholesale spot markets. Even so, it became clear that long-term contracts with financially viable off-takers were critical to generate secure and reliable financial flows to pay for large investments. A second wave of reforms—as enacted in Brazil, Chile, Colombia, Panama, and Peru—shifted emphasis from prescriptions regarding unbundling, privatization, and the creation of wholesale markets (competition *in* the market), to the establishment of dynamic plans for long-term generation and transmission expansion. This was linked to the timely initiation of competition *for* the market—through the auction of long-term power contracts backed by creditworthy off-takers. Of particular importance were efforts to improve the technical and financial performance of electricity distribution: unless a utility operates efficiently, and sufficient revenue is being collected to pay for operations and investment (including contracts for power), sector reforms cannot meet their objectives.

Africa has not progressed as far as Latin America and other regions in the privatization and establishment of wholesale electricity markets; nevertheless, it can learn from Latin America's second wave of reforms, in particular the practices and tools used to attract sources of new investment in power generation capacity—and to foster competition among them.

The Importance of Independent Regulation

By definition, IPPs are investment transactions regulated by the underlying contracts, most notably the power purchase agreement (PPA). Regulations at the sector level, although they do not directly influence the details of these contracts, are important in defining the rules of the game and ultimately shaping the enabling environment for IPPs. Regulators approve PPAs and issue licenses to new power projects.

The most widespread power sector reform element in Sub-Saharan Africa has been the establishment of independent energy/utility regulators. As of 2014, 27 countries, or more than 50 percent of all Sub-Saharan African countries, had established such agencies (table 3.1).

The countries with the most IPPs—for example, Uganda, Kenya, Senegal, Nigeria, Tanzania, Ghana, Cameroon, and Côte d'Ivoire—all have electricity regulators (table 3.1). The presence of such an agency is not a sufficient condition for attracting IPPs, however, as seen by the countries with a regulator but no IPP. The quality of regulation, meanwhile, is critical. If regulatory governance is transparent, fair, and accountable, and if regulatory decisions are credible and predictable, there is greater certainty around market access, and tariffs and revenues—with potentially positive outcomes for the host country and investors alike. The corollary is that inexperienced regulators with insufficient capacity may make arbitrary decisions that might serve to increase regulatory risk and deter investment.

An independent regulator brings with it oversight capacity and could potentially enforce the competitive procurement of IPPs. This is largely recognized as a best practice, as will be discussed at length in the next chapter. In nearly all of

Table 3.1 Sub-Saharan African Countries with Independent Electricity/Utility Regulators, by Year Established

Year regulator established	*Country*
1994	South Africa
1997	Zambia
1998	Cameroon, Côte d'Ivoire, Senegal
1999	Niger, Uganda
2000	Ghana, Mali, Namibia, Togo
2001	The Gambia, Mauritania, Rwanda, Tanzania
2003	Zimbabwe
2004	Lesotho, Mozambique
2005	Nigeria
2006	Kenya
2007	Angola, Malawi, Swaziland
2010	Burkina Faso, Gabon
2011	Sudan
2014	Ethiopia

Sources: Based on authors' data, African Forum for Utility Regulators, and IRENA 2012.

the five case study countries, competition has been enshrined in legislation and/or regulations, with the regulator at the helm (box 3.1). Much of the relevant legislation, however, has come into effect only recently after considerable planning and procurement mishaps, and is not foolproof. For example, Kenya, Tanzania, Uganda, and Nigeria have seen directly negotiated projects even after the advent of the regulator.

Overall, the presence of a regulator is not necessarily associated with more competitive procurement practices, and regulators have not always ensured that captive electricity consumers benefit from the pass-through of competitive generation prices. Also, the independence of regulators may be compromised by overreaching and competing government agencies. In many countries, the independence and professional capacity of regulators need to be strengthened so that they can discourage directly negotiated generation contracts and instead enforce the rules for the competitive procurement of IPPs.

Box 3.1 Legislation to Promote Sector Competition: Examples from Five Countries

In Kenya, through the 2006 Energy Act, the regulator is charged with ensuring the implementation and the observance of the principle of fair competition in the energy sector, in coordination with other statutory authorities (Clause 5). As stated in the 2013 Public Procurement and Disposal Act, the procuring entity shall open tendering (29 [1]).

In Nigeria, the regulator mandated competitive tenders through its Regulations for the Procurement of Generation Capacity, published in 2014.

In South Africa, Section 217 of the Constitution requires that when an organ of state procures goods and services it must do so in accordance with the principles of fairness, equitability, transparency, competitiveness, and cost-effectiveness. This constitutional requirement is echoed in section 51(1)(a) of the Public Finance Management Act of 1999.

In Tanzania, the Electricity Act gives the Energy and Water Utilities Regulatory Authority (EWURA), the Tanzanian regulator, powers to approve the initiation of procurement of power projects. These powers have been further defined under "The Electricity (Initiation of Power Procurement) Rules," with the overarching goal to discourage the development of unsolicited proposals that fall outside the Power System Master Plan and are not financially viable for the state (EWURA, per com, 2014; Electricity Act [CAP 131]). The rules came into effect as of January 1, 2015, and will impact on projects presently under negotiation, but not existing IPPs (that is, Songas and Independent Power Tanzania Ltd., IPTL).

In Uganda, the relevant guidelines are less explicit, though the regulator is vested with managing the process. For any independently promoted projects across all generation types, the Electricity Regulatory Authority (ERA) can receive unsolicited bids (Section 30 of the Electricity Act 1999) or implement competitive bidding processes for concessions pursuant to Section 33 of the Electricity Act (1999). For all unsolicited bids, ERA is the focal entity and guides and monitors the planning and implementation of projects.

Source: Compiled by the authors, based on various primary and secondary source data.

The Importance of Planning, Procurement, and Financial Sustainability

Generation Planning in Hybrid Power Markets

The most comprehensive planning tools are the Least Cost Power Development Plan (LCPDP) or, more broadly, the Integrated Resource Plan (IRP), which includes both generation and transmission planning, and identifies the supply- and demand-side investments needed to meet projected electricity demand at the least total cost (that is, the net present value [NPV] of investments, operating costs, and costs of unsupplied energy) over a certain period (typically 15–20 years), while also meeting associated policy objectives such as environmental sustainability.

In the past, the incumbent state-owned power utility generally assumed responsibility for generation expansion planning. In many cases, these utilities ran into financial difficulties; investment costs were high, and tariffs were insufficient to fund the required new investment. Today, the majority of utilities in Africa are underinvesting: they simply do not have sufficient financial resources. As noted, growing pressure for power sector reforms has encouraged the entry of IPPs and new private investment that supplements the utilities' efforts. However, in these hybrid markets it is often unclear who is responsible for generation expansion planning.

There is a range of generation planning arrangements across Sub-Saharan African countries. While there is no one optimal solution, some key lessons may be observed.

If the planning function remains with the national utility, strong political leadership is crucial to ensure that the incumbent utility works with the state to achieve national goals and objectives. Alternatively, the planning function may be transferred to another institution—within the government, the regulator, or a new independent planning body—or attached to an unbundled, independent transmission and/or system operator. If this transfer is to be successful, the planning function needs to be properly resourced in terms of people, software, and institutional capacity. The majority of Sub-Saharan African countries have inadequate capacity and end up contracting out this function to consultants. Master plans for least-cost generation expansion are produced but are often not implemented. Tanzania is a case in point—it has a master plan but this is not fully used in practice. Meanwhile, the country still experiences power shortages, as do many other countries in the region.

Although the institutional location of power sector planning is important, equally important is the nature of that planning. Planning needs to be up to date and flexible to ensure security of supply, a least-cost mix of generation plants, and the right combination of exports and imports. South Africa's electricity plan (the IRP 2010–30) is widely recognized as being out of date, with optimistic demand projections and incorrect cost assumptions. Nevertheless, the plan has continued to be used as a basis for power procurement and investment decisions, with the risk that too much capacity of the wrong kind might be procured.

Effective planning also involves broad stakeholder participation. Kenya, for example, has adopted a planning approach that involves a wide range of stakeholders through the membership of a planning committee chaired by the energy sector regulator. Broad buy-in to the planning process ensures that stakeholders properly understand the challenges and costs of developing new sources of power, and creates investor interest.

Generation Procurement

Electricity plans need to be translated into timely procurement and well-delineated investment opportunities for the private and public sectors. Unfortunately, few African countries have an explicit connection between planning and procurement.

South Africa is one of the few countries that *do* have such a connection. The Electricity Regulation Act, and subsidiary new generation regulations, empower the minister of energy to determine not only how much new power generation capacity is needed, but also what type should be built, and when, and by what party. Yet South Africa, like most other Sub-Saharan African countries, lacks clearly stated criteria for the allocation of investment opportunities between state-owned enterprises (SOEs) and IPPs. In Ghana, IPP investments have been negotiated with the Volta River Authority (VRA), the Electricity Company of Ghana (ECG), and the Ministry of Energy, with all three entities entering separate purchase agreements with potential IPPs. Each entity has followed different processes, with little regard for national procurement procedures.

A key feature of power generation procurement in Africa is the low recourse to competitive bidding, despite the fact that this is frequently enshrined into legislation. A disproportionate share of IPPs in Africa is developed based on unsolicited proposals and through direct negotiation. The causes behind this phenomenon and the various advantages, disadvantages, and outcomes of unsolicited and directly negotiated projects versus competitive bidding will be extensively investigated in chapter 4. Weak linkages between planning and procurement, inadequate or incomplete regulations, and the absence of a procurement authority, as outlined earlier, all contribute to the problem and will be further discussed. It should be noted that even where good regulations and practices exist, without enforcement there is little hope that procurement will be run efficiently.

When countries—often finding themselves short of power—opt for direct negotiation and/or are confronted with numerous unsolicited proposals from power developers, more attention needs to be devoted to ensuring that they achieve value for money. For example, Kenya Power once had robust processes for testing the merits of unsolicited proposals, using a range of analytical techniques. Its methods included “open book” processes, prespecifying a capital structure for the project and expected returns on debt and equity, and comparing the resulting prices to other pricing benchmarks—such as feed-in tariffs (FiTs) and the prices resulting from competitive procurements. The energy regulator also undertook a separate review of value for money. Importantly, these processes consider the combined impact of project prices and risks.

Meanwhile, FiTs have emerged as an alternative procurement mechanism in a number of Sub-Saharan African countries, including Angola, Ghana, Kenya, Nigeria, Rwanda, Senegal, Tanzania, and Uganda. FiTs have mostly been used for the procurement of grid-connected renewable energy. Standard power purchase tariffs are published by the regulator and have the advantage of offering investors simplicity and price certainty. However, regulators may set FiTs too high, and the potential advantages of lower prices from competitive tenders might be missed.

Generation Contracting

In most cases, IPP contracts extend over a long period of time; the typical contract is for 15 to 30 years. This large time frame is considered both a strength and a weakness. Predictable revenue streams allow equity risk capital to be rewarded, and sponsors can also service debt with long tenors. Conversely, in an environment of power market reform, both parties can encounter problems with fixed long-term take-or-pay contracts if the various conditions under which the contracts are agreed upon change. While all contracts between IPPs and utility off-takers described in this book have been in the form of long-term PPAs, the legal and regulatory frameworks surrounding the making of these contracts differ, resulting in diverse outcomes across the region's power sectors. Governance frameworks, which shape the degree of predictability and risk in the sector, ultimately impact on investment and development outcomes.

Governments and national utilities require a great deal of specialized expertise to negotiate robust and competitive contracts. Private sponsors often hire the best legal, financial, and technical transaction advisers; governments rarely do so. To plug this gap, governments need to allocate clear responsibility to either the national utility or a government agency. If the national utility is to be responsible, then it is also critical that a ring-fenced contracting function be established, separate from the utilities' own generation or new build function. The best location may be an independent system operator that also takes responsibility for planning and may then be integrated with the procurement function. In this case, the system operator assumes responsibility for both the system's short-term balance and the long-term security of supply.

Creditworthiness of Off-Takers

At the crux of the investment conundrum is the financial viability of the off-taker. High T&D losses, tariffs below cost-recovery levels, and poor billing and collections are key issues that can severely affect the financial standing of utilities. Average distribution losses in Sub-Saharan Africa are 23 percent compared with the commonly used norm of 10 percent or less in developed countries. Moreover, average collection rates are only 88.4 percent compared with the best practice of 100 percent. Combining the costs of distribution losses and uncollected revenue and expressing them as a percentage of utility turnover provides a measure of a utility's inefficiency. In Africa, this inefficiency is equivalent, on average, to 50 percent of turnover (Eberhard and others 2011: 134).

At the sector level, governance reforms can critically improve the performance of state-owned utilities. Governance may be assessed using various criteria, including ownership and shareholder quality, managerial and board autonomy, accounting standards, performance monitoring, outsourcing to the private sector, exposure to labor markets, and the discipline of capital markets. Most utilities in Sub-Saharan Africa meet only about half of the criteria for good governance (Eberhard and others 2011: 137).

At the operational level, practices targeting technical and commercial efficiency can critically improve the financial standing of a utility in a short period of time. To reduce losses and protect revenues, utilities must take better control of technical losses, enhance service delivery, and improve billing and collection. Such actions are especially important as a utility approaches an IPP transaction. If the utility is financially fragile and is not collecting enough revenues, then the payment of power generators could be threatened. Robust PPAs have therefore become a requirement for new investors seeking to safeguard payment streams (that is, regardless of the financial health of the off-taker). PPAs denominated in U.S. dollars or euros, bolstered by credit enhancements and security measures, have been necessary to seal the deal for the majority of IPPs in Sub-Saharan Africa over the past two decades.

While most arrangements have been honored, there is evidence that contracts have unraveled when terms were considered untenable by country stakeholders, as seen in the case of Tanzania's IPTL (Independent Power Tanzania Ltd.) and Nigeria's AES Barge, both of which went to arbitration. Thus, even robust PPAs and security arrangements are not ironclad, and issues must be anticipated from the outset during the procurement process.

A Framework for Understanding the Enabling Environment for IPPs

After documenting and analyzing IPPs in Sub-Saharan Africa over a decade, researchers have compiled a list of the elements seen to contribute to sustainable IPP investments (table 3.2). Some of the elements may be grouped into areas over which the host-country government has immediate influence, and include issues such as policy, regulation, planning, and competitive procurement. The balance of issues may be considered as being within the project purview. The list outlined here is not exhaustive, but provides a sketch of best practices for developing IPPs in Sub-Saharan Africa (Eberhard and Gratwick 2011).

At the country level, the overall economic conditions and legal framework are clearly relevant, as are policies that encourage private investment in general and in the power sector in particular. Stable macroeconomic policies, investment protection, respect for contracts, capital repatriation, tax incentives, and further IPP investment opportunities will attract more capital at lower cost. Transparent, consistent, and fair regulatory oversight, with a commitment to cost-reflective tariffs, provides more price and revenue certainty, boosting the creditworthiness of off-takers and thus requiring less risk mitigation. And we have already

Table 3.2 Factors Contributing to Successful Independent Power Project Investments, Sub-Saharan Africa

Factor	*Details*
Country level	
Stable country context	Stable macroeconomic policies
	Legal system allows contracts to be enforced, laws to be upheld, arbitration
	Good repayment record and investment-grade rating
	Previous experience with private investment
Clear policy framework	Framework enshrined in legislation
	Framework clearly specifies market structure and roles and terms for private and public sector investments (generally for a single-buyer model, since wholesale competition is not yet seen in the African context)
	Reform-minded "champions" to lead and implement framework with a long-term view
Transparent, consistent, and fair regulation	Transparent and predictable licensing and tariff framework Cost-reflective tariffs Consumers protected
Coherent power sector planning	Power-planning roles and functions clarified and allocated
	Planning function skilled, resourced, and empowered
	Fair allocation of new build opportunities between utility and IPPs
	Built-in contingencies to avoid emergency power plants or blackouts
Competitive bidding practices	Planning linked to timely initiation of competitive tenders/auctions Competitive procurement process adequately resourced and fair/transparent
Project level	
Favorable 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
Favorable debt arrangements	Competitive 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)
Creditworthy off-taker	Adequate managerial capacity
	Efficient operational practices
	Low technical losses
	Commercially sound metering, billing, and collections
	Sound customer service
Secure and adequate revenue stream	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, and so on)
	Security arrangements where necessary (escrow accounts, letters of credit, standby 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)

table continues next page

Table 3.2 Factors Contributing to Successful Independent Power Project Investments, Sub-Saharan Africa *(continued)*

Factor	*Details*
Credit enhancements and other risk management and mitigation measures	Sovereign guarantees Political risk insurance (PRI) Partial risk guarantees (PRGs) International arbitration
Positive technical performance	Efficient 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 a good image in the country through political relationships, development funds, effective communications, and strategically managing their contracts, particularly in the face of exogenous shocks and other stresses

Source: Adapted from Eberhard and Gratwick 2011.
Note: DFI = development finance institution; IPP = independent power project; O&M = operations and maintenance; PPA = power purchase agreement; ROE = return on equity.

mentioned the benefits of power planning and timely initiation of competitive tenders or auctions for new capacity.

At the project level, debt and equity finance has to be appropriately structured and serviced through revenue guaranteed in a robust PPA and backed with required credit enhancement and security arrangements, including guarantees, insurance, and other risk mitigation instruments.

The Performance of Five Countries

Table 3.3 summarizes the features of the power sectors of the five case study countries, with a focus on those elements relevant to supporting IPPs.

Of the five countries, South Africa clearly has the best investment climate, a policy for expanding renewable energy, a power plan linked to a series of competitive tenders, and a set of standardized contracts backed by a sovereign guarantee. The country has an independent regulator, although its decisions have not always been consistent. It could be argued that utility tariffs do not fully reflect costs; nevertheless, the regulator has mandated the full pass-through of IPP costs. The consequence has been a highly successful IPP program where more megawatts and investment have been contracted in four years than in the previous two decades across the rest of Sub-Saharan Africa. Remarkably, this has been achieved within an electricity sector that is dominated by a large state-owned vertically integrated utility that relies mostly on coal and once was not receptive to IPPs.

Kenya has an investment climate that is better than that of neighboring Tanzania and Uganda, as well as Nigeria, and has been able to attract private investment at a lower cost than these countries. Its electricity sector has been

Table 3.3 Summary of Power Sector Features in Case Study Countries, Sub-Saharan Africa

Country	*Unbundled utility*	*Privatized utility*	*Wholesale competition*	*Independent regulator*	*Least Cost Power Development Plan (LCPDP)*	*Predominant procurement practices*
South Africa	No	No	No	Yes	Integrated Resource Plan for 2010–2030 out of date	Competitive
Kenya	Yes	No	No	Yes	LCPDP based on stakeholder consultations	Competitive
Tanzania	No	No	No	Yes	Electricity Supply Industry Reform Strategy and Roadmap, 2014–2025; LCPDP, 2013	Mostly direct negotiations (some previous tenders with limited competition)
Uganda	Yes	Partial[a]	No	Yes	2011 Power Sector Investment Plan not updated	Direct negotiations until advent of GETFiT (hybrid feed-in tariff with competitive tenders)
Nigeria	Yes	Partial[a]	Transitional market	Yes	System operator is mandated to prepare a power master plan but has not been updating it	Direct negotiations

Source: Compiled by the authors, based on various primary and secondary source data.
Note: GETFiT = global energy transfer feed-in tariff.
a. Uganda's main distribution utility is concessioned to a private company, as is the previous state generation utility. Transmission remains public. There are also some small private regional concessions not connected to the main transmission grid. In Nigeria, the distribution companies have been privatized, as have many of the generation companies, but the transmission utility remains publicly owned, albeit under a private management contract.

unbundled, it has an independent regulator, and it once had a clear power-planning process and a competent procurement capability in the Kenya Power and Lighting Company (KPLC), the T&D company. The regulator has helped move tariffs to cost-reflective levels, and the KPLC has been reasonably creditworthy. The consequence is a series of competitive procurements with steadily better price outcomes.

Tanzania on the other hand has a weaker investment climate, some ambivalence around private sector investment, a vertically integrated state-owned utility with technical and financial performance challenges, and poor planning and procurement practice—despite a regulator that seeks to encourage more transparent and competitive procurement. Tanzania has relied more on unsolicited bids and direct negotiations than on competitive tenders. As a result, some IPPs here stand out for their high prices and controversial contracts.

Uganda's recent success has relied less on its overall investment climate and more on a clear power sector structure and a recent competitive tendering program for small renewable energy power plants. With its power sector unbundled, IPPs contract directly with the transmission company, free of conflicts with state-owned generation, and the privately concessioned distribution company is increasingly more effective in reducing losses and improving its financial viability. The dedicated global energy transfer feed-in tariff (GETFiT) intervention (analyzed at length in the next chapter) has provided transaction advice and support for running competitive tenders coupled with standardized contracts. It remains to be seen whether this initiative can be sustained in the future.

Nigeria's investment climate is challenging; its previous success with IPPs had less to do with a clear policy framework and more with strong political will at the highest levels. A protracted and torturous power sector reform process—including full unbundling, privatization, and, eventually, competition—has, in the short term, probably made it harder to secure investments in new IPPs. It is hoped that, eventually, the reform process will improve the financial viability of the sector, and Nigerian Bulk Electricity Trading (NBET) will become a dependable and attractive off-taker for IPPs.

This analysis of the case study countries reveals no single or consistent element that guarantees IPP investment. Planning and competitive procurement practices are important; creditworthiness of off-taker utilities is also critical, but policy makers should not lose sight of the broader investment, policy, and regulatory climate.

Notes

1. The one minor exception is the Southern African Power Pool, where nominal cross-border trades are made either through bilateral contracts or through a day-ahead market. Such trades, however, constitute a fraction of the total electricity produced in the region.
2. In Tanzania, however, the goal of full-scale privatization by 2024 exists on paper but may not be possible to achieve in practice.
3. These countries tend to have smaller systems, of 280 MW on average. If the Democratic Republic of Congo is excluded, this average falls to 170 MW.
4. The exceptions are Sudan and Ethiopia, but IPPs will soon be present there, too.
5. Zambia's national utility, ZESCO Ltd., remains vertically integrated, but a separate and private transmission company, Copperbelt Energy Corporation, is also investing in IPPs.

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CHAPTER 4

Independent Power Projects: An Analysis of Types and Outcomes

Introduction

Previous chapters have indicated the important and growing contribution of independent power projects (IPPs) to Africa's power generation mix. Again, for the purposes of this study, IPPs are defined as power projects that are, in the main, privately developed, constructed, operated, and owned; have a significant proportion of private finance; and have long-term power purchase agreements (PPAs) with a utility or another off-taker. Within this broad definition there are many variants: IPPs differ in their ownership and financing structures, in technology choices and risk profiles, in how they are procured and contracted, and in risk mitigation mechanisms.

Most IPPs are wholly privately owned, though several involve public coinvestment. Most IPPs are developed within special-purpose vehicles (SPVs) and rely on nonrecourse, project funding. A few are financed off the balance sheets of large corporations. Debt and equity structures differ.

The first IPPs in Sub-Saharan Africa were thermal (diesel, heavy fuel oil [HFO], or gas), but some hydroelectric IPPs exist. These are joined, in growing numbers, by new renewable energy technologies such as wind and solar. The various project types have different risk mitigation measures—related, in part, to technology and fuel choices, but also, crucially, to the creditworthiness of off-takers and investors' assessments of payment risks.

IPPs may result from direct negotiations between IPP developers and governments or utility off-takers, or may be procured through international competitive bids (ICBs), with very different investment and price outcomes.

This chapter presents an analysis of the different types of IPPs. First, ownership and financing structures are discussed, with the role of development finance institutions (DFIs) highlighted; next, the range of risk mitigation measures associated with different IPPs is outlined; then the growth in solar and wind IPPs is noted; and finally the different procurement and contracting mechanisms for IPPs are considered.

Table 4.1 Independent Power Projects in Five Selected Countries, Sub-Saharan Africa, 1994–2014

Country	*No. of projects*	*Capacity (GW)*	*Total investment (US$, millions)*
Kenya	11	1.07	2,328
Nigeria	4	1.52	1,702
South Africa	67	4.31	14,435
Tanzania	4	0.43	598
Uganda	11	0.45	1,274
Total	**97**	**7.77**	**20,337**

Source: Compiled by the authors, based on various primary and secondary source data.
Note: GW = gigawatt.

A large part of the analysis focuses on assessing and comparing competitively procured versus directly negotiated projects. A lack of competition in the procurement and contracting of IPPs is a common feature of African power sectors, and this chapter tries to unpack the reasons behind such a phenomenon, and the associated implications.

The analysis in this chapter is based primarily on the in-depth case studies carried out in Kenya, Nigeria, South Africa, Tanzania, and Uganda, included as separate chapters. Altogether, these countries account for 97 out of the 126 existing IPPs, with a cumulative capacity of 7.8 gigawatts (GW) (equal to approximately 70 percent of the total IPP capacity) and $20.3 billion of investments (equal to 80 percent of the total IPP investment in Sub-Saharan Africa) (table 4.1).

Among the case study countries, South Africa has embarked on the most ambitious renewable energy IPP program, which will soon be followed by thermal IPPs. Nigeria is undergoing the most extensive power sector reforms on the continent. While other countries might not be able to replicate the experiences of these two major economies, there are many lessons that can be adapted and applied. Kenya and Tanzania provide a fascinating opportunity to contrast the experiences and outcomes of solicited versus unsolicited bids. Tanzania is also about to start more ambitious reforms and will expand its gas-to-power investments, while Kenya is encouraging a diversified set of power investments, including renewable energy. Uganda has overhauled its electricity supply industry and has numerous small IPPs and the largest hydropower IPP in Sub-Saharan Africa.

Ownership and Financing Structures

There has been a wide variety of African IPP sponsors and debt providers, though a few have backed multiple projects. Table 4.2 highlights specific IPPs from the case study countries (excluding South Africa).

While state institutions have invested in some IPPs—for example, the Nigerian National Petroleum Corporation (Okpai and Afam) and the

Table 4.2 Independent Power Project Sponsors and Debt Holders in Case Study Countries (Excluding South Africa), Sub-Saharan Africa

Project	*Equity partners (country, % of equity held)*	*Procurement*	*Contract change Y = yes/N = no*	*Equity turnover (no.)*[a]
Kenya				
Westmont	Equity: Westmont (Malaysia, 100%); sought to sell plant since 2004; ultimately towed back to Malaysia Debt: equity financed	DN	Not extended	—
Iberafrica	Equity: Union Fenosa (Spain, 80%), Kenya Power Pension Fund (Kenya, 20%) since 1997 Debt: Union Fenosa ($12.7 million in direct loans and guaranteed $20 million); Kenya Power Pension Fund ($9.4 million in direct loans and guaranteed $5 million through local Kenyan bank)	DN	Y	0
OrPower4	Equity: Ormat (USA, 100%) since 1998 Debt: equity financed until 2009, European DFIs $105 million loan in 2009, then OPIC loan of $310 million drawn down in 2012–13	ICB	Y	0
Tsavo	Equity: Cinergy (USA) and IPS (Int'l) jointly owned 49.9%; Cinergy sold to Duke Energy (USA) in 2005, CDC/Globeleq (UK, 30%), Wartsila (Finland, 15%), and IFC (Int'l, 5%) retain remaining shares since 2000 Debt: IFC own account ($16.5 million), IFC syndicated ($23.5 million), CDC own account ($13 million), DEG own account (€11 million), DEG syndicated (€2 million)	ICB	N	1
Rabai	Equity: Aldwych International (Netherlands, 34.5%), BWSC (Danish, but owned by Mitsui of Japan, 25.5%), FMO (Netherlands, 20%), IFU (Danish bilateral lender, 20%) Debt: FMO ($126 million), Proparco and EAIF (25% each), DEG (15%), European Financing Partners (10%)	ICB	N	0
Mumias	Equity: Mumias Sugar Company Limited (100%/Kenya) Debt: not available	DN	N	0
Thika	Equity: Melec PowerGen (part of Matelec Group) (90%/Lebanon) Debt: AfDB (€28 million), IFC (€28 million), Absa Capital (€28 million)	ICB	N	0
Triumph	Equity: Broad Holding (Kenya), Interpel Investments (Kenya), Tecaflex (Kenya), Southern Inter-trade (Kenya)	ICB	N	0

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Table 4.2 Independent Power Project Sponsors and Debt Holders in Case Study Countries (Excluding South Africa), Sub-Saharan Africa *(continued)*

Project	*Equity partners (country, % of equity held)*	*Procurement*	*Contract change Y = yes/N = no*	*Equity turnover (no.)*[a]
Triumph *(cont.)*	Debt: Industrial and Commercial Bank of China (ICBC) ($80 million), and Kenya's CFC Stanbic Bank ($28 million) (of which Standard Bank is the parent, in which ICBC has a 20% stake)			
Gulf	Equity: consortium of local investors, namely Gulf Energy Ltd. and Noora Power Ltd.	ICB	N	0
	Debt: $76 million in long-term debt financing (IFC A Loan, and commercial lending through IFC B Loan and OPEC Fund for International Development)			
Kinangop	Equity: Aeolus Kenya, AIIF2, majority owner (South Africa/Mauritius), Norfund (Norway)	REFiT	N	0
	Debt: Kenyan CFC Stanbic project stalled			
Turkana	Equity: KP&P Africa BV (Netherlands) with Aldwych International (Netherlands)	DN	N	0
	Debt (foreign and local): AfDB, EIB, the Standard Bank of South Africa, Nedbank, FMO, Proparco, East African Development Bank (EADB), PTA Bank, EKF, Triodos, and DEG. The project's debt raising for the generation project was led by the AfDB, as mandated lead arranger, with the Standard Bank of South Africa and Nedbank as coarrangers			
Nigeria				
AES Barge	Equity: Enron (USA, 100%) sold to AES (95%) and YFP (Nigeria, 5%) in 2000	DN	Y	1
	Debt: $120 million loan (foreign and local): RMB (South Africa), FMO, African Export-Import Bank, Diamond Bank Nigeria, Fortis Bank, KfW, United Bank for Africa, African Merchant Bank			
Okpai	Equity: Nigerian National Petroleum Corporation (Nigeria, 60%), Nigerian Agip Oil Company (Italy, 20%), and Phillips Oil Company (USA, 20%) maintained equity since 2001	DN	Y	0
	Debt: 100% equity financed			
Afam VI	Equity: Nigerian National Petroleum Corporation (Nigeria, 55%), Shell (UK/Netherlands, 30%), Elf (Total) (France, 10%), Agip (Italy, 5%)	DN	N	0
	Debt: 100% equity financed			

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Table 4.2 Independent Power Project Sponsors and Debt Holders in Case Study Countries (Excluding South Africa), Sub-Saharan Africa *(continued)*

Project	*Equity partners (country, % of equity held)*	*Procurement*	*Contract change Y = yes/N = no*	*Equity turnover (no.)*[a]
Aba Integrated	Equity: Geometric Debt: senior debt: Diamond Bank (Nigeria) and Stanbic IBTC Bank (Nigeria); subordinated debt: EIB and EAIF	DN	N	0
Tanzania				
IPTL	Equity: Mechmar (Malaysia, 70%), VIP (Tanzania, 30% in kind); sold to Pan Africa Power Tanzania Ltd. (PAP) in 2013 (disputed) Debt: Bank Bumiputra and Sime Bank (Singapore); Standard Chartered Bank, Hong Kong (SCB-HK) bought debt, valued at $125 million, for $74 million (in 2005)	DN	Y	1
Songas	Equity: TransCanada sold majority shares to AES (USA) in 1999 and AES sold majority shares to Globeleq (UK) in 2003. All preferred equity shares were converted into "Loan Notes" in June 2009, only common shares remain Debt: IDA ($120 million), EIB ($50 million), assumed loans of $69.2 million from initial TANESCO plant	ICB	Y	2
Mtwara	Equity: Artumas Group Inc. (Canada, 100%), sold shares to Wentworth Group, which in turn sold to TANESCO in 2012 Debt: 100% financed with balance sheet of shareholders	ICB	Y	2
Symbion	Equity: built by Richmond, sold to Dowans, then to Symbion Debt: equity financed	DN	Y	2
Uganda[b]				
Bujagali	Equity: Sithe Global (USA, 58%), IPS-AKFED (32%), Government of Uganda (10%) Debt: IFC, EIB, Proparco, KfW, AfDB, FMO, DEG, Standard Chartered, Absa	ICB	N	0
Namanve	Equity: Jacobsen (Norway, 100%) Debt: Norwegian commercial bank and local Ugandan bank, and supported by the Norwegian Agency for Development Cooperation (NORAD)	ICB	N	0
Bugoye	Equity: TrønderEnergi, Norfund (Norway) Debt: EAIF/FMO	DN	N	0

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Table 4.2 Independent Power Project Sponsors and Debt Holders in Case Study Countries (Excluding South Africa), Sub-Saharan Africa *(continued)*

Project	*Equity partners (country, % of equity held)*	*Procurement*	*Contract change Y = yes/N = no*	*Equity turnover (no.)*[a]
Mpanga	Equity: South Asia Energy Management Systems (SAEMS) (USA, 100%)	DN	N	0
	Debt: EAIF, FMO, DEG			
Tororo	Equity: Electro-Maxx (Uganda, 100%)	DN	N	0
	Debt: funded by local Ugandan banks			
Ishasha	Equity: Eco Power Ltd. (Sri Lanka, 100%)	DN	N	0
	Debt: Sri Lankan commercial banks			
Buseruka	Equity: Hydromax Limited (Uganda, 100%)	DN	N	0
	Debt: African Preferential Trade Area Bank (PTA), AfDB			

Source: Compiled by the authors, based on various primary and secondary source data.
Note: Absa = South African commercial bank; AfDB = African Development Bank; AIIF = African Infrastructure Investment Fund; BWSC = Danish engineering company now owned by Mitsui; CDC = Commonwealth Development Corporation; DEG = German Investment and Development Corporation; DFI = development finance institution; DN = direct negotiation; EAIF = Emerging Africa Infrastructure Fund; EIB = European Investment Bank; EKF = Eksport Kredit Fonden (Danish export credit agency); FMO = Netherlands Development Finance Company; GETFiT = global energy transfer feed-in tariff; ICB = international competitive bid; IDA = International Development Association; IFC = International Finance Corporation; IFU = Danish Investment Fund for Developing Countries; IPS = Industrial Promotion Services; IPS-AKFED = Industrial Promotion Services Aga Khan Fund for Economic Development; IPTL = Independent Power Tanzania Ltd.; KfW = Kreditanstalt für Wiederaufbau; KP&P = company registered in the Netherlands to develop the Lake Turkana Wind Project; KPLC = Kenya Power and Lighting Company; OPEC = Organization of the Petroleum Exporting Countries; OPIC = Overseas Private Investment Corporation; REFiT = renewable energy feed-in tariff; RMB = Rand Merchant Bank; TANESCO = Tanzania Electric Supply Company; YFP = Yinka Folawiyo Power.
a. Shareholders—particularly those with technical expertise—are often prohibited (by lenders) from selling until after commercial operation.
b. The balance of four Ugandan IPPs (Kilembe Mines aka Mubuku I, Kakira, Kinyara, and Kasese Cobalt aka Mubuku III) not included in the table were developed to source electricity to the mining/sugar industries and have evacuated excess power to the national grid. Also not included are the eight GETFiTs and two solar ICBs for which financial close was imminent but not yet complete as of 3Q2015.

government of Uganda (Bujagali), as well as the Kenya Power Pension Fund (Iberafrica)—private sponsors are prominent. Private African partners are present in numerous projects and recently have even taken majority or full equity, as in the case of Aba Integrated (Nigeria), Gulf and Triumph (Kenya), and Tororo and Buseruka (Uganda). Following this, the most conspicuous equity sponsor, Globeleq, hails from Europe, and there are 15 other European entities, such as Aldwych and Wartsila, as well as numerous European bilateral DFIs, such as the Norwegian Investment Fund for Developing Countries (Norfund), the Netherlands Development Finance Company (FMO), and the Danish Investment Fund for Developing Countries (IFU). North American sponsors (primarily from the United States) are significantly fewer, at only seven, followed by South Asia (one), Southeast Asia (one), and the Middle East (one). Equity is also held by multilateral agencies, namely, the International Finance Corporation (IFC) and new infrastructure funds: for example, the African Infrastructure Investment Fund (AIIF) managed by a South African life insurer.

The Role of Development Finance Institutions

In addition to equity investments, DFIs are prominent in the debt financing of IPPs. Their presence has not waned and, arguably, is as integral now as it was 20 years ago—if not more. The sample in table 4.2 indicates a minimum of 42 debt holders on the part of multilateral and bilateral funding agencies for the 26 projects specified in the case study countries. FMO and the IFC are among the most prominent, joined by the African Development Bank (AfDB), the German Investment and Development Corporation (DEG), the European Investment Bank (EIB), the Overseas Private Investment Corporation (OPIC), and Proparco.

One may argue that DFIs possibly crowd out private investment. Indeed, earlier IPPs were predominantly financed by DFIs rather than commercial banks. However, the African reality is one where most IPPs carry substantial risks. Without DFI financing, key projects would not have reached financial close and commercial operation. Nonetheless, African commercial banks are not to be discounted; they took on notable debt in Kenya, Nigeria, South Africa, and Uganda. And recent IPPs, such as Lake Turkana and the Azura IPP, have involved positive cooperation between DFIs and commercial banks. DFIs have also reduced the chances of investments and contracts unraveling—in part because of rigorous due diligence practices, but also because of the pressure governments or multilateral institutions might bring to bear around honoring investment contracts. Only eight of the projects listed in table 4.2 have seen substantial contract changes (that is, the parameters of the original deal were renegotiated after the PPA was signed). Such changes vary, from a scaling back of the original project size (Nigeria's AES Barge) to a reduction in capacity charges (Independent Power Tanzania Ltd. [IPTL], AES Barge, OrPower, Iberafrica, Songas[1]) to a reconfiguration of the project in its entirety (Mtwara and Symbion[2]). Further changes have included the rolling back or elimination of certain security arrangements (for example, Songas's escrow fund) to reduce the financial liability of the state-owned utility. It should be noted that changes occurred in what might be termed the first wave of IPPs in Sub-Saharan Africa—which might signal that there has been a learning process of sorts.

DFIs also contribute to the long-term sustainability of IPP investments, by offering guarantees and insurance (described in the next section). It is of interest that the majority (some two-thirds) of World Bank Group (WBG) guarantees have been provided to projects that were competitively bid. The relative pros and cons of international competitive tenders versus unsolicited bids are discussed in the last section of this chapter.

Risk and Ways to Mitigate It

Owing to the difficult investment environment typical of Sub-Saharan African countries, a key requirement to attract private investment to the power sector is the availability of risk mitigation instruments. Most Sub-Saharan African countries are either unrated or have a credit rating below investment grade; their track record of implementing projects with private sector investors is limited or nonexistent, and their power sectors are in most cases evolving (that is, at an early stage of development or undergoing a reform process). From the perspective of private investors and financiers, these circumstances create uncertainty regarding the future stability of any investment. Such uncertainty translates into high-risk perceptions and high costs of financing—or an inability to raise financing altogether.

The following section explores the types of risks that can affect IPPs, especially in Sub-Saharan Africa, and the menu of risk mitigation measures and their effectiveness.

Risks Associated with Investments in Independent Power Projects

Some types of risk are customary for IPPs, regardless of location, such as contractual risk, construction risk, natural *force majeure*, and so on. These are covered or mitigated through structural arrangements typical of project financing (for example, reserve accounts, liquidated damages) or through comprehensive commercial insurance packages appropriate for the industry.

When investing in Africa, IPPs are faced with an additional set of risks that must be mitigated to make the investment sufficiently attractive or, in some instances, viable. These risks can be classified in the following categories:

- *Political risk* refers to events resulting from adverse actions by the host government (for example, expropriation, repudiation of contract, arbitrary cancellation of permits or licenses, restrictions on the conversion and/or transfer of currencies, and so on) or from politically motivated violence (war, civil strife, coups, terrorism) that can disrupt the construction or the operation of a project, whether temporarily or permanently.

- *Regulatory risk* refers to any change in law or regulation that may have a negative impact on a project, including changes that apply specifically to a project (for example, a change in the tariff agreed by contract) or to the sector in general (for example, structural policy changes). Regulatory risk is perceived as particularly high in countries where the regulatory framework is still evolving, and where there are relatively few precedents for how the legal system handles conflicts resulting from changes in laws.

- C*redit/payment risk* refers to the credit quality and the payment capacity of the off-taker. From an investor's perspective, the profitability of a project hangs upon the ability to collect revenues from the off-taker. As previously alluded to, the low creditworthiness of off-takers is the key challenge to IPP investments in Sub-Saharan Africa. Here, the typical utility's limited financial capacity, substantial financial obligation, and fairly limited commercial flexibility (a limited customer base and highly regulated activities) all pose credit/payment risks that can make or break a project.

Mitigating these risks is therefore critical to make a project bankable and to guarantee fair and sustained returns to investors once the project is under implementation.

A Menu of Risk Mitigation Measures

There are various measures that can be taken to mitigate the risks. Each country's context poses different challenges—as revealed by assessing the experience of previous IPPs—and requires well-tailored solutions. A review of various measures is presented below.

International Arbitration

In the case of large-size projects where the public sector plays a counterpart role, private investors routinely require international arbitration to resolve disputes. In particular, clauses regarding arbitration in instances of a "change in law" or in sector regulations are commonly embedded into PPAs.

Involvement of Development Finance Institutions

When considering an investment in a new country, private sector investors often reach out to the DFI community to seek financing and other types of support for IPPs. This is because, as discussed earlier in this chapter, the DFIs' beneficial role spans well beyond providing financing. Their involvement serves to mitigate risk, especially political risk. DFIs can dissuade governments from making ill-considered changes and point out the potential consequences and spillover effects of the withdrawal of development assistance and finance, especially on the part of large multilateral agencies.

The degree of DFI involvement varies across countries and regions. Some DFIs such as the IFC and AfDB are present basically everywhere in Sub-Saharan Africa. Others are focused in particular regions (such as the West African Development Bank and the Islamic Development Bank in West Africa) or in countries with whom they have traditionally close ties (such as Proparco in francophone Africa).

Sovereign Guarantees

Sovereign guarantees are the most common instrument to mitigate off-taker risks where off-takers are not creditworthy or not perceived as such. This is the case when their financial standing is weak or they rely heavily on government subsidies, or in contexts where there is no long or solid track record of private sector investment in the power sector. In these circumstances, the private sector may ask the government to back the off-taker's obligations under the PPA. As countries build a track record of successful IPPs, they can slowly reduce the issuance of these guarantees or limit them only to cover specific risks (as opposed to covering the full PPA).

Structural Measures

Structural measures can be designed to ring-fence revenues accruing to off-taker utilities and ensure that there is enough cash flow to honor payment obligations under the PPA. In Côte d'Ivoire, for example, a sectorwide mechanism has been put in place to collect all power sector revenues, which are then allocated on a priority basis to cover IPP payments. This measure has worked very well in the country and has allowed it to successfully develop some of the largest IPPs in Sub-Saharan Africa (Azito and CIPREL).

A similar, smaller-scale option consists of transferring the bill collection for a set of large customers from the utility to an escrow account managed by the IPP. These "delegated customers" typically represent a profitable customer segment, ensuring a stable stream of revenues to the utility. The problem with this arrangement is the lack of replicability: once the best customers are delegated to the first IPP, it becomes difficult to identify enough customers suitable for delegation to any IPPs that follow. A sectorwide cash flow channel, meanwhile, is an arrangement that can accommodate future projects.

Although host governments can provide sovereign guarantees or arrange any of the risk mitigation measures presented earlier, their financial capability to deliver on IPP commitments may remain in doubt, or the legal underpinning of such commitments may be uncertain. In this context, equity investors and financiers must put in place further risk mitigation instruments that transfer risks to third parties. The most commonly used instruments are (1) multilateral development bank (MDB) guarantees and (2) insurance products, in particular political risk insurance (PRI).

While most MDBs offer guarantees, the guarantees provided by the World Bank—specifically the International Bank for Reconstruction and Development (IBRD) and the International Development Association (IDA)—have been the most widely used in the Sub-Saharan African region.

World Bank Guarantees

World Bank guarantees are designed to provide credit enhancement and direct risk mitigation. They are flexible in nature and adaptable to the specific requirements of each project and to market circumstances. Customarily, the World Bank guarantees are issued for the benefit of private investors (project companies or lenders) to guarantee timely payment of obligations due by government-owned entities under key project contracts, such as payments due under PPAs signed by government-owned utilities with privately owned project companies. World Bank guarantees are of two main types: (1) project based and (2) policy based. Project-based guarantees are applied in the context of specific investment projects where governments wish to attract equity and/or debt by the private sector. They are the instruments best suited and typically used to support IPPs in Sub-Saharan Africa.

Project-based guarantees (formerly called partial risk guarantees, PRGs) include the following subcategories:

- *Loan guarantees* mitigate the risks faced by commercial lenders with respect to debt service payment defaults caused directly or indirectly by a government

failure to meet specific payment and/or performance obligations arising from contracts, laws, or regulations. Debt service payment defaults may relate to:
  - Commercial loans taken by private projects, which rely on contracts with the government for their cash flows and may be affected by certain factors such as a change in tariff levels named in an implementation agreement between the government and a project.
  - Commercial loans taken directly by the government.
- *Payment guarantees* are intended to mitigate the risk faced by private projects or foreign public entities with respect to payment default on government obligations not related to loans. Such obligations include scheduled or unscheduled predetermined payments arising from contracts, laws, or regulations (for example, monthly payments under a PPA); and termination payments due under a government support agreement (GSA) as a result of a change in law.

A notable and recent example of the suite of risk mitigation instruments offered by the World Bank is provided by the Azura project in Nigeria (see box 4.1).

Box 4.1 Mitigating the Risk of an Independent Power Project: The Case of Azura, Nigeria

Azura, which reached financial close in 2015 after considerable delays, has been a path-breaking independent power project (IPP) in Nigeria: it is the first project-financed power generation project to have been developed since that country's power sector reforms began. Investment costs—at $895 million for a 450 megawatt (MW) open-cycle gas turbine (OCGT)—are high and reflect perceptions of risk. The counterparty of the power purchase agreement (PPA) is a newly created Nigerian Bulk Electricity Trading (NBET), with insufficient liquidity and dependent on revenue flows from newly privatized distribution companies that are still experiencing high losses and insufficient collections. Development costs have been high. Each contract has had to be negotiated from scratch. Because Azura was the first IPP to be established in Nigeria for several years, there were no ready-made templates for it to follow, and capacity had to be built among the various stakeholders. The project sponsor is a relatively small, cash-poor, first-generation developer that had to leverage equity partners and a large number of debt providers, each of which wanted to limit its exposure. The International Finance Corporation (IFC) was a colead arranger of the development finance institution (DFI) component of the debt, and the World Bank employed its full range of risk mitigation instruments to make the project bankable.

The Multilateral Investment Guarantee Agency (MIGA) provided a full equity guarantee as well as a partial risk debt guarantee. The International Bank for Reconstruction and Development (IBRD) provided for project-based guarantees (formerly partial risk guarantees, PRGs), including both payment and loan guarantees. (The payment guarantee backstops

box continues next page

Box 4.1 Mitigating the Risk of an Independent Power Project: The Case of Azura, Nigeria *(continued)*

payment obligations by the NBET.) Specifically, the guarantee ensures security under the PPA in the form of a letter of credit (LC) issued by a commercial bank in favor of the IPP. The LC can be drawn in the event the NBET or the government of Nigeria fails to make timely payments to the IPP. Following the drawing up of the LC, the NBET would be obligated to make a repayment to the LC bank (under the reimbursement and credit agreement), failing which the LC bank would have recourse to the IBRD PRG under the guarantee agreement, which in turn would trigger the obligation of the federal government of Nigeria under the indemnity agreement.

The loan guarantee provides direct support to commercial lenders in the event of a debt payment default caused by the NBET's failure to make undisputed payments under the PPA, or the government of Nigeria under a termination of the PPA. There is also an LC for gas supply.

Given the complexity and cost of the Azura deal, questions have been asked as to whether project-financed IPPs are worthwhile in risky environments. The counterargument is that Azura has shown the way and that subsequent IPPs will be much easier. In a sense, the development and risk mitigation costs of Azura could be seen to be spread across a large pool of IPPs currently under development. More important, as the power market evolves and more private investments flow into it, future IPPs are expected to be less costly to develop and to require less risk mitigation.

Source: Compiled by the authors, based on various primary and secondary source data.

African Development Bank Guarantees

The AfDB also offers guarantee instruments. These were introduced in 2004 for middle-income countries, and later (in 2011) extended to low-income countries. AfDB guarantees are of two kinds: (1) partial credit guarantees (PCGs) and (2) partial risk guarantees (PRGs).

PCGs cover a portion of scheduled repayments of private loans or bonds against all risks. Their application spans project finance (including IPPs), financial intermediation, and policy-based finance. Specifically, project finance PCGs are normally used to help extend loan/bond maturity and ease access to capital markets for public and private investments alike. They can be applied to cover the principle for the bullet maturity of corporate bonds, or, later, the maturity principle payments of amortizing syndicated loans.

PRGs insulate private lenders against well-defined political risks related to the failure of a government or a government-related entity to honor specified commitments. Such risks could include political force majeure, currency inconvertibility, regulatory risks (adverse changes in law), and various forms of breach of contract.

Insurance Products

Insurance products may be provided by multilateral and bilateral agencies, export credit agencies, or private insurers. The providers most common in

Sub-Saharan Africa are the Multilateral Investment Guarantee Agency (MIGA), the OPIC, and the African Trade Insurance Agency (ATI). Political risk insurance (PRI) typically provides insurance to private equity investors and/or to lenders against traditional political risks (as specified in the coverage), resulting in a default by a sovereign or a corporate entity to honor its obligations.

Guarantees and insurance are complementary products. As such, it is not uncommon for a project to benefit from both instruments, a practice that is favored in large and complex projects.

The Impact of Risk Mitigation

How does risk mitigation intersect with projects' bankability and sustainability? To what extent have the instruments described been effective in attracting lenders? And to what degree have such mechanisms helped keep projects intact or led to a swift resolution, in the face of external pressures?

The Sub-Saharan African experience clearly points to the fact that risk mitigation has been critical in attracting private investments to strategic IPPs located in challenging markets. A few notable examples follow.

Kribi Gas Power Project, Cameroon

Developed by the Kribi Power Development Company (KPDC), this project consists of a new 216 megawatt (MW) natural-gas-fired power plant and an associated 100-kilometer (km) transmission line. The total project cost was $350 million, financed with a 75:25 debt-to-equity ratio. One of the major challenges was to secure long-term loans in the local currency. Until 2011, most of the infrastructure financing in Cameroon was done on a corporate basis through equity and foreign-currency-denominated loans from DFIs. The only exception was the Dibamba thermal power plant, which was financed on a project finance basis with private equity and loans from DFIs denominated in foreign currency. Local and international commercial banks provided only short-term corporate financing.

The government of Cameroon wanted local banks to participate in the financing of Kribi. Its objective was twofold: (1) to introduce a local-currency component into the financing package to mitigate foreign-exchange risk (which is passed through to the tariff), and (2) to develop the capacity of the local lending market in long-term project finance.

While local lenders had liquidity and strong interest in participating in the financing of private projects, they suffered from structural and regulatory constraints that limited maximum maturities of the loan to seven years—insufficient for long-term infrastructure financing needs. Moreover, the fact that the government and associated entities lacked a track record in private project financing left local lenders with a high degree of uncertainty (that is, perceived risk). Thus, the challenge was to create a financial structure that might attract local lenders with relatively little experience in project finance, and overcome the regulatory restrictions on the tenor of local lending.

As a response to these constraints, the government, local banks, and the IDA joined efforts to design a local loan with an innovative structure. The seven-year maturity constraint was turned into a 14-year amortization profile through a "put option" in favor of the local lenders under which, at the end of seven years, local lenders might exercise the option and sell their participation to the government at a price defined in the local loan purchase agreement. In this case, the government would hold the local loan until the KPDC or the government itself found new commercial lenders to take it up. If local lenders did not exercise their put option, the loan would be extended for a second seven-year term. The government's obligation to purchase it was secured by an $82 million World Bank guarantee.

Kribi's financing structure provided a novel way of addressing problems common to large infrastructure projects in low-income countries: currency mismatch, short loan tenor, regulatory constraints, and government creditworthiness. The World Bank's involvement enabled Cameroon's first long-term, local-currency loan for infrastructure and thus contributed to building capacity within local banks and bolstering the development of both the financial and infrastructure sectors. In addition, the local component of the financing package reduced foreign-exchange risks.

Recent Thermal Independent Power Projects, Kenya

In 2011, three IPPs—namely, Thika Power Ltd. (87 MW), Triumph Power Ltd. (82 MW), and Gulf Power Ltd. (80 MW)—were identified as strategic to meeting Kenya's urgent power generation needs. The Kenya Power and Lighting Company (KPLC), Kenya's government-owned utility, selected private sponsors through a competitive tender process and signed 20-year PPAs with each of the three IPPs. However, these projects were tendered at a time when financial markets were still suffering the impact of the 2008 global financial crisis and project financiers remained risk averse. Moreover, the financial situation of the KPLC started deteriorating, driven in part by an ambitious network expansion plan. To make things worse, Kenya's political stability was perceived as fragile after the civil unrest that followed the 2007 presidential elections, and there were concerns over the upcoming 2013 presidential elections.

During the project tender process, it became clear to the KPLC that it would not be able to attract investors unless it offered significant credit enhancement such as sovereign guarantees. The government of Kenya, however, was constrained in its ability to provide sovereign guarantees due to its limited fiscal space and a tight debt ceiling agreed on with the International Monetary Fund (IMF). The KPLC, in turn, found it difficult to continue offering the security packages that it had provided under the PPAs with previous IPPs. Those security packages had become financially onerous as they required full cash collateral, thus impacting the KPLC's ability to direct resources for its operating needs and its investment program.

As a response, the Kenyan government, the KPLC, and the World Bank opted for exploring credit-enhancement options that might encourage the required private financing, while minimizing the contingent liabilities for the government and the financial cost for the KPLC. After a market-sounding exercise, a credit-enhancement package consisting of IDA guarantees (to backstop ongoing payment obligations of the KPLC under the PPAs) and MIGA insurance (to cover termination payments) was put together for these projects. In addition, the IFC provided support through long-term debt financing for two of the IPPs.

The IDA guarantees were structured around two goals. First, to ensure timely payments of energy, capacity, and fuel charges and assure investors that the projects' cash flow would be protected against any payment default by the KPLC or government interference. Second, to ensure that in the event of a KPLC payment default, remedial actions would be taken during a 12-month period so that the liquidity protection could be reinstated and remain in place for 15 years, which was the tenor of the underlying financing.

Both goals were accomplished with the use of standby letters of credit (SBLCs) backstopped by IDA guarantees. Commercial banks issued the SBLCs to project companies on behalf of the KPLC as a payment security for ongoing KPLC payment obligations under the PPAs. The SBLCs allowed project companies to withdraw funds in the event that the KPLC failed to make a timely payment under the PPAs. In that case, the KPLC or the government was obliged to repay to the SBLC bank the amount drawn within 12 months. If it failed to do so, the World Bank would pay under the IDA guarantee.

The MIGA provided insurance to equity investors and commercial lenders to cover the termination payment obligations of the KPLC (as a result of a breach of contract, as stipulated under the PPA) and the government (as a result of breach of contract, under the government letter of support). The MIGA insurance also covered transfer restrictions.

The WBG's support ensured the mobilization of private financing for needed additional generation capacity that otherwise would not have been achieved. The crucial value of the IDA guarantee was to enable the bankability of the IPPs. All three IPPs attracted long-term commercial financing, becoming the first projects to do so in Kenya. The IFC and other DFIs played a critical role in providing debt financing. These IPPs have become benchmarks for long-term financing in Kenya—and Africa.

Tobene Power Project, Senegal

This is a 96 MW power plant developed by Tobene Power SA, whose main shareholder is the Matelec Group of Lebanon. The total project cost was €127 million, financed on a 75:25 debt-to-equity basis. Tobene is currently under construction; once completed it will deliver power to SENELEC, the national utility and single off-taker, under a 20-year PPA.

As a reaction to the nation's power crisis, in 2010 the government of Senegal carried out a sector diagnostic that highlighted an increasing gap between fast-growing demand and insufficient, costly, and unreliable supply of electricity. The diagnostic also underscored SENELEC's persistent financial difficulties, characterized by a significant operating deficit and high indebtedness. In response, the government developed a 2011–15 electricity emergency plan, outlining an overall policy framework and strategy to put the sector on a more sustainable footing and build SENELEC's financial and operational sustainability over the long run. The Tobene Power Project was identified as a key IPP under the plan.

Although Senegal was among the first countries in Sub-Saharan Africa to introduce private participation in the power sector, in the late 1990s, the track record of its IPPs was mixed. This is mainly a consequence of SENELEC's poor payment track record, as well as a number of technical issues that reduced electricity output from these plants, including the variable quality of fuel delivered by SAR (a state-owned refinery) and grid instability. Therefore, investors were reluctant to proceed with developing Tobene unless risk mitigation was provided.

As a response, the government of Senegal, together with the World Bank, agreed to offer an IDA guarantee backstopping the payment obligations of SENELEC and the government, under the PPA and under the government guarantee, respectively. The IDA guarantee of $40 million covers ongoing payment obligations as well as a portion of termination payments resulting from a breach of contract by the government or SENELEC. In addition to the IDA guarantee, the project also benefited from long-term debt financing and an equity contribution through the IFC and IFC InfraVentures. The remainder of the debt financing was provided by other DFIs, such as FMO, the Emerging Africa Infrastructure Fund (EAIF), and the West African Development Bank (BOAD).

The IDA guarantee was considered key to attracting private capital for Tobene as well as long-term debt financing, which would have not been available otherwise. Commissioning of Tobene is expected in 2016. Once in place, the project will make a critical contribution to reducing power shortages and diversifying the energy mix away from expensive emergency diesel generation. It is also a hallmark of the government's interest in increasing private sector participation.

Going forward, risk mitigation promises to remain critical in attracting private financing to projects. The question of off-takers' creditworthiness alone offers justification for resorting to security arrangements and credit enhancements, whether the risk is real or only perceived by prospective investors. For instance, in Kenya, despite the sheer number of IPPs and the proven track record of payment via the KPLC, investors still claim that the KPLC "is not an investment grade company" (Aldwych International, personal communication with authors, 2010). Contrast this situation with that of other middle-income countries, such as those in Latin America, where the PRG and other credit enhancements and security arrangements are virtually absent. There, power markets are in operation, including long-term bilateral contracts, and local lenders are generally comfortable with local developers and regulation.

Nevertheless, as IPP markets mature in Sub-Saharan Africa, it is possible that the use of risk mitigation arrangements will diminish. In Nigeria, for example, the IPPs that follow Azura are unlikely to utilize as wide an array of credit-enhancement instruments.

As risks are reduced, greater private investment should be encouraged, and DFIs should focus on projects that commercial banks cannot finance.

Finally, it is important to note that in no projects have guarantees of any sort been invoked, including in those projects whose contracts ultimately unraveled (namely, AES Barge, IPTL, OrPower4, or Takoradi II). Recourse to international arbitration has been made only in the case of IPTL in Tanzania, where it shaved $30 million off the investment cost.

Technology Options: A Rise in Independent Power Projects Using Solar and Wind Energy

The past decade has witnessed a revolution in renewable energy technologies such as wind and solar energy. They have grown especially in the past five years, with costs falling and efficiencies improving remarkably. The levelized cost of onshore wind per megawatt-hour has now reached a level that is competitive with combined-cycle gas turbine (CCGT) and coal-fired generation, without taking into account the environmental and social costs of carbon. While not yet as competitive as wind, solar photovoltaic (PV) has seen among the greatest cost reductions. Geothermal energy has also proved to be cost competitive. Renewable power capacity, excluding large hydropower, represented 44 percent of all new global capacity in 2013, amounting to $192 billion in investment (FS-UNEP 2014).

A similar trend has not, however, been observed in fuel-to-power plants, although there are notable developments in the gas sector, with implications for natural-gas-fired plants. This has serious ramifications for power development in Sub-Saharan Africa and particularly for IPPs: with falling costs, grid-connected renewable energy (particularly solar and wind) is gaining traction and represents significant new investment.

Wind and Solar Energy Price Trends in Sub-Saharan Africa

How do wind and solar energy IPPs score in the five case study countries and, by contrast, how do fuel-to-power IPPs measure up in terms of actual price outcomes?[3]

The most dramatic outcomes of wind and solar energy IPPs have been in South Africa's Renewable Energy Independent Power Project Procurement Programme (REIPPPP), discussed in more detail later in this chapter, where between 2012 and 2015, 92 new projects were contracted, amounting to 6,327 MW of capacity (including small quantities of hydropower, biomass, and biogas) and more than $19 billion in private investment, with impressive price outcomes. Grid-connected wind and solar renewable energy in South Africa is now among the cheapest in the world: solar PV prices are as low as U.S. cents (USc) 6.4/kilowatt-hour (kWh) and wind as low as USc 4.7/kWh.[4] These outcomes will not, however, be easy to replicate in other African countries, which have smaller markets with less competition; more risky investment climates; thinner domestic capital markets; and less-experienced local financial, legal, and advisory service industries.

Two solar projects have been developed in Uganda under the global energy transfer feed-in tariff (GETFiT) program (presented in detail later in this chapter) with less impressive results (USc 16.4/kWh), due to a much smaller market size, less competition, and more broadly, a higher-risk environment. Nonetheless, the technology is gaining ground and is still cheaper than the imported fuel-to-power alternative in Uganda. The directly negotiated solar PV deals in Rwanda and Nigeria—at over USc 20/kWh—are more expensive than the competitively bid projects.

Outside South Africa, the wind story has been focused on Kenya: first in its directly negotiated Lake Turkana 300 MW project, and then in the more recent renewable energy feed-in tariff (REFiT)–procured Kinangop IPP (60 MW), at USc 10.39/kWh[5] and USc 12/kWh,[6] respectively, which are marginally more expensive than Kenya's private geothermal capacity but outdo any of the country's existing thermal plants, as previously noted. IPP wind developments have also taken shape in Cabo Verde, through a 25 MW installation that has helped offset high-price thermal imports.

Outcomes of other renewable energy IPPs are presented in box 4.2.

Sub-Saharan African Experience with Feed-in Tariffs

As frontier technologies, solar and wind-based generation entails higher up-front costs and different risk profiles than traditional, and especially thermal, technologies. Countries interested in these and other renewables have experimented with methods to incentivize private investment in them. Until recently, the most widely adopted procurement strategy for attracting renewable energy IPPs involved feed-in tariffs (FiTs) (at least in terms of policy and regulations). Six Sub-Saharan African countries have FiTs for small hydropower, solar, wind, geothermal, and biomass/waste (table 4.3).

FiTs have primarily been promoted by European bilateral aid programs, premised on the assumption that renewable energy costs are higher than those of other options, and renewable energy projects need premiums to attract investment (Davies and Allen 2014). Meanwhile, FiTs are beginning to face criticism in their markets of origin because prices have not come down as fast as competitive tenders.

In Africa, the experience with this instrument has been disappointing, and relatively few projects have materialized. In Kenya, specific interventions to accelerate renewables with a FiT policy date to 2008. The first iteration of this policy did not attract investors, and tariffs were subsequently reviewed in January 2010 and decreased (BNEF and others 2014). In Uganda, FiTs have been retooled and have finally taken off under the GETFiT program, as described below. The two-year South African experiment with FiTs, which was terminated with no contracts signed, is highlighted in box 4.3.

Uganda GETFiT Tender Design

REFiTs in Uganda did not manage to attract any renewable energy investments before 2013. In 2013, the Kreditanstalt für Wiederaufbau (KfW, German

Box 4.2 Independent Power Projects Using Hydropower, Geothermal, and Biomass

Large hydropower independent power projects (IPPs) have emerged, albeit only in the form of Bujagali in Uganda (250 megawatts, MW) and, more recently, Itezhi in Zambia (120 MW). Bujagali, at U.S. cents (USc) 10/kilowatt-hour (kWh), has helped offset higher-price thermal installations (USc 24–27/kWh), and contributed 45 percent of total generation in 2013. This technology is now largely being developed in the form of publicly owned projects with Chinese-backed funding, and with Chinese engineering, procurement, and construction (EPC), which have distinguished themselves as market leaders worldwide. This follows global trends: 14 of the 19 projects with the greatest hydropower capacity worldwide are wholly state owned (FS-UNEP 2014: 41).

In contrast, **small hydropower IPPs (<20 MW)** have seen an upsurge in activity, particularly in Uganda. Each of the small hydropower IPPs (at around USc 9/kWh) are superior price-wise to the thermal alternative (heavy fuel oil, HFO), which relies on imported fuel. Prior to the global energy transfer feed-in tariff (GETFiT) program, Uganda had procured six small hydropower IPPs; GETFiT, with an initially anticipated close of more projects in 2015, pushes that tally closer to 14.

On the **geothermal** front, private investments in Kenya date to 1999, when OrPower won the first tender. At USc 9/kWh, the IPP geothermal plant is slightly more expensive than state-run geothermal plants (USc 7/kWh) and superior to all fuel-to-power alternatives available in the country (in the range of USc 20–33/kWh). Geothermal is expanding rapidly in Kenya, both via public and private procurement.

Biomass IPPs are well established in Mauritius, which has a fleet of bagasse cogeneration plants that collectively account for 110 MW of installed capacity, dating from 1997. South Africa, Kenya, Uganda, and, most recently, Angola, have also added bagasse to their electric power supply; Kenya's Mumias IPP plant, at USc 5/kWh, is more competitive than geothermal and is outcompeting any fuel-to-power alternative, as noted.

Source: Compiled by the authors, based on various primary and secondary source data.

development bank) assisted the Uganda regulator, the Electricity Regulatory Authority (ERA), in developing the GETFiT to incentivize new investments that might plug the difference between supply and demand before two large new hydropower projects, Isimba and Karuma, came online.

The primary GETFiT mechanism is a grant-based premium payment at the REFiT levels to close the gap with the levelized cost of energy (LCOE) for eligible technologies, namely small hydropower, biomass, bagasse, and solar PV. The per-kilowatt-hour-based GETFiT subsidy is calculated over the 20-year lifetime of the PPA, but is designed as a performance-based payment to the developer over the first five years of operation to enhance the project's debt service profile.

An important and valuable part of the program has been the development of a full set of legal documents including standardized (and investor-approved)

Table 4.3 Sub-Saharan African Countries with Feed-in Tariffs, Grid-Connected, as of 2014
USc/kilowatt-hour

Country	*Small hydro FiT*	*Solar FiT*	*Wind FiT*	*Geothermal FiT*	*Biomass FiT*	*Biogas FiT*
Ghana	17.74[a]	21.21[b]	18.35[c]	—	—	10.36
Kenya	8.25	12	11	8.8	10	10
Nigeria	17.33[d]	49.92	18.07	—	20.19	—
Rwanda	6.7–16.6	—	—	—	—	—
South Africa (2011)	8.4	29	11.8	—	13.3	10.5
Uganda	8.5[e]	11	12.4	7.7	10.3	11.5

Sources: Based on BNEF and others 2014; NERSA 2011. South African FiTs are no longer applicable.
Note: FiT = feed-in tariff; kWh = kilowatt-hour; MYTO-2 = Multi-Year Tariff Order 2; USc = U.S. cent; — = not available.
a. Ghanaian small hydropower, assuming average 2014 exchange rate of $1= Ghanaian cedi 3.0367. All tariff rates are as of October 1, 2014 (BNEF and others 2014).
b. Ghanaian solar photovoltaic (PV) with grid stability; solar PV without grid stability is USc 19.21 (BNEF and others 2014).
c. With grid stability system; wind without grid stability indicated at USc 16.93 (BNEF and others 2014).
d. Based on MYTO-2 2014 FiT prices.
e. Maximum tariffs available at auctions for hydro, bagasse (USc 9.5/kWh), biomass, biogas, geothermal, landfill (USc 8.9/kWh), and wind (solar is under a separate regime).

Box 4.3 The South African Experiment with Renewable Energy Feed-in Tariffs

In South Africa, a renewable energy feed-in tariff (REFiT) policy was approved in 2009 by the National Energy Regulator of South Africa (NERSA). Tariffs were designed to cover generation costs plus a real after-tax return on equity of 17 percent, to be fully indexed for inflation (NERSA 2009). Initial published feed-in tariffs (FiTs) were generally regarded as generous by developers—U.S. cents (USc) 15.6 per kilowatt-hour (kWh) for wind, USc 26/kWh for concentrated solar power (CSP, troughs with 6 hours' storage), and USc 49/kWh for photovoltaic (PV).[a] But the procurement and licensing process remained uncertain. The legality of FiTs within South Africa's public procurement framework was unclear, as was Eskom's (the national electricity utility) intention to fully support the REFiT program by allowing the timely finalization of power purchase agreements (PPAs) and interconnection agreements.

In March 2011, the NERSA introduced a new level of uncertainty with a surprise release of a consultation paper calling for lower FiTs, arguing that a number of parameters—such as exchange rates and the cost of debt—had changed. The new tariffs were 25 percent lower for wind, 13 percent lower for CSP, and 41 percent lower for PV. Moreover, the capital component of the tariffs would no longer be fully indexed for inflation. Importantly, in its revised financial assumptions, the NERSA did not change the required real return for equity investors, set at 17 percent (NERSA 2011).

More policy and regulatory uncertainty was to come. Already concerned that the NERSA's FiTs were still too high, the Department of Energy (DoE) and National Treasury commissioned a legal opinion that concluded that FiTs amounted to noncompetitive procurement and were therefore prohibited by the government's public finance and procurement regulations. The DoE and National Treasury then took the lead in a reconsideration of the government's approach. The fundamental goal of achieving large-scale renewable energy projects with private developers and financiers remained the same. However, the structure of the transactions,

box continues next page

Box 4.3 The South African Experiment with Renewable Energy Feed-in Tariffs *(continued)*

including the FiTs, was to change significantly. A series of informal consultations were held with developers, lawyers, and financial institutions throughout the first half of 2011. These meetings proved to be extremely important in allaying market concerns resulting from the earlier REFiT process and providing informal feedback from the private sector on design, legal, and technology issues.

In August 2011, the DoE announced that a competitive bidding process for renewable energy would be launched (the Renewable Energy Independent Power Project Procurement Programme, REIPPPP). Subsequently, the NERSA officially terminated the REFiTs. Not a single megawatt of power had been signed in the two years since the launch of the REFiT program; a practical procurement process was never implemented, and the required contracts were never negotiated or signed. The abandonment of FiTs, meanwhile, was met with dismay by a number of renewable energy project developers that had secured sites and initiated resource measurements and environmental impact assessments. But, it was these early developers who would later benefit from the first round of competitive bidding under the REIPPPP.

Source: Compiled by the authors, based on various primary and secondary source data.
a. These values are calculated at the exchange rate of the time, R (rand) 8 = $1.

PPAs, implementation agreements, and direct agreements (securing lender takeover rights). World Bank PRGs are available to successful projects to address off-taker and termination risks. Support is also provided for lender due diligence. Furthermore, GETFiT assists the government of Uganda in further streamlining essential procedures for project implementation, such as the permit and licensing process as well as the operationalization of tax and custom exemptions provided to IPPs.

Three competitive tenders were run for small hydropower and biomass (1–20 MW), based on the quality rather than the price of projects. Projects had to meet minimum qualitative benchmarks (table 4.4). Prices were determined by the REFiT plus the premium payment. Project developers proposed their own sites and had to undertake full feasibility and interconnection studies; they had to secure permits and prepare environmental and social impact assessments (ESIAs) in compliance with the IFC's performance standards, including a Resettlement Action Plan (RAP), wherever applicable. An additional competitive tender was run for solar PV projects with a maximum size of 5 MW.

The GETFiT facility also funded a secretariat, supported by an implementation consultant, which ran the tenders and assessed bids, with ultimate approval from an investment committee. By early 2015, GETFiT had confirmed support for a total of 15 projects with an accumulated 128 MW capacity. Forty-one applications were received over three bid rounds.[7] In January 2015, the third and last request for proposals under the "classic" GETFiT setup was issued. When the GETFiT Investment Committee was convened for the last time in June 2015, a further six projects were approved. But amid funding constraints,

Table 4.4 Criteria for the Evaluation of Global Energy Transfer Feed-in Tariffs, Uganda

"Classic" GETFiT (small hydro, biomass, bagasse)	*GETFiT solar facility*
Financial and economic performance Minimum FIRR, DSCR, sensitivity DPC, ERR, contribution to energy balance and grid stability	Economic performance ERR Project maturity and location
Environmental and social performance Quality and IFC compliance of ESIA/ESAP Quality and IFC compliance RAP/LRF	Environmental and social performance
Technical and organizational performance Feasibility of proposed site Quality of technical documentation	Technical and organizational performance Quality of technical documentation Project implementation timeline/expected COD
Project implementation timeline Maturity of project and financial package Risk analysis	Price proposed per kilowatt-hour (70% of total score)

Source: Compiled by the authors, based on various primary and secondary source data.
Note: COD = commercial operation date; DPC = dynamic production cost; DSCR = debt service coverage ratio; ERR = economic rate of return; ESAP = environmental and social action plan; ESIA = environmental and social impact assessment; FIRR = financial internal rate of return; GETFiT = global energy transfer feed-in tariff; IFC = International Finance Corporation; LRF = livelihood restoration framework; RAP = Resettlement Action Plan.

just three additional small hydropower projects, totaling 25 MW, were accepted. An additional tender was run for solar PV, which attracted 24 expressions of interest; 9 were short-listed and 7 bids submitted. In the end, two project developers were awarded two 5 MW projects each.

GETFiT was designed as a temporary facility, likely to be phased out. The idea was to stimulate the small-scale renewable energy market, initially through a premium payment but, importantly, also through firming up the contractual framework and providing confidence to investors. It remains to be seen whether further regular competitive tenders will be conducted after the withdrawal of donor support.

Procurement and Contracting Mechanisms

Within the context of procuring IPPs, we define competition as competition *for* the market, that is, competitive tenders or auctions for long-term contracts between new IPPs and off-takers, typically the national or local utility. In contrast, directly negotiated deals are awarded without an open bidding process, and most often originate in unsolicited proposals from interested investors.

The majority of IPPs developed in Africa (80 of the 126 for which data are available) have been competitively procured (table 4.5). But without South Africa (which accounts for 67 projects), the numbers change dramatically: only 16 competitive tenders versus 34 directly negotiated projects. Not only do direct negotiations outnumber competitive tenders across the Sub-Saharan Africa pool, excluding South Africa, but they also represent the majority of the megawatts procured.

Table 4.5 Comparison of Procurement Methods Used for Independent Power Projects, Sub-Saharan Africa

	C	*C*	*C*	*DN*	*DN*	*DN*	*REFiT*[a]	*REFiT*[a]	*REFiT*[a]			
	No. of projects (%)	*US$, millions (%)*	*MW (%)*	*No. of projects (%)*	*US$, millions (%)*	*MW (%)*	*No. of projects (%)*	*US$, millions (%)*	*MW (%)*	*Total number*[b] *(%)*	*Total US$, millions*[b] *(%)*	*Total MW*[b] *(%)*
All IPPs	80 (68%)	17,008.52 (68%)	5,580 (52%)	37 (31%)	7,840.06 (31%)	5,115.3 (48%)	1 (1%)	150 (1%)	60 (1%)	118 (100%)	24,999 (100%)	10,755.3 (100%)
SSA IPP (excl. SA)	16 (31%)	2,997 (28%)	1,665 (26%)	34 (67%)	7,417 (70%)	4,730 (73%)	1 (2%)	150 (1%)	60 (1%)	51 (100%)	10,564 (100%)	6,455 (100%)
SA IPP	64 (96%)	14,012 (97%)	3,915 (91%)	3 (4%)	423 (3%)	385 (9%)	0 (0%)	0 (0%)	0 (0%)	67 (100%)	14,435 (100%)	4,300 (100%)

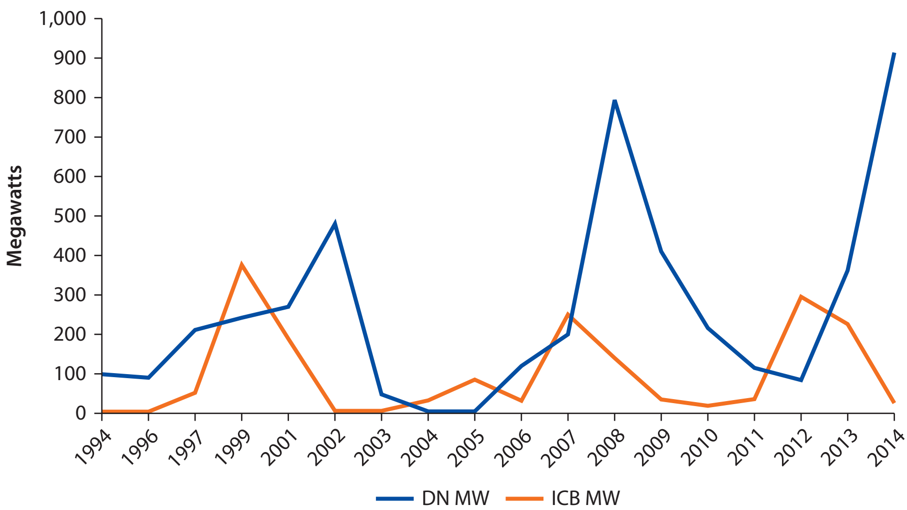
Source: Based on authors' calculations.

Note: C = competitive tender; DN = direct negotiation; IPP = independent power project; MW = megawatt; REFiT = renewable energy feed-in tariff; SA = South Africa; SSA = Sub-Saharan Africa.

a. This refers to the Kinangop greenfield wind project (60 MW) and does not include Uganda REFiTs and solar, which had initially been expected to reach financial close in 2015.

b. This project tally and associated megawatt and investment totals exclude 305 MW from five projects in Mauritius (293 MW), one IPP in The Gambia (25 MW), one IPP in Cabo Verde (25 MW), and one IPP in Madagascar (15 MW), for which procurement information was outstanding in 2015. In terms of methodology, it should be noted that if projects are initially procured via an international competitive bid (ICB), then any expansions (and associated investment and megawatts), unless otherwise specified, are also counted as an ICB, regardless of whether there was additional competition. The same applies to those projects procured via direct negotiation.

Figure 4.1 Competitive Tenders versus Directly Negotiated Projects, Sub-Saharan Africa (Excluding South Africa), 1994–2014



Source: Based on authors' calculations.
Note: No IPPs recorded for 1995 or 2000, which explains the absence of those years in the figure. DN = direct negotiation; ICB = international competitive bid; IPP = independent power project; MW = megawatt.

To what extent have trends moved toward or away from one procurement method? Figure 4.1 shows a cycle that mimics the larger investment cycle, as first highlighted in chapter 2. There is neither a move toward or away from either competitive tenders or directly negotiated projects, but a consistent engagement with both—again excluding South Africa, where ICBs are the dominant procurement method.

Following South Africa, Kenya has had the most success in conducting international competitive tenders, with six such procurements for 11 IPPs (table 4.6). Successful bid processes tend to make subsequent tenders easier and more predictable, which in turn potentially lead to more bids and more competition.

Why Countries Sometimes Pursue Direct Negotiations over Competitive Tenders

Based on the specific experience of the five case study countries, the analysis here investigates circumstances that drive governments to choose directly negotiated IPP contracts rather than competitive selection based on an open bidding process.

Conspicuously, every one of the five study countries procured its first IPP via a direct negotiation. Kenya was the first in 1996, followed by Tanzania in 1997; Uganda and Nigeria would follow in 1999 and 2001, respectively. South Africa came last, in 2005—initially for a mere 7 MW but later for a larger open-cycle gas turbine (OCGT) plant when a competitive tender failed.[8] Uganda had a slower transition to private power, first integrating excess power from multiple captive plants (Mubuku I, III) involved in mining operations.[9]

Table 4.6 Summary of IPP Projects and Procurement Methods in Case Study Countries: Sub-Saharan Africa, 1990–2014

Country	*No. of projects*	*Capacity (MW)*	*Total investment (US$, millions)*
Kenya	11	1,065.5	2,361.4
DN (1996x2, 2008, 2014)	4	480.5	1,133.4
C (1999x2, 2008, 2012, 2013)	6	525.0	1,077.9
REFiT (2013)	1	60.0	150.0
Nigeria	4	1,521.0	1,702.0
DN (2001, 2002, 2008, 2013)	4	1,521.0	1,702.0
South Africa	67	4,307.3	14,434.6
DN (2005, 2006, 2010)	3	385.0	422.6
C (2012, 2013, 2014)	64	3,922.3	14,012.0
Tanzania	4	427.0	598.4
DN (1997, 2006)	2	220.0	250.4
C (2001, 2005)	2	207.0	348.0
Uganda	11	451.3	1,274.4
DN (1975, 1999, 2003, 2008, 2009, 2012)	9	151.3	340.4
C (2007, 2008)	2	300.0	934.0
Grand total	**97**	**7,772.1**	**20,370.8**

Source: Compiled by the authors based on various primary and secondary source data.
Note: Excludes Uganda's REFiT and South Africa's Renewable Energy Independent Power Project Procurement Programme (REIPPPP) round 4, for which financial close was initially anticipated in 2015. C = competitive tender; DN = direct negotiation; MW = megawatts; REFiT = renewable energy feed-in tariff.

In Kenya, Tanzania, and Nigeria, serious power shortages motivated these first IPP procurements. These countries' experiences with competitive procurement were negligible at the time, and there was a general perception that direct negotiation would allow quick fixes. Interestingly, in both Kenya and Tanzania competitive tenders were already under way for other installations, but were passed by for stopgap measures. In the case of one Tanzanian project (IPTL), the time between financial close and procurement spanned five years amid the arbitration of a project dispute; thus, direct negotiation was not a quick fix in the least.

Other than this project, most of these fast-track projects did come online rapidly. But the contract changes or challenges they met at a later date could easily be ascribed to their fast-track nature.

Take, for instance, AES Barge in Nigeria: the initial plant size increased from 90 MW to 270 MW and the project also saw a change in fuel, from liquid fuel to natural gas—both of which had the effect of reducing the capacity charge. It took five years of arbitration to resolve a disagreement over the payment due for deficient availability, among other issues, and a tax exemption certificate was withheld by the government for the duration of the project. In the case of Westmont in Kenya, tariffs met with public disapproval, along with allegations of corruption, but there was no outright contract change. Westmont would not, however, negotiate a second contract after its initial seven-year contract expired (amid a failure to agree on rates), and the project was terminated—in contrast to Iberafrica (also in Kenya), which voluntarily lowered rates prior to contract renegotiation.

While the first IPPs in the five cases were all directly negotiated, subsequent private power projects have not followed a clear pattern. Both Kenya and Tanzania opted for the competitive procurement model, reverting to projects that were already under way and clearly identified in the country's master plans. Importantly, competitive procurement was made a precondition for access to multilateral funding streams and later guarantees. In these two countries, the first set of IPPs were perceived to be costly experiments, prompting demand for greater accountability and scrutiny in subsequent IPP projects.

Nigeria, Uganda, and South Africa, meanwhile, continued to use direct negotiations to procure private power, despite the costs observed in earlier such negotiations. This points to potentially deeper issues surrounding how countries perceive the cost of funding and the benefits of various procurement methods, particularly in the face of power cuts as well as initial IPP experiences. Uganda's experience (presented in box 4.4) provides an illustrative example of how policy makers' perceptions of competitive procurement may be erroneous.

Neither procurement method has, however, been a foregone conclusion. For instance, direct negotiations have subsequently been used in Kenya and Tanzania, albeit intermittently, and competitive tenders have finally emerged in South Africa and Uganda, alongside further procurement by direct negotiation. This reinforces the dynamic highlighted in figure 4.1: a recurring wave of competitive tenders and direct negotiations across the pool is also now seen at the country level. Nigeria is the one country among the five with no record of competitive procurement, although once the Transitional Electricity Market (TEM) is fully functional, it intends running competitive tenders as stipulated by the Nigerian Electricity Regulatory Commission (NERC), the electricity regulator.

It is important to reiterate here that direct negotiations are often the result of unsolicited bids and frequently occur within the context of power shortages. This scenario is very common in countries where planning capacity is weak and generation expansions are not effectively programmed and procured in a timely manner. Competitive tenders, in contrast, ideally follow from up-to-date power plans and are initiated with sufficient time to allow for a well-designed procurement process. The risks and often poor outcomes associated with procurement processes delinked from generation expansion plans and based on direct negotiation, in contrast to well-planned and well-run tenders, come to the fore when comparing the experiences of Kenya and Tanzania, as presented in box 4.5.

The Scope for Competition in Sub-Saharan Africa

Competitive tenders are intended to bring about more affordable, higher-quality power through a transparent bidding process. This is more likely the case when tenders attract an adequate number of investors. In the ideal scenario, one project

Box 4.4 Direct Negotiations and Competitive Procurement in Uganda

In Uganda, competitive tenders for large-scale independent power projects (IPPs) are perceived by some in government as costly and time consuming and, hence, not in line with the ultimate goals of a reliable power system and reduced generation prices. The government of Uganda believes that, in the end, public projects involve less expenditure because they involve fewer transaction costs between lenders. Also, it is assumed that private investors come with higher expectations of returns—framed by some government officials as the "hidden cost" or "premium" of private financing. Such perceptions are understandably—but, nevertheless, erroneously—shaped by the comparison of the fully depreciated, government-owned Nalubaale and Kiira, and the privately sponsored Bujagali hydroelectric plants.

Whereas the former projects sell electricity to the utility at an estimated U.S. cents (USc) 1.2 per kilowatt-hour (kWh), Bujagali-generated electricity is bought at roughly USc 10 or more. For the Karuma and Isimba hydropower projects, both under construction and both financed in part by Chinese funding, the government publicly communicates an expected tariff range of USc 4–6/kWh. Development partners as well as the private sector have questioned these numbers and, indeed, a closer look at current cost estimates and the financing conditions under discussion do not necessarily verify the government's expectations. With $3.44 million/megawatt (MW), the Bujagali hydropower plant (HPP) ranks among the most expensive projects of this scale in the world (overview in IRENA [2012]). The Karuma HPP, meanwhile, has competitive cost levels, at an estimated $2.34 million/MW. Nonetheless, the Isimba HPP, at $3 million/MW, is not significantly cheaper than the Bujagali HPP on a per unit level.

Amid the frequent cost overruns of large hydropower projects, the effective margin of public over private projects could decrease more.

The other main argument in favor of a direct award is its comparatively shorter implementation timeline. The public perception is that the full procurement cycle for Bujagali took more than 12 years. In contrast, the implementation of the similar-sized Kiira hydropower project in the early 2000s is recorded—and wrongly so—as having been completed without complications and delays. With an estimated six years from the award to the expected commissioning of the Karuma and Isimba hydropower projects, a competitive procurement process following all (international) legalities and formalities cannot compete. It could, however, be argued that competition was not the reason for any failure associated with Bujagali, but rather the institutional arrangements of its implementation, especially the exclusion of external experts in the procurement process and decision-making bodies. Furthermore, the first failed attempt to implement Bujagali was the result of a flawed direct award process, which in the end had to be aborted after the detection of corruption.

Source: Compiled by the authors, based on various primary and secondary source data.

receives a dozen bids and the fierce competition drives down prices and, optimally, pushes up quality.

With the notable exception of South Africa, no tender in Africa has attracted a dozen bidders over the course of the two-decade experience with IPPs. As seen in table 4.7, tenders in the five case study countries have generally attracted two

Box 4.5 A Comparison of Competitive Tenders and Direct Negotiations in Kenya and Tanzania

Kenya has run a series of successful competitive procurements for new thermal power. In the most recent round, in 2010, the Kenya Power and Lighting Company (KPLC) began a competitive procurement for three diesel generators of approximately 80 megawatts (MW) each, culminating in Thika (87 MW), Triumph (83 MW), and Gulf (80 MW). For Thika alone, 9 bids were received (after 17 firms drew tender documents). Local sponsors are noted in two of the three projects, and partial risk guarantees (PRGs) helped shore up competitive financing. The three projects are deemed success stories in terms of the ultimate cost and reliability of power.

Kenya had a dynamic power-planning process, chaired by the regulator, the Energy Regulatory Commission, but involving all relevant stakeholders. New build opportunities were allocated to either the national power generation company, KenGen, or to private independent power projects, which were procured via competitive tenders run by the KPLC. Separated from KenGen, and housing the system operator, the KPLC does not face any generation investment conflicts and is able to procure new power in a fair, transparent, and competitive fashion. The KPLC built up considerable internal procurement and contracting capabilities and was able to run timely and effective procurement processes. But more recently, the landscape for new build opportunities has been somewhat clouded by the involvement of the government's Geothermal Development Company and direct negotiations for wind projects. The power-planning system today relies on optimistic demand assumptions, and unfortunately no longer offers a clear link to the timely initiation of competitive tenders by a central procurement unit.

Tanzania's record stands in contrast to Kenya's. It produces irregular power master plans that never translate into timely competitive tenders. Instead, the Ministry of Energy and Minerals is inundated with unsolicited proposals formalized into memorandums of understanding with project developers, some without an established track record. The ministry has struggled to assess the value of these projects and procurement has been often delayed.

An example is the Richmond (now Symbion) project. Agreement was struck, in a nontransparent manner, with Richmond, a special-purpose vehicle formed in 2006 to provide 100 MW of emergency power. The contract was stipulated for two years starting in September 2006 (20 MW) followed by the balance (80 MW) by February 2007, which was safeguarded by a government guarantee. The first 20 MW (of the 100 MW) was brought online in October 2006, and fueled with natural gas supplied by Songo Songo. This occurred only after the government advanced Richmond funds, as neither the parent company (which it turns out was a publisher with no prior experience in power supply) nor the subsidiary (operating from a residential address in Houston) had money to lift the generators. Dowans Holdings, based in the United Arab Emirates (UAE), subsequently bought the plant and took over the contract, and saw the addition of 60 MW capacity, albeit only by August 2007—six months later than expected. When the plant finally came online it was not fully functioning and by the time all issues had been resolved Tanzania was no longer in need of the power, yet was legally contracted to purchase it or pay penalties. The Richmond/Dowans fallout led to the resignation of Prime Minister Edward Lowassa and two ministers in 2008 amid associated corruption allegations.

Source: Compiled by the authors, based on various primary and secondary source data.

Table 4.7 Sample of Competitive Tenders in Selected Countries, Sub-Saharan Africa

Year	*Project*	*No. of bids*	*Country*
1999	Azito	3	Côte d'Ivoire
1999	Kipevu II/Tsavo	3	Kenya
1999	OrPower4	2	Kenya
2001	Songas—Songo Songo Gas-to-Power Project	2	Tanzania
2005	Saint-Louis-Dagana-Podor Rural Electrification	2	Senegal
2007	Bujagali Hydro Project	3	Uganda
2008	Namanve Power Plant	3	Uganda
2008	Rabai Power Plant	4	Kenya
2012	Thika Thermal Power Project	9	Kenya
2015	GETFiT PV (Tororo North/South and Soroti I/II)	7 (for 2 projects each)	Uganda

Source: Compiled by the authors, based on various primary and secondary source data.
Note: GETFiT = global energy transfer feed-in tariff; PV = photovoltaic.

to three bidders, surely not enough to ensure strong competition. However, the results have slowly improved since 1999 and there is notable development in the case of Kenya.

The Advantages of Competition: Better Transparency and Price Outcomes

The obvious advantage of competition is that it affords greater transparency in the procurement process and therefore helps ensure that new generation capacity is procured fairly and at the least cost.

Direct negotiation restricts options and the possibility to strike the best deal. All too often, unsolicited bids result in nontransparent memoranda of understanding (MoUs) and contracts, sometimes linked to allegations of corruption. In contrast, published requests for qualification (RfQs), requests for proposals (RfPs), and evaluation and award processes provide transparency and certainty in the market and potentially generate a pipeline of investors. Transparency and market interest are further enhanced if competitive tenders are linked to regularly updated generation expansion plans.

The experience of the case study countries demonstrates that the competitive procurement of IPPs provides clear price advantages, despite the relatively low number of bidders in many of these tenders.

As seen in table 4.8, competitively bid OCGTs and CCGTs are consistently less costly than directly negotiated capacity using the same technologies. Procurements of medium-speed diesel (MSD)/HFO power engines by competitive tender and direct negotiations appear to be largely comparable, whereas wind shows the advantage of competitive tenders (based on South Africa's round 3 REIPPPP data) over both REFiT and direct negotiation.

Table 4.9 provides a series of price comparisons, based on data from case study countries.[10]

Looking at the projects listed in table 4.9, the MSD/HFO procured via competitive bidding appears to be less expensive (as measured by USc/kWh) than that procured through direct negotiation, setting aside exogenous factors

Table 4.8 Cost Comparison of Directly Negotiated and Internationally Competitive Bid Projects, by Technology, 1994–2014
US$/kilowatt-hour

Technology/procurement	*Directly negotiated*	*Competitive tender*	*REFiT*
OCGT	977	833	n.a.
CCGT	1,145	1,038	n.a.
MSD/HFO	1,526	1,534	n.a.
Onshore wind	2,870	2,180	2,500

Source: Based on the authors' calculations.
Note: Biomass, coal, geothermal, methane, and solar PV are excluded from this comparison as there was only one procurement type, that is, either direct negotiation or competitive tender, not both. Hydropower has also been excluded as costs are site specific (hydrology and geology). The data on competitive tenders for wind are from Window 3 of the REIPPPP. Some projects from the database have also been excluded because they include gas or fuel infrastructure costs and, at the time of writing, separate power plant costs were not available for comparative purposes. CCGT = combined-cycle gas turbine; HFO = heavy fuel oil; kW = kilowatt; MSD = medium-speed diesel; OCGT = open-cycle gas turbine; PV = photovoltaic; REFiT = renewable energy feed-in tariff; REIPPPP = Renewable Energy Independent Power Project Procurement Programme; n.a. = not applicable.

Table 4.9 Cost Comparison of Medium-Speed Diesel/Heavy Fuel Oil Generators, 2013–15
USc/kilowatt-hour

MSD/HFO-country (year of financial close), project name	*Competitive tender*	*Directly negotiated*
MSD/HFO-Tanzania (1997), IPTL	n.a.	31
MSD/HFO-Uganda (2009), Tororo	n.a.	27.09
MSD/HFO-Uganda (2008), Namanve	24.08	n.a.
MSD/HFO-Kenya (1996), Iberafrica	n.a.	25
MSD/HFO-Kenya (1999), Tsavo	22	n.a.
MSD/HFO-Kenya (2008), Rabai	14	n.a.
MSD/HFO-Kenya (2012), Thika	22	n.a.
MSD/HFO-Kenya (2014), Gulf	22	n.a.

Source: Compiled by the authors, based on various primary and secondary source data.
Note: There are important qualifiers, related to specific technology and location, that explain some of the cost discrepancies. Take, for instance, the case of Kenya: Rabai, the least costly IPP listed in this table, has a heat-recovery system, which improves efficiencies, and is located close to the port of Mombasa (and its fuel source). The heat-recovery system explains part of the difference in cost with the Tsavo IPP, also located in Mombasa. The Thika Power and Gulf IPP have heat-recovery systems as well, but these plants are located up-country near Nairobi and have an additional fuel cost for transportation to and from Mombasa (about 500 kilometers away). Iberafrica, located in Nairobi, which also has an additional fuel transportation cost, is similar in technology to Tsavo. HFO = heavy fuel oil; IPP = independent power project; IPTL = Independent Power Tanzania Ltd.; MSD = medium-speed diesel; USc = U.S. cent; n.a. = not applicable.

such as transmission constraints and dispatch regimes that impact on capacity factors and hence price.

Price outcomes for solar and wind energy[11] projects can be compared more reliably, since they are self-dispatched and have fixed tariffs. The next section presents the experience of South Africa, where competitively bid wind projects have far lower price outcomes than the directly negotiated Lake Turkana project in Kenya, despite its vastly superior wind resources. Competitively bid solar PV projects in South Africa and Uganda are also more competitive than the directly negotiated projects in Rwanda and Nigeria.

The Impressive Results of Competitively Bid Wind and Solar Projects in South Africa

South Africa provides a striking example of the superior outcomes associated with the competitive procurement of wind and solar projects, which have delivered prices comparable to the very sophisticated auction system developed in more mature power markets, such as Brazil (whose experience is presented in the next section).

Following the abandonment of the REFiT program in 2011, South Africa moved to competitive tenders for grid-connected renewable energy with the REIPPPP. An IPP office was set up by the National Treasury in cooperation with the Department of Energy (DoE), and the first RfP was launched in August 2011.

The REIPPPP envisioned the procurement of 3,625 MW of power over a maximum of five tender rounds. Another 100 MW was reserved for small projects below 5 MW that were procured in a separate program for small IPPs. Caps were set on the total capacity to be procured for individual technologies—the largest allocations were for wind and PV, with smaller amounts for concentrated solar, biomass, biogas, landfill gas, and hydropower. The rationale for these caps was to limit the supply to be bid out and therefore increase the level of competition among the various technologies and potential bidders.

The tenders for different technologies were held simultaneously. Interested parties could bid for more than one project and more than one technology. Projects had to be larger than 1 MW; the upper limit set on bids differed by technology—for example, 75 MW for a PV project, 100 MW for a concentrated solar power (CSP) project, and 140 MW for a wind project. Caps were also set on the price for each technology (at levels not dissimilar to the National Energy Regulator of South Africa's [NERSA's] 2009 REFiTs). Bids were due within three months of the release of the RfP, and financial close was to take place within six months after the announcement of preferred bidders.

Twenty-year PPAs, denominated in South African rand (R), were to be signed by the IPPs and Eskom, the off-taker. IPPs and the DoE were to sign implementation agreements (IAs), which included a sovereign guarantee of payment to the IPPs, by requiring the DoE to make good on these payments in the event of an Eskom default. The IAs also placed obligations on the IPP to deliver economic development targets. Direct agreements (DAs) provided step-in rights for lenders in the event of default. The PPA, IA, and DA were nonnegotiable contracts and were developed after an extensive review of global best practices and consultations with numerous public and private sector actors. Despite some bidder reservations regarding a lack of flexibility to negotiate the terms of the various agreements, the overall thoroughness and quality of the standard documents seemed to satisfy most of the bidders participating in the three rounds.

Bids were required to contain information on the project structure; legal qualifications; and land, environmental, financial, technical, and economic development qualifications. Bidders had to submit bank letters indicating that financing was locked in—a highly unusual practice outsourcing due diligence to the banks. Effectively, this meant that lenders took on a higher share of project development risk, in an arrangement that addressed the biggest problem with auctions—the “low-balling” that results in deals not closing. The developers were expected to identify the sites and pay for early development costs at their own risk. Bid bonds or guarantees had to be posted, equivalent to R 100,000 ($12,500) per megawatt of nameplate capacity of the proposed facilities, and the amount was doubled once preferred bidder status was announced. The guarantees were to be released once the projects came online or if the bidder was unsuccessful after the RfP evaluation stage.

Approximately 130 local and international advisers were used by the DoE’s IPP office to develop the RfP and evaluate the bids in the first round, at a total cost of approximately $10 million. Many of these advisers had been involved in the initial design process.

The bid evaluation involved a two-step process. First, bidders had to satisfy certain minimum threshold requirements in six areas: environment, land, commercial and legal, economic development, financial, and technical. For example, the environmental review examined approvals while the land review looked at tenure, lease registration, and proof of land-use applications. Commercial considerations included the project structure and the bidders’ acceptance of the PPA. The financial review included standard templates used for data collection that were linked to a financial model used by the evaluators. Technical specifications were set for each of the technologies. For example, wind developers were required to provide 12 months of wind data for the designated site and an independently verified generation forecast. The economic development requirements, in particular, were complex and generated some confusion among bidders.

Bids that satisfied the threshold requirements then proceeded to the second step of evaluation, where bid prices counted for 70 percent of the total score, with the remaining 30 percent given to a composite score covering job creation, local content, ownership, management control, preferential procurement, enterprise development, and socioeconomic development. The 70/30 split was new in public procurement and decreased the weight of price considerations over economic development considerations compared with the usual 90/10 split mandated by the government.

Bidders were asked to provide two prices: one fully indexed for inflation and the other partially indexed, with the bidders initially allowed to determine the proportion that would be indexed. In subsequent rounds, floors and caps were instituted for the proportion that could be indexed.

The detailed results of the first four rounds are shown in table 4.10.

In the first round, 53 bids for 2,128 MW of power-generating capacity were received. Ultimately 28 preferred bidders were selected, awarding 1,425 MW for a total investment of nearly $6 billion. Successful bidders realized that not enough projects were ready to meet the bid qualification criteria, and that all qualifying bids were thus likely to be awarded contracts. Bid prices in the first round were thus close to the price caps set in the tender documents. Major

Table 4.10 Results of South Africa's Efforts to Procure Renewable Energy Independent Power Projects, by Bidding Round

Bidding round	*Wind*	*PV*	*CSP*	*Hydro*	*Biomass*	*Biogas*	*Landfill*	*Total*
Round 1								
Capacity offered (MW)	1,850	1,450	200	75	12.5	12.5	25	3,625
Capacity awarded (MW)	648.5	626.8	150	0	0	0	0	1,425.3
Projects awarded	8	18	2	0	0	0	0	28
Average tariff (Rc/kWh)	114	276	269	n.a.	n.a.	n.a.	n.a.	n.a.
Average tariff (USc/kWh) R 8/$	14.3	34.5	33.6	n.a.	n.a.	n.a.	n.a.	n.a.
Total investment (R, millions)	13,312	23,115	11,365	0	0	0	0	47,792
Total investment (US$, millions) R 8/$	1,664	2,889	1,421	0	0	0	0	5,974
Round 2								
Capacity offered (MW)	650	450	50	75	12.5	12.5	25	1,275
Capacity awarded (MW)	558.9	417.12	50	14.4	0	0	0	1,040.42
Projects awarded	7	9	1	2	0	0	0	19
Average tariff (Rc/kWh)	90	165	251	103	n.a.	n.a.	n.a.	n.a.
Average tariff (USc/kWh) R 7.94/$	11.3	20.8	31.6	13	n.a.	n.a.	n.a.	n.a.
Total investment (R, millions)	10,897	12,048	4,483	631	0	0	0	28,059
Total investment (US$, millions) R 7.94/$	1,372	1,517	565	79	0	0	0	3,533
Round 3								
Capacity offered (MW)	654	401	200	121	60	12	25	1,473
Capacity awarded (MW)	787	435	200	0	16.5	0	18	1,456.5
Projects awarded	7	6	2	0	1	0	1	17
Average tariff (Rc/kWh)	74	99	164	n.a.	140	n.a.	94	n.a.
Average tariff (USc/kWh) R 9.86/$	7.5	10	16.6	n.a.	14.2	n.a.	9.5	n.a.
Total investment (R, millions)	16,969	8,145	17,949	0	1,061	0	288	44,412
Total investment (US$, millions) R 9.86/$	1,721	826	1,820	0	108	0	29	4,504
Round 3.5								
Capacity offered (MW)	n.a.	n.a.	200	n.a.	n.a.	n.a.	n.a.	200
Capacity awarded (MW)	n.a.	n.a.	200	n.a.	n.a.	n.a.	n.a.	200
Projects awarded	n.a.	n.a.	2	n.a.	n.a.	n.a.	n.a.	2
Average tariff (Rc/kWh)	n.a.	n.a.	153	n.a.	n.a.	n.a.	n.a.	153
Average tariff (USc/kWh) R 10.52/$	n.a.	n.a.	14.5	n.a.	n.a.	n.a.	n.a.	14.5
Total investment (R, millions)	n.a.	n.a.	18,319	n.a.	n.a.	n.a.	n.a.	18,319
Total investment (US$, millions) R 10.52/$	n.a.	n.a.	1,742	n.a.	n.a.	n.a.	n.a.	1,742
Round 4 (a)								
Capacity offered (MW)	590	400	0	60	40	0	15	1,105
Capacity awarded (MW)	676.4	415	0	4.7	25	0	0	1,121.1
Projects awarded	5	6	0	1	1	0	0	13
Average tariff (Rc/kWh)	61.9	78.6	n.a.	111.7	145	n.a.	n.a.	n.a.
Average tariff (USc/kWh) R 12/$	5.2	6.6	n.a.	9.3	12.1	n.a.	n.a.	n.a.
Total investment (R, millions)	13,466	8,504	0	245	1,195	0	0	23,410
Total investment (US$, millions) R 12/$	1,122	708.7	0	20.4	99.6	0	0	1,950.7

table continues next page

Table 4.10 Results of South Africa's Efforts to Procure Renewable Energy Independent Power Projects, by Bidding Round *(continued)*

Bidding round	*Wind*	*PV*	*CSP*	*Hydro*	*Biomass*	*Biogas*	*Landfill*	*Total*
Round 4 (b)[a]								
Capacity offered (MW)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0
Capacity awarded (MW)	686.4	397.9	0	0	0	0	0	1,084.3
Projects awarded	7	6	0	0	0	0	0	13
Average tariff (Rc/kWh)	71.6	85.1	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Average tariff (USc/kWh) R 12.5/$	5.7	6.8	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Total investment (R, millions)	15,329	8,363	0	0	0	0	0	23,692
Total investment (US$, millions) R 12.5/$	1,226.3	669	0	0	0	0	0	1,895.3
TOTALS								
Capacity offered (MW)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Capacity awarded (MW)	3,357.2	2,291.82	600	107.7	41.5	0	18	6,327.62
Projects awarded	44	35	7	3	2	0	1	92
Total investment (R, millions)	69,973	60,175	33,797	876	2,256	0	288	167,365
Total investment (US$, millions) R 12.5/$	7,105.3	6,609.7	5,548	99.4	207.6	0	29	19,599

Source: Compiled by the authors based on DoE presentations and data provided by the DoE IPP Unit.
Note: R/US$ conversions are relevant for the date on which contracts were signed in each bid window. These data are representative at the time of bidding. Contracted capacity and investment amounts changed slightly at the time of financial close. CSP = concentrated solar power; DoE = Department of Energy; IPP = independent power project; kWh = kilowatt-hour; MW = megawatt; PV = photovoltaic; R = rand; Rc = rand cent; USc = U.S. cent; n.a. = not applicable.
a. Round 4b was an additional award. Due to numerous low-priced bids in round 4, after the initial award of preferred bidders (now referred to as 4a), it was decided to double the award (referred to as 4b). There was no official prior allocation for 4b—simply an additional award based on the next cheapest projects bid in the original round 4.

contractual agreements were signed on November 5, 2012; most projects reached full financial close shortly thereafter. Construction on all of these projects has since commenced, and the first project came online in November 2013.

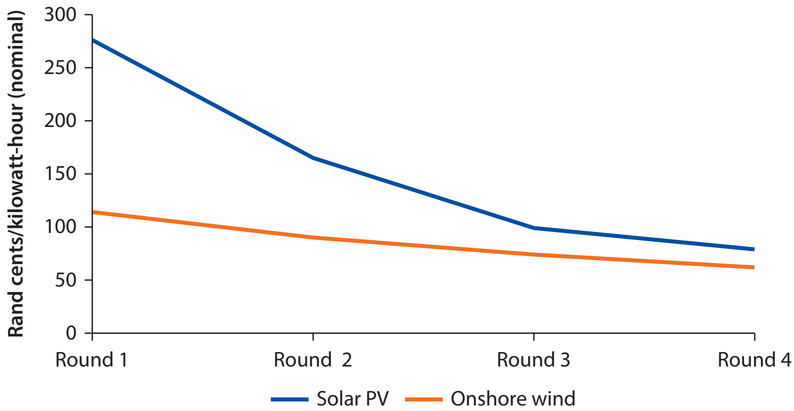
A second round of bidding was announced in November 2011. The total amount of power to be acquired was reduced, and other changes were made to tighten the procurement process and increase competition. Seventy-nine bids for 3,233 MW were received in March 2012, and 19 bids were ultimately selected. Prices were more competitive, and bidders also offered better local content terms. IAs, PPAs, and DAs were signed for all 19 projects in May 2013.

A third round of bidding commenced in May 2013, and again, the total capacity offered was restricted. In August 2013, 93 bids were received, totaling 6,023 MW. Seventeen preferred bidders were notified in October 2013, totaling 1,456 MW. Prices fell further in round three. Local content again increased, and financial close was expected in July 2014, but has been delayed a number of times because of uncertainties around Eskom transmission connections.

A fourth round of bidding commenced in August 2014; 13 preferred bidders were announced in April 2015, totaling 1,121 MW. Prices were so low that an extended allocation was made in June 2015 for an additional 13 projects totaling 1,084 MW.

As it can be clearly seen, bid prices fell across rounds (figure 4.2). In particular, in round 4 the price for solar PV was less than a fifth of the price in round 1. The price for onshore wind decreased to a third of what it had been.

Figure 4.2 Average Bid Prices for Independent Power Projects Using Renewable Energy, South Africa



Source: Compiled by the authors, based on various primary and secondary source data.
Note: PV = photovoltaic.

Increased competition was no doubt the main driver of the fall in prices in rounds two and three. But there were other factors as well. International prices for renewable energy equipment have declined over the past few years amid a glut in manufacturing capacity as well as ongoing innovation and economies of scale. The REIPPPP was well positioned to capitalize on these global factors. Transaction costs were also lower in subsequent rounds, as many of the project sponsors and lenders became familiar with the REIPPPP tender specifications and process.

As renewable energy prices are reaching grid parity, it is possible for other African countries to explore what they might learn from the South African REIPPPP through lowering transaction costs and designing competitive tenders appropriate to local markets.

Competitive Procurement Elsewhere in the World: The Brazilian Model

When considering effective mechanisms for procuring new generation capacity, it is useful to explore the experience of other regions and countries. Brazil is a case in point. Brazil's auction-based power market is among the most sophisticated and efficient in the world. How did Brazil come to use the auction mechanism and how does it work in practice? Prompted by a deep financial and operational crisis in its power sector, Brazil commenced reforms in 1998. A competitive wholesale market was created with a spot market as well as independent institutions responsible for sector regulation and monitoring and market administration. Importantly, the reforms also targeted improvements in the technical and financial performance of utilities. In this early reform period, however, investors did not always receive the right signals for the long-term expansion of generation capacity in line with increasing demand. With a significant share of capital-intensive hydropower in the generation mix, Brazil was forced to fall back to energy rationing during dry periods, especially in 2001–02. The energy crisis triggered a second wave of reforms that began in 2004. These focused on delivering adequate power supply and on the centralized planning of power expansion. Competitive tenders or auctions were used to build and operate new generation and transmission facilities. Also, to provide more revenue certainty and to attract long-term financing for new power capacity, long-term bilateral contracts between the new IPPs or transmission companies and financially viable distribution companies (DisCos) were made mandatory. As of today, although the state-owned company, Eletrobras, remains one of the most important players in generation and transmission, private sector participation is extensive, not only in distribution but also in most new generation and transmission additions. Customers supplied by distribution companies account for 70 percent of total electricity consumption. Each distribution company has to estimate the growth in demand from its regulated customers, and these demand projections are aggregated to determine required supply capacity in centrally organized auctions. Distribution companies cannot negotiate contracts bilaterally with suppliers outside these auctions. There are separate auctions for new energy (new generation investments) and existing energy (renewal of contracts from existing generators) to ensure the security of supply. A detailed analysis of the auction process is presented in box 4.6.

Multiple auctions have been held each year, with impressive capacity and price outcomes. Sixty-five gigawatts of new capacity have been contracted (40 percent hydropower, 33 percent renewable energy, and 27 percent thermal) and wind prices are now as low as USc 5/kWh. PPAs include capacity factors of the plant that have to be guaranteed by the IPP, and penalties in case actual production is lower than the guaranteed value. This analysis of the Brazilian energy auction and contracting system demonstrates the significance of the second wave of power sector reforms that have swept across Latin America (and some other emerging economies), aimed at incentivizing and facilitating new investment in power generation. Africa's power sector reforms have not progressed as far. Understandably, the level of sophistication reached in Latin America does not fit the reality of most African countries, constrained as they are by structural issues such as weak public sector capacity, vulnerable economies, and weak investment climates. Nonetheless, what is important about Brazil's experience is not the type or degree of reforms put in place, but rather the key principles underpinning reforms: openness and transparency in the planning of power expansion, transparency and predictability in the competitive procurement of generation capacity, and robust oversight by the ministry and the sector regulator. It is important to note that the reforms first commenced with efforts to improve the operational and financial sustainability of electricity distributors. These distributors then had to take responsibility for securing adequate power through a centrally managed, fully competitive procurement process.

Box 4.6 How the Brazilian Energy Auction Works

Auctions are run annually and are designed according to project lead times, contract duration, technology type, and adjustments. In addition, there are sporadic auctions that are project specific or for reserve energy. The Brazilian Electricity Regulatory Agency (ANEEL) publishes draft contracts and more detailed requirements. Developers then submit technical details of their projects to the Brazilian Energy Research Agency (EPE)—reporting to the Ministry of Energy and Mines (MME), which announces the projects qualified to participate in the auction.

All existing, new, and reserve energy auctions have followed a hybrid design, divided into two phases: a "descending price clock auction," followed by a final "pay as bid" round through sealed bids.

Prior to the auction, the MME decides two important undisclosed parameters: the "total demand," representing the maximum energy amount that will be contracted, provided that there is sufficient supply; and the "demand parameter," which is used to force a minimum level of competition. For example, if the demand parameter is equal to 1.5, this means that the auction's supply must be at least 50 percent higher than the auction demand—and, therefore, if supply is insufficient, the demanded quantity will be automatically adjusted downward.

In the first step of the descending clock phase, the bidders confirm the quantity of electricity (in gigawatt-hours per year) they are willing to commit at the auction's ceiling price (disclosed in advance and specific to each technology). This quantity cannot be revised in later rounds, even as the offered price decreases. In addition, at this point, the single "total demand," previously defined by the MME, is allocated to various technologies in proportion to the supply confirmed for each technology, unless the MME has specified a ceiling for a specific technology (in which case the lowest-cost technology on offer makes up the difference). Having thus defined the demand for each technology, and the quantity offered by each of the bidders, the auction continues with the subsequent rounds of the descending clock phase. Multiple rounds take place, in which the auctioneer announces the new price level and bidders confirm whether they wish to continue in the auction (with the full quantity initially offered) or not. This phase is terminated when the overall supply becomes smaller than the auction's demand plus a certain adjustment factor ("demand parameter") unknown by the bidders. The bidders that remain in the auction proceed to a sealed-bid auction. Bidders are still not allowed to revise the initial quantities offered and they cannot offer a price higher than the ceiling price at which the descending clock phase was terminated. What the bidders know for sure is that the supply is greater than the demand, which incentivizes them to further lower their bids in the sealed-bid phase. Experience has shown that this second phase can result in price reductions of up to 15 percent, although less than 5 percent has been more common.

The bids are then selected in an ascending order until demand is matched or surpassed. The contracts are priced as bid. Most are standard take-or-pay energy contracts in which the buyer pays a fixed amount per megawatt-hour for the energy contracted, and the seller must deliver the contracted energy, clearing the difference between the energy produced

box continues next page

Box 4.6 How the Brazilian Energy Auction Works *(continued)*

and contracted in the spot market. In some availability contracts, however, distribution companies pay a fixed amount for available capacity in addition to the variable operating costs and short-term market transactions. Contract values are escalated annually according to defined indexes.

Winning bidders sign direct contracts with distribution companies in proportion to their forecasted demand and then conclude financing agreements with banks (principally with the Brazilian Development Bank, BNDES, which offers concessionary finance for auction winners).

The mandatory bilateral contracts between new generators and financially viable distribution companies introduced in 2004 have two basic rules:

- Every load in the system must be 100 percent covered by a supply contract. This means that each kilowatt-hour consumed in the system, regardless of whether it comes from free consumers or from regulated consumers, must be supported by an energy contract. The distribution utilities are responsible for contracting energy for their regulated consumers, while each free consumer is responsible for contracting its own consumption.
- Every energy contract must be backed up by Firm Energy Certificates (FECs), which are calculated by the MME using probabilistic production-costing models. These certificates represent a generator's expected capacity to produce energy in a sustainable fashion, following a predefined supply reliability criterion.

After signing the power purchase agreements, the project developers are required to deposit a completion bond of 5 percent of the estimated investment cost of their project. If delays exceed one year, ANEEL has the right to terminate the contract and to keep the financial guarantee. To date, no penalties have been applied, although delays with the permits for power transmission and environmental safeguards have occurred for a number of projects. The distribution companies also have to sign a guarantee contract with the energy seller and the bank, mitigating the credit risk. Distribution companies' bank accounts are required to hold at least 1.5 times the average monthly payments to energy sellers. Federal laws prohibit defaulting distribution companies from adjusting their consumer tariffs; such companies also risk losing their concessions.

Source: Compiled by the authors from two notes on power sector reforms and energy auctions in Brazil, one by Antmann (2012), and another by Lino and others (2015).

Summary: Competitive Tenders versus Directly Negotiated, Unsolicited Offers

The analysis in this chapter has shown that there are benefits to competitive bidding in terms of transparency and lower price. Competition is also associated with good practices, such as transparent tendering and contracting procedures or standard contracts with fair risk allocation, which increase predictability and therefore lower perceived risks by prospective investors. As demonstrated by the South African REIPPPP and the Uganda GETFiT program, multiple bid rounds enable the progressive improvement of documentation and contracts; they build investor confidence and a pipeline of bankable projects, which can more easily reach financial close and commissioning.

Despite the obvious benefits associated with competition, there are a number of common arguments against competitive procurement. First, competitive tenders are considered more complex and expensive than their directly negotiated counterparts. Second, competitive tenders take too long, especially if emergency power is required. Third, there is often insufficient private interest to justify competitive tenders. Fourth, the first developer or sponsor who conceives the project may be unwilling to compete via a tender due to proprietary data, technology, and/or initial investment. These arguments are used mainly by private developers, but the first and second have been used by public stakeholders as well to justify unsolicited proposals. Yet, there are viable responses to each argument raised.

Competitive tenders/auctions are more complex and costly. A typical argument against competitive procurement is that tenders/auctions entail potentially higher transaction costs. These can be of different kinds and invariably affect governments and bidders. Governments may need to invest in expensive transaction advisers to prepare good-quality tender documentation and contracts, and to run the tenders or auctions. Preparing bids may prove onerous to bidders: bid bonds have to be lodged, and complying with environmental, legal, technical, and financial requirements may be expensive. Also, bidders incur these costs with no certainty that they will be awarded the contract. While direct negotiations may appear to be simpler and cheaper at the outset, in practice they are often lengthy, and governments may be ill-equipped to assess the value of unsolicited offers. Contracts are not standardized; developers propose PPAs and IAs, which skew risks unfairly to the off-taker or government. Controversy, even corruption, can bedevil these negotiations, which are often not transparent. Poorly formulated and uncompetitive unsolicited bids may unravel, meaning that projects end up taking longer than they would have through a competitive tender. South Africa’s REIPPPP and some of Kenya’s better-run tenders show that it is possible to run competitive bids efficiently and in short time frames. In these cases, the lower price outcomes of competitive tenders (with multiple bid rounds resulting in even more competitive prices) far outweigh higher transaction costs.

Competitive tenders take too long to address an immediate power emergency. Unsolicited deals have been advocated in the face of supply emergencies. Nonetheless, such a justification should not be taken for granted. A common emergency solution is a thermal plant (reciprocating engines, gas turbines) running on diesel/HFO, a standard greenfield project that can be awarded through a fast-track competitive process. Latin American countries faced with recurring power shortages made the explicit decision to ban directly negotiated deals as part of the second wave of reforms in that region. Meanwhile, it is possible to expedite solicited bids by tightening timelines and approval processes. Case studies also show that directly negotiated projects have been more prone to renegotiation and contract disputes, meaning that they were not faster.

Where investor interest is sparse, competitive tenders are not feasible. This argument holds some weight in Africa, where, as described earlier, many tenders have attracted only a couple of bids. The solution is not, however, to turn to direct negotiations. Instead, there are two viable alternatives. One is to institute a public tender that opens an unsolicited bid up to more scrutiny (even if there is only one bidder, there is always the public process to guide and oversee the bid). The second is to reconceive the project, and possibly increase its scope by bundling it with other projects, thereby making it more attractive to investors (Hodges 2003).

There are proprietary data, technologies, or original investments in place. Several strategies are proposed to deal with investors who are reluctant to lose up-front capital or proprietary information via a competitive bid. Three such examples are the bonus system, Swiss challenge, and best and final offer. In the first option, "an advantage to the original project proponent in the form of a premium used in the bidding procedure" (generally 5–10 percent) is given to the original sponsor's bid in an open tender (Hodges and Dellacha 2007: 7). In the Swiss challenge, by contrast, the original sponsor may countermatch the best offer and obtain the contract. Finally, the "best and final offer" approach permits the original sponsor to compete in a final tender round, but without giving it preference (Hodges and Dellacha 2007: 7).

Thus competitive tenders are preferable and countries should strive to use competition. This does not mean that they should never be involved in direct negotiations or unsolicited offers. In some instances there could be few other options. Competition may be hard in contexts characterized by small-size power systems, or in fragile states with poor investment climates.

Also, unsolicited proposals may lead to good deals, as long as countries are able to fully assess the value of the project, direct negotiation is run transparently, and countries have adequate transaction capacity to negotiate reasonable PPAs. Transparency is even more important in the case of direct negotiations, as a means to minimize the risk of controversy or corruption. Also, having in place a sound generation expansion plan is critical to assess whether the project is the best option in terms of cost and technology choice. Therefore, countries that pursue direct negotiation need to invest in planning capacity, obtain transaction advisory support, and strive for transparency in their procurement practices.

Notes

1. In the case of Songas, the reduction in capacity charges was facilitated by the buying down of the allowance for funds used during construction, which had ballooned during delays in construction.
2. Mtwara has been sold back to the state/Tanzania Electric Supply Company (TANESCO) and is no longer an IPP. Symbion, originally an emergency power plant, has been redefined as an IPP, though its PPA negotiations are still under way.
3. All USc/kWh prices cited are for 2013.
4. Prices fully indexed with inflation. South African rand (R)/$ exchange deteriorated from 8 to 12 over the period.

5. Lake Turkana has an initial tariff of 7.52/kWh euro cents (€c) for up to 1,684 gigawatt-hours (GWh) and €c 3.76/kWh for any additional power. Only 14 percent of the price is indexed to inflation. The Lake Turkana tariff assumes a higher capacity factor than that used in the calculation of the Kenya wind energy feed-in tariff (FiT).
6. Kinangop (developed by Aeolus Wind) is at the 12c FiT (that is, USc 12/kWh up to 223.5 GWh, and USc 6/kWh for any additional power produced and no indexation to inflation). By the third quarter of 2015, this project had been halted amid conflicts with local communities.
7. Round 1 (15), round 2 (8), round 3 (18). Pursuant to the GETFiT policy, rejected projects can apply again. Overall, more than 30 projects applied.
8. This is not true of all countries in the Sub-Saharan African pool, for example, Senegal ran a competitive tender for its first IPP, which reached financial close in 1997, and has since continued to procure via competitive tender. In the majority of Sub-Saharan African countries, however, direct negotiations were conducted for the first IPP. Dates cited here are generally indicative of the year of financial close.
9. In 1999, Kasese Cobalt (Mubuku III) started feeding excess capacity (of approximately 9 MW) into the grid. Prior to that, Mubuku I, associated with a mining project, had been evacuating electricity (approximately 5 MW) to the grid from the 1970s, when mining operations ceased. Kakira cogeneration would be the next to feed excess power, in 2003, with the first dedicated IPP emerging in 2008.
10. OCGTs and CCGTs are excluded from these price comparisons. The CCGT Songas in Tanzania, procured via international competitive bids (ICBs), is known to be priced at USc 5/kWh; however, comparable prices are not available for Nigeria's directly negotiated CCGT (Afam and Okpai), only the Multi-Year Tariff Order 2 (MYTO-2) prices of USc 6.47/kWh for successor gas and USc 7.28/kWh for new gas (for 2013). Similarly, comparable USc/kWh data are not available for AES Barge and Aba Integrated. Small hydropower are excluded from the analysis here because their prices in large part depend on hydrological and geological conditions. As a reference, though, the average cost of the 2013 ICB-bid small hydropower project in South Africa (Window 3) is USc 13/kWh (for 2013). For small hydropower in Uganda, three directly negotiated projects (in 2008 and 2009) yielded USc 12.9/kWh, 8.3/kWh, and 13.5/kWh, respectively. REFiT small hydropower, also in Uganda, with a financial close initially anticipated in 2015, ranged from USc 8.5/kWh to USc 10.1/kWh.
11. Based on the authors' data, Cabo Verde, Ethiopia, Kenya, and South Africa are the only countries in Sub-Saharan Africa with grid-connected wind installations. Ethiopia's wind is publicly financed, including via Chinese-backed funding and therefore is not part of this analysis.

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CHAPTER 5

Conclusions

Introduction

Independent power projects (IPPs) certainly make an important contribution to Africa's power needs. By enabling increasing levels of access to electricity, they promise to support economic and social growth across the continent. While public and utility financing have traditionally been the largest sources of expanded power generation capacity, IPPs, together with Chinese-funded projects, are now the fastest growing.

IPPs account for about 25 percent of investment and additional generation capacity in Sub-Saharan Africa (excluding South Africa). This is a notable share given the relatively short period during which IPPs have been in operation; however, private investment might be much higher. The challenge ahead is for African countries to create the conditions to attract more IPPs and thus help overcome the continent's power deficit.

Excluding South Africa, the major source of IPP additions have been open- and combined-cycle gas turbines (OCGTs and CCGTs), representing nearly two-thirds of IPP capacity in Sub-Saharan Africa. Second to this are IPPs involving medium-speed diesel (MSD) and heavy fuel oil (HFO), which have relied on high-price oil imports to generate power. Meanwhile, the number of IPPs relying on renewable energy sources, notably wind and solar energy, has increased manifold. These are becoming increasingly more attractive than traditional thermal sources of power, and promise to help diversify countries' energy mix and reduce the cost of power supply. In fewer than four years, South Africa has contracted more than 6 gigawatts (GW) of grid-connected wind, solar photovoltaic (PV), and concentrated solar power (CSP), and renewable energy is now supplied to the grid at prices below the average cost of supply of the national utility, Eskom.

There is no doubt that IPPs were worth the effort. But it is not only the quantum of private investment in IPPs that is relevant; equally important are investment outcomes and, markedly, the price and reliability of electricity produced.

When procured competitively, IPPs have generally delivered power at lower costs than directly negotiated projects, and their contracts have held better.

The analysis presented in the preceding chapters shows that competitively bid project costs are lower for gas and wind turbines than directly negotiated projects. And tariffs from competitively bid diesel or HFO generators, and solar PV, are cheaper than directly negotiated contracts.

Despite these successful examples, unsolicited and directly negotiated deals have prevailed across Sub-Saharan Africa, accounting for more than 70 percent of all IPP megawatts procured. Competition still poses a conundrum in Africa, which is why this study pays particular attention to unpacking the trade-offs attached to competitive procurement.

Much of the analysis has also focused on power sector reforms and business models—which are intertwined with procurement and contracting mechanisms—and the way they influence the investment climate.

After 20 years of reform efforts in Africa, nowhere on the continent is full wholesale or retail competition to be found in power sectors. Countries that have attracted the most finance have a wide range of sector policies, structures, and regulatory arrangements. In 13 such destinations for IPP investments, vertically integrated state-owned utilities predominate. The presence of a regulator is also not definitive in attracting investment. While the countries with the most IPPs all have formally independent regulators, some countries with regulatory agencies do not have any IPPs.

Thus, what are the merits of competition? What are the key reform elements that can help African countries attract IPPs? What are the instruments that can help them strike the best deals?

Five Main Conclusions

Responses to these questions may be condensed into five main conclusions, as follows.

Systematic and dynamic power sector planning is crucial to identify generation projects that best meet a country's power needs and define the potential space for IPPs.

The analysis has shown that much more important than unbundling or privatization are the more prosaic issues of dynamic power planning and related procurement and contracting processes.

Sound planning means that countries are able to correctly project future electricity demand, decide on best supply (or demand management) options, and anticipate how long it would take to procure, finance, and build the required generation capacity.

Planning tools, such as the Least Cost Power Development Plan (LCPDP) or the Integrated Resource Plan (IRP), need to be updated regularly to reflect changing demand patterns and cost data. Planning arrangements may vary, with the planning function entrusted to the government, the regulator, a new independent planning body, or attached to an independent system operator. In several countries in Africa this function remains within the national utility, in which case the government may exercise political leadership to ensure that the incumbent utility works in the national interest. Whatever the arrangements are, it is critical that the responsible agency be resourced with adequate capacity. Planning capacity also entails clear criteria for allocating new build opportunities either to state-owned utilities (if they are present) or to IPPs. Finally, there must be an explicit link between planning and the timely initiation of generation procurement processes.

Unfortunately, far too many generation expansion master plans are not kept up to date, and even fewer are linked explicitly to the timely initiation of competitive procurement processes. These are the areas where technical assistance needs to be directed. Responsibility for planning needs to be allocated, and adequate resources devoted to building planning capacity and models. A key message is that power planning cannot be neglected.

Competitive procurement of IPPs helps ensure that projects are implemented transparently and at the lowest cost.

A common argument raised against competitive tenders or auctions is that they are complicated, take time to set up, are expensive to run, and have high transaction costs for the governments that have to hire expensive transaction advisers, and the private companies that have to spend heavily to prepare compliant bids. Unsolicited, directly negotiated contracts, it is argued, can be concluded quickly and cheaply. However, 20 years of experience in power procurement in Africa has amply demonstrated that a lack of competition in procuring new generation capacity has extensive drawbacks, ranging from the immediate effects on project outcomes—higher prices, unraveling contracts, and so on—to more general effects on the overall governance of the electricity sector and its investment climate. The lessons from Tanzania's experience with Independent Power Tanzania Ltd. (IPTL) could not be more explicit: when power is not planned, procured, and contracted transparently and consistently, the implications are potentially grave, far-reaching, and ongoing.

The assumption that direct negotiation can facilitate a rapid response in the face of supply emergencies is also erroneous. Energy solutions that entail standard thermal projects can be awarded through a fast-track competitive process. There are a number of countries where competitive tenders have been run for thermal plants in short time frames and with good outcomes. Kenya is an example. There is no reason why more countries could not benefit from competitive tenders for these standard technologies. More important, in practice, direct negotiations may be lengthy. In many cases, governments faced with multiple IPP proposals from private developers, some with poor financial track records, do not have the capacity to assess the value of the projects and lack critical transaction skills to structure reasonable power purchase agreements (PPAs). Contracts are not standardized and risks are often unfairly skewed to the off-taker or government. Nontransparent negotiations may be subject to controversy or even corruption. The experience of the five case study countries includes notable examples of directly negotiated deals that either took too long or unraveled at the end. Even if an open tender is potentially more time intensive, any time "lost" is generally made up in the life of the project, in contrast to projects that are directly negotiated and are subject to more renegotiations and contract disputes. In sum, competitive bidding is associated with greater transparency and lower costs. In addition, standard contracts result in a fair allocation of risks. And projects are more likely to move to financial close, construction, and commercial operation. These benefits are most apparent in wind and solar auctions. They are also evident in competitive bids run for gas, diesel, and HFO generators. More competitive tenders should be run in a greater number of countries, both for standard thermal technologies as well as for other technologies and contexts where competition is possible.

IPP investments in Africa will rely on long-term contracts with off-takers (most often utilities, as seen around the world) where electricity demand is growing at medium or high rates. In the future, off-takers may also be large customers. If the long-term contracts for new power are competitively bid rather than directly negotiated, then there is the potential for reduced prices.

A further benefit of competitive tenders or auctions is that they can stimulate the development of a pipeline of potentially bankable projects, especially in renewable energy. A frequent lament in Africa is that there are not enough bankable projects. Much of the emphasis is put on project development facilities and technical assistance to develop these projects. But more effort should be put into developing competitive tenders or auctions. If these are well designed, and held at regular intervals, then—as the South African Renewable Energy Independent Power Project Procurement Programme (REIPPPP) and the Uganda global energy transfer feed-in tariff (GETFiT) experiences show—investors will be willing to bid for and develop projects.

Quite simply, African governments have not done enough to offer competitive tenders or auctions with clear ground rules; standardized, long-term contracts with IPPs; effective risk mitigation; and reliable timelines. In the absence of these, project developers and funders have offered unsolicited bids. But this can change, and many would argue that it should.

Designing and running competitive tenders are not trivial tasks. But if a core government team is authorized to do the work and sufficient resources are allocated for this purpose, then experienced transaction advisers can be hired to help. And the benefits of lower prices invariably justify the initial cost of running these tenders. Once again, the South African, Kenyan, and Ugandan examples are revealing: each invested substantially in transaction advice and building capacity to design and implement competitive tenders. In South Africa's case, the National Treasury made a substantial financial allocation so that the Department of Energy (DoE)-IPP unit could hire top-rate transaction advisers. Successful projects in South Africa are required to pay a project development fee (1 percent of project cost), which goes into a DoE fund to pay for future tenders. Uganda had the support of a development finance institution (DFI) in designing effective GETFiT tenders. And Kenya learned, over successive tender rounds, how to build capacity to design and run effective tenders.

Competitive tenders for new power need to be initiated in a timely manner. It can take a year or more to run a competitive tender, and longer to reach financial close, and even longer to construct the plant. Hence, there need to be clear plans for when power is needed and a realistic timeline for its procurement.

There are examples of generation expansion plans explicitly linked to timely and competitive procurement, which in turn has yielded impressive investment and price outcomes. In South Africa, for one, there is a formal link between the promulgation of plans for the electricity sector and the allocation of megawatts for competitive auctions through ministerial "determinations." Such a system has resulted in the initiation of a series of highly successful competitive auctions for grid-connected renewable energy, with price outcomes that are comparable to those achieved in the most mature power markets internationally.

In this regard, Sub-Saharan Africa also has much to learn from the second wave of power sector reforms across Latin America, notably Brazil. Here the goal has been on planning and competition for long-term contracts that facilitate capital-intensive investments, backed by financially viable distribution utilities and appropriate risk mitigation, rather than relying on competitive wholesale spot markets. Also, all power purchased by distribution companies to meet their demand must be procured following competitive arrangements monitored by the sector regulator.

Direct negotiations with unsolicited offers are not ruled out; sometimes they are unavoidable, but countries need to strive for greater transparency and more competitive prices.

If a country still opts for an unsolicited bid, it should at least have in place effective systems and capabilities to evaluate projects and negotiate favorable contracts. A coherent generation expansion plan is a critical element, as it provides a benchmark against which to screen proposed projects and their technical parameters.

Transaction capacity is equally important. Governments that engage in unsolicited proposals or directly negotiated deals have very limited capacity to properly assess the cost-competitiveness of these projects and the technical and financial capabilities of the project developers—and thus negotiate cost-competitive contracts. As alluded to earlier, if governments are to consider unsolicited proposals, they need to contract experienced transaction advisers and, over time, build sufficient capacity to evaluate projects and to negotiate fair contracts with cost-effective outcomes and the appropriate allocation and mitigation of risks.

Open-book approaches are often adopted in these direct negotiations, with project developers sharing their financial models with governments, including projected rates of return on investment. However, there is invariably an asymmetry of information, and governments struggle to properly assess projected costs.

Of course, unsolicited bids may be opened to more scrutiny by instituting a public tender (even if there is only one bidder, the public process may be used to guide and oversee the bid). Sponsors of unsolicited projects often argue that this would be unfair because of the costs they have incurred developing their projects. Several strategies are proposed to deal with investors who are reluctant to lose up-front capital or proprietary information via a competitive bid. Three such examples are the bonus system, Swiss challenge, and the best and final offer—all of which serve to compensate or privilege in varying degrees the original proposal while simultaneously managing a competitive and transparent process.

The financial viability of utilities is a critical factor in attracting IPP investments.

IPP contracts need to be with financially viable off-takers, whether they be utilities or large customers. Again, this is an obvious point, but it needs to be restated. Most IPPs are project financed and their bankability rests on secure revenue flows. While credit enhancement and security measures can mitigate risk, a financially strong off-taker provides a sustainable basis for securing long-term contracts with IPPs.

In most African countries, state-owned utilities are the off-takers and counterparties for IPP contracts—and may remain so for the foreseeable future. The hard work still needs to be done to improve the technical and financial performance of utilities that purchase IPP power and distribute it to mostly captive customers. There is no silver bullet to accomplish this; rather, it requires a suite of strategies and interventions aimed at improved corporate governance, performance and management contracts, billing and collections, loss reductions, and so on.

A sustained effort to better the performance of utilities must be at the center of countries' reform agenda and also be consistently supported by development partners through financial and technical assistance.

Reforms, especially those improving the investment climate, remain important.

Although IPP investment trends do not appear to be correlated with specific power sector institutional arrangements, the importance of reforms geared toward promoting a sound investment climate should not be discounted.

Most electricity laws in African countries now explicitly make provision for private sector participation. Unraveling potential conflicts of interest between incumbent state-owned generators and IPPs, through unbundling generation from transmission, is in principle positive for private investment, as is more transparent contracting among state generators, IPPs, and independent transmission companies and system operators.

Having a regulator in place is especially important, for two reasons. First, as part of its oversight role, the regulator can enforce competitive procurement and ensure that power purchase costs (including those from PPAs with IPPs), which are passed on to captive customers by distribution utilities, are actually least cost. Second, much of the investment climate hinges upon effective regulation. The financial sustainability of utilities and key aspects of their performance are enhanced by sound economic regulation that is transparent, credible, and consistent.

It should be emphasized that the mere existence of a regulatory agency does not determine investment and development outcomes. The potential advantages of greater transparency and certainty in establishing revenue requirements and setting tariffs can be outweighed if regulators have insufficient capacity and make arbitrary decisions. The quality of regulation capacity is nonnegotiable: the regulator must be independent and endowed with competent—and sufficient—human resources.

In conclusion, investment in African IPPs is growing, but not fast enough. Africa does not have sufficient power. All sources of investment need to be encouraged. For IPPs to flourish, Africa needs dynamic, least-cost planning, linked to the timely initiation of the competitive procurement of new generation capacity. This must be accompanied by the building of effective regulatory capacity that encourages the distribution utilities that purchase power to improve their performance and prospects for financial sustainability—and to widen access to electricity. Such efforts promise to promote economic and social development across the continent.

PART 2

Five Country Case Studies

CHAPTER 6

Case Study 1: Kenya's Electric Power Promise

Introduction

Kenya is among the countries in Sub-Saharan Africa with the most extensive experience in independent power projects (IPPs). Its first IPPs date back to 1996, and since then the country has closed a total of 11 projects for a total of approximately 1,065 megawatts (MW) and $2.4 billion in investment.[1] While from a global standpoint these numbers are small, IPPs will soon represent more than one-third of Kenya's total installed generation capacity. Most of the plants procured over the past two decades use medium-speed diesel/heavy fuel oil (MSD/HFO); some are geothermal and wind plants. And more IPPs are on the way: for example, in September 2014, a 900–1,000 MW coal plant was awarded to a consortium led by the Kenyan companies Gulf Energy and Centum Investment Company (MoEP 2014a; African Energy 2015).[2] Despite this momentum, the actual process of procuring new geothermal and wind power has become more muddled and complex with a series of procurements conducted by the publicly owned Geothermal Development Company (GDC) and directly negotiated wind projects.

What can be learned from Kenya's IPP experience, particularly in terms of planning, procurement, and contracting? How do Kenya's IPPs measure up to their public counterparts, and what areas might require further improvement?

In the first section of this case study, a history of the sector's development is provided, followed by a description of its current structure, planning processes, and capacity. Prices and performance data are also presented. In subsequent sections, the analysis focuses on how current capacity was procured and financed (from both public and private sources), as well as on future plans. Finally, conclusions are offered related to fundamental issues that have contributed to and detracted from power generation development in Kenya.

Kenya's Electricity Sector: An Overview

Past Sector Reforms

The structure of Kenya's electricity supply may be traced back to reforms that swept the industry in the mid-1990s. As the country emerged from an aid embargo, one of the main objectives of these reforms was to attract much-needed private sector investment to complement limited public sector funding.[3]

In a policy paper on economic reforms (Government of Kenya 1996), the government stated an intention to separate the regulatory and commercial functions of the sector, facilitate restructuring, and promote private sector investment. Consequently, the Electric Power Act of 1997 was passed. The government's primary function, through the Ministry of Energy and Petroleum (MoEP), became policy formation, and its regulatory authority was devolved to a newly established Electricity Regulatory Board (ERB) that became functional in 1998. At the industry level, rationalization and unbundling redefined the scope of the Kenya Power and Lighting Company (KPLC, popularly known as Kenya Power),[4] which had served as an integrated utility since 1954.[5] Thus, from 1997 the KPLC began to focus exclusively on the transmission and distribution (T&D) of electricity, while the Kenya Electricity Generating Company (KenGen) took over all public power generation activities.

In its 2003 strategy document on economic recovery, the government expressed its dissatisfaction with the performance of the sector (Government of Kenya 2003), conceding that electricity in Kenya remained unreliable and expensive despite the reforms of the mid-1990s on. To remedy this, the strategy recommended measures to deepen reforms in the power sector. These were subsequently detailed in the national energy policy of 2004 (Government of Kenya 2004), which included an action plan for the period 2004–07 that set out the government's commitment to:

- Establish a rural electrification authority.
- Facilitate the development of a competitive market structure for the generation, distribution, and supply of electricity.
- Establish the GDC to undertake an assessment of Kenya's geothermal resources, including steam-field appraisal and development.
- Enact new legislation to, among other things, dissolve the ERB and create a new energy sector regulator—the Energy Regulatory Commission (ERC).[6]
- Accelerate the increase in the rural electrification rate by 10 percent a year.
- Partially privatize KenGen through an initial public offering of 30 percent of its equity through the Nairobi Stock Exchange.[7]

Most of these measures were implemented in the time frame identified, including the listing of KenGen on the Nairobi Stock Exchange in 2006. Exceptions were the development of a fully competitive market structure and the ambitious rural electrification target. In 2008, the Kenya Electricity Transmission Company Limited (KETRACO) was established to facilitate concessionary and donor funding in the network. The KPLC retained responsibility for operating the grid.

Further reform efforts and strategic targets followed. In 2008, Kenya's 2030 Vision (encompassing social and economic goals) set a new generation target of 23,000 MW by 2030. Rural electrification efforts would bring electricity to every home in Kenya (Ongwae 2012), with interim targets set for 2013 and 2022 (these have since been moved out to 2017 and beyond). In 2010, the government began work on a nuclear power project that has since been formalized through the Kenya Nuclear Electricity Board (KNEB), an institution within the MoEP. The initial aim was to generate 1,000 MW of nuclear energy by 2023 (Energy Monitor Worldwide 2014; Government of Kenya 2014: 46), but little progress has been made.

In September 2013, the "5,000+ MW" capacity and expansion program was launched with the goal of bringing 5,000 MW online within 40 months.[8] The program was heralded by the government of Kenya as the means to "transform Kenya, by providing adequate [generation] capacity at a comparative rate" (MoEP 2013a).[9]

Meanwhile at the generation level, the ERC affirmed that "electricity generation in Kenya is liberalized," with IPPs given an opportunity to enter the sector and compete alongside the state incumbent, KenGen (ERC 2014a). A competitive market structure is a stated goal; the proposed National Energy and Petroleum Policy and Energy Bill 2015 suggests further reforms to legal and institutional frameworks to facilitate a competitive wholesale market structure in the country. (The extent of the proposed reforms will be probed in subsequent sections.) Even with 11 IPPs present in the industry,[10] KenGen and the KPLC (both state-owned entities with significant private shareholding) remain the dominant players. There is no evidence of attempts to scale back or redefine their roles in what might be termed a hybrid market structure.

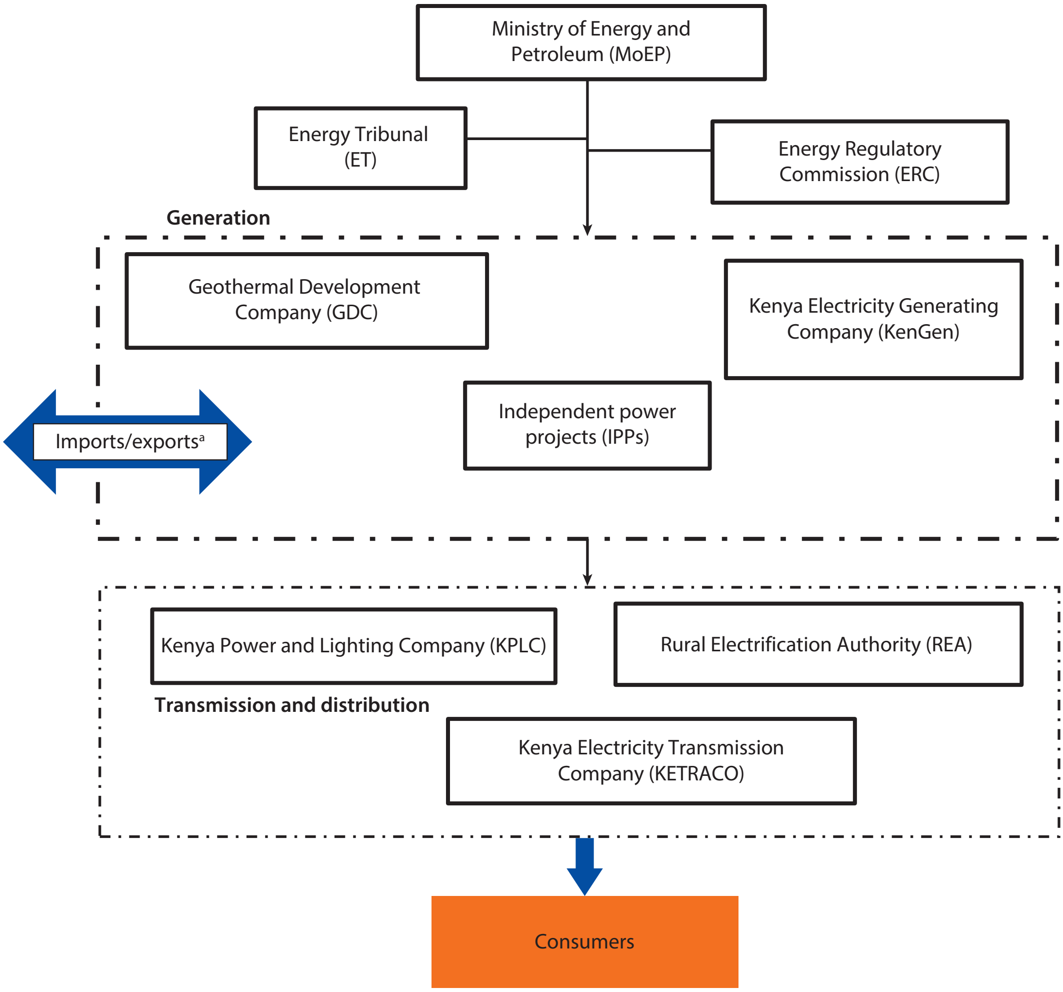
Figure 6.1 is an overview of the industry's current structure. The spaces defined as "generation" and "transmission and distribution" are still actively evolving. Also noteworthy is the anticipated growth of imports and exports.

Power Sector Practices

While detailed long-term planning is often neglected amid the urgency of power sector reform across Sub-Saharan Africa, Kenya has reasonably good mechanisms in place for the planning of least-cost generation and transmission capacity.

The 2006 Energy Act states that one of the ERC's objectives is to "prepare indicative national energy plans" (Clause 5 [g]) (Government of Kenya 2006: 22)—plans that were previously a regulatory function of the MoEP. To fulfill this new mandate, and building on the experience of the ministry, the ERC established the Least Cost Power Development Planning Committee in 2009, with representatives from the ERC (which chairs and provides the secretariat); the KPLC[11]; KenGen; KETRACO; the GDC; the MoEP; the Ministry of State for Planning, National Development and Vision 2030; the Rural Electrification Authority (REA); and the Kenya National Bureau of Statistics. Bringing these stakeholders together should enable the ERC to leverage the diverse skills and

Figure 6.1 Overview of Kenya's Electricity Sector



Sources: MoEP 2013a; Kapika and Eberhard 2013.
a. Imports and exports are as follows: Kenya buys/sells power from/to Uganda at 132 kilovolts (kV). Kenya also has cross-border trade with Tanzania and Ethiopia at 33 kV. It buys power from Tanzania at Lunga Lunga and sells to the country at Namanga, and buys power from Ethiopia at Moyale. New cross-border trade includes the following significant developments: a new 500 high-voltage direct current (HVDC) line between Ethiopia and Kenya with a power purchase agreement (PPA) signed for Kenyan imports of 400 megawatts (MW), from July 2018. A further PPA has been signed by Kenya, Rwanda, and Uganda, with Kenya exporting to Rwanda approximately 30 MW, via Uganda, starting in July 2015 (African Energy 2015).

resources (including data) required for robust planning and provide a platform for building consensus, thus ensuring the credibility of the Least Cost Power Development Plan (LCPDP)—see Ministry of Energy of Kenya 2010.

Plans are best based on solid, independent technical analysis (of, for example, the relationship between the gross domestic product [GDP], growth, and electricity demand; sectors that drive GDP growth; existing investments in infrastructure that might absorb incremental capacity; and the technical integration of technologies). In the past five years (from 2010), the demand estimates used have been directed by the government, and have tended to be unrealistically high. Linked to this, a number of generation projects have been procured through direct negotiations, and without a thorough technical and financial analysis to determine whether the proposed plants meet least-cost planning standards.

The 2011–31 LCPDP was modified to support the 5,000+ MW program, launched in 2013 by the MoEP (see annex 6A for details), and to champion the development of indigenous resources, including geothermal power, wind power, coal, and, potentially, gas.[12] Integral to the new generation program was the promise that tariffs would drop by almost half (ERC 2014b).[13] Nearly two years from its inception, the 5,000+ MW program has been radically scaled back. Plans for a liquefied natural gas (LNG) project have been shelved, and a coal project postponed well beyond any 40-month time horizon. Large LNG and coal power projects were the cornerstone of the program; together, these two developments represented the majority (3,000 MW) of the new capacity to come online, while most of the balance is associated with preexisting projects. Industry experts had long warned that massive capacity additions pose high risks to an energy sector's sustainability unless matched by demand.[14] The ideal supply profile in the critical dry season should be 15–20 percent more than the peak demand; thus, the inclusion of massive coal and LNG projects has the potential to distort Kenya's electric generation supply landscape.

The rollout and subsequent scaling back of the 5,000+ MW program sheds light on how planning and procurement are handled in the nation, as well as the role that the private sector has played and will continue to play. The LCPDP does not identify any explicit criteria for the allocation of new build opportunities, a common challenge in hybrid markets. When KenGen is unable to finance new investments, the private sector is invited to participate. Typically, bids for IPPs are requested by the KPLC, and winners selected via a competitive process, although in some cases (such as for the emergency thermal generators required in 2000 and 2011, and tenders for large LNG and coal plants in 2014) procurement has been handled by the government directly or through its appointed agent, KenGen. The government, through the Ministry of Energy (MoE), may also consider unsolicited bids.

Installed Generation Capacity

As of April 2015, Kenya's total installed capacity stood at 2,159 MW.[15] Of this total, KenGen's installed capacity amounted to 72 percent; IPPs made up the majority of the balance. Table 6.1 highlights KenGen's total capacity as of April 2015.

The recent shift to a mix of publicly financed energy supply has increased reliance on geothermal energy and encouraged the emergence of wind energy. Geothermal energy increased from 12 percent of KenGen's total installed capacity in 2006 to 32 percent as of April 2015. The share of installed wind capacity, though relatively small (at 1.6 percent), has increased substantially from its base and is expected to increase further after additions at Meru. The share of traditional thermal gas and diesel has become less significant (at 15 percent) as it is displaced by geothermal.

Table 6.1 KenGen's Installed Generation Capacity: Kenya, as of April 2015

Technology	*% of capacity*	*Project*	*Capacity (MW)*	*PPA (years)*	*COD*[a]
Major hydros	48.93	Various	765.5	20	2008
Medium hydro	1.28	Sang'oro	20	20	2012
Small hydro	0.75	Various	11.7	15	2009
Isolated thermal	0.35	Lamu	2	15	2009
		Garissa	3.4	15	2009
Small wind	0.35	Ngong old	0.35	15	2009
		Ngong I Phase I	5.1	15	2009
Wind	1.30	Ngong I Phase II	20.4	20	2015
Geothermal	32.40	Olkaria I (Units 1, 2, and 3)	45	4	2013
		Olkaria II	105	20	2008
		Olkaria IV	140	25	2014
		Olkaria I (Units 4 and 5)	140	25	2014
		Well head 37	2.5	15	2012
		Well head 43	2	15	2012
		Well head 1	20	15	2012
		Well head 2	20	15	2012
		Well head 3	30	15	2012
		Eburru	2.44	20	2012
Thermal/diesel	11.19	Kipevu Diesel Power I	60	15	2008
		Kipevu Diesel Power III	115	20	2011
Thermal/gas	3.45	Embakasi Gas Turbines	54	3	2013
Total	**100.00**		**1,564.39**		

Source: Based on data received from the Kenya Power and Lighting Company, 2015.
Note: KenGen = Kenya Electricity Generating Company; MW = megawatt; PPA = power purchase agreement.
a. COD refers to the commercial operation date of the latest PPAs, as some plants, especially hydropower, have been redeveloped, and Olkaria I (Unit 1) has been in operation since 1981.

IPPs together account for approximately 26 percent of the installed capacity in Kenya (or 565 MW)—see table 6.2.[16] Most capacity is supplied by diesel generators (78 percent), followed by a geothermal installation (OrPower4, 18 percent) and a cogeneration installation (5 percent). The percentage of IPP capacity has grown considerably since 2005, when IPPs accounted for only 12 percent of installed capacity. Sponsors have been diverse, as will be discussed in the following sections, and technology types are increasingly varied.

Total installed generation capacity also includes emergency power projects (EPPs), which today account for only 30 MW (2015) or less than 1 percent of the total. Dependence on EPPs has fluctuated considerably over the past decade; their peak was in 2008 and 2009, when EPP installed capacity amounted to 11 percent of the total.

Power Sector Performance

How have KenGen and IPPs measured up in terms of the actual electricity produced and its availability, price, and capacity factors? What does a comparison of public and privately procured plants reveal? Can it offer lessons for future procurement processes?

Table 6.2 Independent Power Projects, Installed Generation Capacity: Kenya, as of April 2015

Technology	*% of capacity*	*Project*	*Capacity (MW)*	*PPA (years)*	*COD*
MSD/HFO	9.99	Iberafrica Power Company (plant 1)	56.346	7 + 15	2004[a]
MSD/HFO	9.30	Iberafrica Power Company (plant 2)	52.5	25	2009
MSD/HFO	13.11	Tsavo Power Company Ltd.	74	20	2001
MSD/HFO	15.67	Rabai Power	88.4	20	2010
MSD/HFO	15.42	Thika Power (Melec)	87	20	2014
MSD/HFO	14.18	Gulf Power	80	20	2014
Geothermal	17.72	OrPower4 Inc.	48	20	2009
Geothermal		OrPower4 Inc.	36	20	2013
Geothermal		OrPower4 Inc.	16	20	2014
Cogeneration	4.61	Mumias Sugar Company Ltd.	26	10	2010
Total	**100.00**		**564.246**		

Source: Based on data received from the Kenya Power and Lighting Company, May/June 2015.
Note: Triumph Power, an 83 MW MSD, was expected to reach COD by 2Q2015. Excluded from this table are the small independent hydropower plants Imenti Tea Factory and Gikira, which amount to 0.75 MW and 0.514 MW, respectively. COD = commercial operation date; MSD/HFO = medium-speed diesel/heavy fuel oil; MW = megawatt; PPA = power purchase agreement.
a. Fifteen-year PPA starting in 2004.

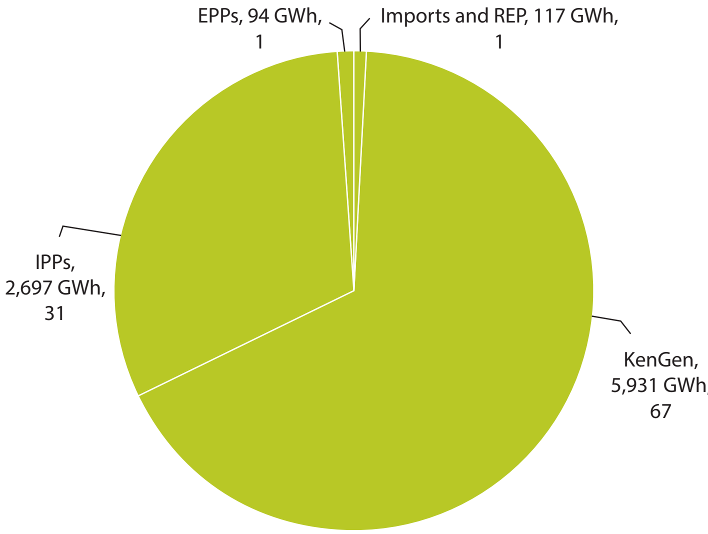
Electric Power Production

In the period July 2013–June 2014, the latest for which complete data are available, KenGen produced 5,931 gigawatt-hours (GWh) of electricity, or 67 percent of the total (of which approximately 67 percent was KenGen hydropower installations, and the balance was largely geothermal, accounting for 19 percent). This was followed by IPPs at 31 percent, EPPs at 1 percent, and a total of 1 percent contributed by imports and the government's Rural Electrification Programme (REP), as illustrated in figure 6.2. This represents a change from 2012–13, when KenGen's portion amounted to 74 percent and IPPs to only 22 percent. Thika Power has come online and production has been ramped up at Rabai as well.

Assessing IPPs individually reveals an important piece of evidence. Iberafrica, with the second-largest installed capacity, is providing only 20 percent of generation (a significant drop from previous years). Instead, OrPower4 is contributing the largest piece of the production pie, followed by Rabai. Tsavo's portion is relatively small due to merit-order dispatch and transmission constraints. An expansion of the Mombasa-Nairobi electricity transmission line has been delayed, limiting the further evacuation of power, which has had an impact on many plants (Obiero 2015), though not on the Nairobi-based Iberafrica IPP. (See figure 6.3 for the contribution of the various IPPs.)

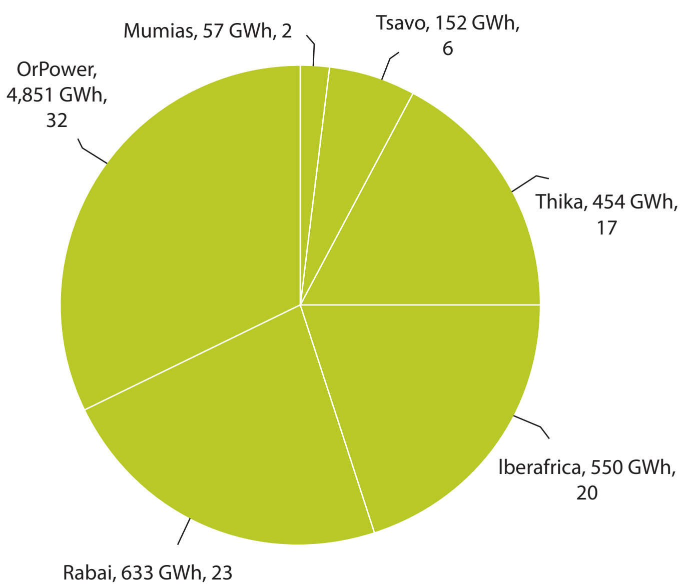
At the end of 2014, a significant development occurred: for the first time in Kenya's history, geothermal production (public and private combined) surpassed hydropower (see table 6.3), with important ramifications for supply going forward.

Figure 6.2 Electricity Production, by Firm/Organization Type: Kenya, 2013–14
percent



Source: Authors' compilation, based on KPLC 2014.
Note: EPP = emergency power plant; GWh = gigawatt-hour; IPP = independent power project; KenGen = Kenya Electricity Generating Company; REP = Rural Electrification Programme.

Figure 6.3 Electricity Production of Six Independent Power Projects: Kenya, 2013–14
percent



Source: Authors' compilation, based on KPLC 2014.
Note: GWh = gigawatt-hour.

Table 6.3 Total Production, by Technology/Fuel: Kenya, 2013 and 2014
percent

Technology/fuel	*2013*	*2014*
Biomass	0	0
Wind	0	> 0 < 1
Thermal	37	10
Hydro	46	38
Geothermal	14	51

Source: Based on data received from KenGen (Kenya Electricity Generating Company), June 2015.

Availability

Kenya offers an interesting opportunity to directly compare the performance of the state-owned power plant with that of IPPs using similar technology. Plant availability is arguably the best indicator of that performance (see table 6.4 for a comparison of the actual and targeted availability of private and public plants using similar technology).

With the exception of Kipevu I, all diesel projects, public and IPP alike, have met their availability target; however, IPPs with diesel projects have outperformed their public sector equivalents. The same may be said of geothermal plants (see table 6.5), although the technology is not comparable: KenGen plants are flash while OrPower4 uses binary technology (expected to offer better availability).

KenGen's Olkaria I (Units 1, 2, and 3) was available only 68.3 percent of the time in 2014—far below its target and the performance of its private sector counterparts. This low share may in part be due to age: Olkaria I's units are 30–33 years old (dating from 1981–85). Also, it should be noted that KenGen plants must follow public procurement procedures; delayed payment processes do not allow fast access to critical parts in the event of an emergency, an issue that may affect overall performance.

Table 6.4 Actual and Targeted Availability of Public and Private Diesel Plants: Kenya, April 2015
percent

Plant	*Ownership*	*Actual availability*	*Targeted availability*
Tsavo Power Company Ltd.	IPP	97.21	85.00
Thika Power (Melec)	IPP	95.72	85.00
Kipevu Diesel Power III	KenGen	94.58	85.00
Iberafrica Power Company (plant 2)	IPP	93.92	85.00
Gulf Power	IPP	93.60	85.00
Rabai Power	IPP	91.65	85.00
Iberafrica Power Company (plant 1)	IPP	87.95	85.00
Kipevu Diesel Power I	KenGen	66.95	85.00

Source: Based on data received from the Kenya Power and Lighting Company, May/June 2015.
Note: IPP = independent power project; KenGen = Kenya Electricity Generating Company.

Table 6.5 Actual and Targeted Availability of Public and Private Geothermal Plants: Kenya, April 2015
percent

Project	*Ownership*	*Actual availability*	*Targeted availability*
OrPower4 (16 MW)	IPP	99.79	96.00
OrPower4 (48 MW)	IPP	99.17	96.00
OrPower4 (36 MW)	IPP	97.82	96.00
Olkaria IV	KenGen	96.45	94.00
Olkaria I (Units 4 and 5)	KenGen	95.15	94.00
Olkaria II	KenGen	84.30	94.00

Source: Based on data received from the Kenya Power and Lighting Company, May/June 2015.
Note: OrPower4 represents only one project, of which different units are recorded in the table.
IPP = independent power project; KenGen = Kenya Electricity Generating Company; MW = megawatts.

Electricity Prices

While data on plant availability demonstrate the technical superiority of IPPs over KenGen, electricity prices offer a more nuanced picture. It should be noted at the outset that a direct comparison between KenGen and IPPs is not possible, since they pay different costs for their capital. While KenGen has raised private capital via bond issues, it has also accessed loans from development finance institutions (DFIs). See table 6.6 for a comparison of KenGen and IPP (and EPP) diesel plants; the values listed represent the sum of energy, fuel, capacity charge, and forex adjustment.

The two KenGen plants are largely more competitive than IPPs; however, Rabai IPP distinguishes itself as the cheapest of all. Apart from the cost of capital, there are important additional qualifiers related to specific technologies and location that explain some of the cost discrepancies. Rabai has a heat-recovery system, which improves efficiency and is located close to the port of Mombasa (and the plant's fuel source). But this system explains part of the cost difference when Rabai is compared with the Tsavo IPP and KenGen's Kipevu I and Kipevu III plants, also located in Mombasa. Thika Power and Gulf IPP have heat-recovery systems as well, but these plants are located up-country, near Nairobi, and must pay the additional fuel cost for transportation from Mombasa (about 500 kilometers, km). Iberafrica, located in Nairobi, must also pay an additional cost, and has technology similar to that of KenGen's plants and the Tsavo IPP.

Among geothermal plants, most of the publicly owned KenGen plants are relatively more competitive; Olkaria II is a notable exception, having proved more costly than OrPower4 (table 6.7).

In sum, though KenGen remains the dominant producer, IPPs contribute an important share: 30 percent of production in 2013–14. Meanwhile, supply (from private and public sources alike) is changing amid increased reliance on geothermal power. The technical performance of IPPs, as gauged by actual and target plant availability, appears to be superior to that of publicly owned plants (for both diesel and geothermal). An HFO IPP—Rabai—is cheaper than the KenGen

Table 6.6 Electricity Prices of Public and Private Diesel Plants: Kenya, June 2015

Project	*Technology*	*Location*	*Ownership*	*Price (K Sh/kWh)*	*Price (US$/kWh[b])*
Iberafrica Power Company (plant 1)	MSD/HFO	Nairobi	IPP	22.82	0.25
Iberafrica Power Company (plant 2)	MSD/HFO	Nairobi	IPP	22.61	0.25
Temporary power plants (Aggreko)	MSD/HFO	Various	EPP	20.99	0.23
Gulf Power	MSD/HFO[a]	Near Nairobi	IPP	20.43	0.22
Thika Power (Melec)	MSD/HFO[a]	Near Nairobi	IPP	19.86	0.22
Tsavo Power Company Ltd.	MSD/HFO	Mombasa	IPP	19.84	0.22
Kipevu Diesel Power I	MSD/HFO	Mombasa	KenGen	17.70	0.19
Kipevu Diesel Power III	MSD/HFO	Mombasa	KenGen	15.86	0.17
Rabai Power	MSD/HFO[a]	Mombasa	IPP	12.74	0.14

Source: Based on data received from the Kenya Power and Lighting Company, May/June 2015.
Note: EPP = emergency power project; HFO = heavy fuel oil; IPP = independent power project; KenGen = Kenya Electricity Generating Company; K Sh = Kenya shilling; kWh = kilowatt-hour; MSD = medium-speed diesel.
a. Gulf, Thika, and Rabai have heat-recovery systems and thus greater efficiency rates.
b. Assuming the average conversion rate in April 2015 of $1 = K Sh 91.57.

Table 6.7 Prices among Public and Private Geothermal Plants: Kenya, June 2015

Project	*Ownership*	*Price (K Sh/kWh)*	*Price (USc/kWh)*
Olkaria II	KenGen	12.97	0.14
OrPower4	IPP	8.99	0.10
Olkaria IV	KenGen	6.14	0.07
Olkaria I (Units 4 and 5)	KenGen	5.91	0.06
Olkaria I (Units 1, 2, and 3)	KenGen	3.09	0.03

Source: Based on data received from the Kenya Power and Lighting Company, May/June 2015.
Note: IPP = independent power project; KenGen = Kenya Electricity Generating Company; K Sh = Kenya shilling; kWh = kilowatt-hour; USc = U.S. cent.

plants at the same site. Meanwhile, the costs of KenGen geothermal plants appear to be more competitive than those of IPPs, but the comparison is hampered by differences in funding sources, technologies, locations, and the availability of spare parts.

Independent Power Projects, Emergency Power Projects, and Publicly Sponsored Power Plants

Private participation in generation is not new to Kenya; what is new, however, is the anticipated scale. Until recently, private power played a subsidiary role (as of 2013–14, after almost two decades of development, IPPs accounted for 26 percent of installed generation and 31 percent of production). But it is expected to play the lead. Of the near-term capacity envisioned in the 5,000+ MW program, the majority (70 percent) would be through the private sector (with KenGen and GDC developing the balance, or 30 percent).[17]

In this context, it is instructive to review how private and public plants have been procured in parallel over the past two decades, and how this might inform the next series of procurements.[18]

First Wave: The Stopgap Independent Power Projects, c. 1996

The first wave of privately financed power, dating to 1996,[19] involved the procurement of two diesel IPPs: Westmont (46 MW) was sponsored by a Malaysian firm, and Iberafrica (44 MW) represented a partnership between Union Fenosa (Spain, 80 percent) and the KPLC Pension Fund (Kenya, 20 percent). While no international competitive bidding was conducted, there was competitive bidding from a restricted list of bidders drawn from a longer list of bidders that had shown interest in the Kipevu II project, discussed shortly. With a tenure of seven years, longer than that of most EPPs, these first two IPPs were considered stopgap measures addressing drought and the delayed construction of projects envisioned in the LCPDP—and an ensuing power crisis. Westmont would not renew its contract in 2004 after it failed to agree on tariff levels. Iberafrica, meanwhile, renewed its contract (albeit on more favorable terms to country stakeholders) and increased capacity (first by 12 MW, then an additional 52 MW) to reach 108.5 MW in 2015.

Second Wave and a KenGen Comparison, c. 1997–99

Prior to the stopgap IPPs, all power projects had been implemented by the public sector through the concessionary funding of bilateral and multilateral funding agencies, including the World Bank (International Development Association, IDA). Amid a move to reform and liberalize the sector, and a corresponding lack of funding, the private sector was invited to develop generation projects. In 1996, the KPLC resumed a procurement process (initiated in 1995, prior to the stopgap IPPs), following an international competitive bid (ICB), for two projects—Olkaria III and Kipevu II—which came to be known as OrPower4 (varying MW[20]/geothermal) and Tsavo (74 MW/diesel), respectively. OrPower4 was exclusively developed by Ormat (Israel/USA, 100 percent), while Tsavo represented a consortium of investors: Duke Energy and Industrial Promotion Services (IPS) (jointly 49.9 percent), Commonwealth Development Corporation (CDC)/Globeleq (United Kingdom, 30 percent), Wartsila (Finland, 15 percent), and the International Finance Corporation (IFC, 5 percent). Although both projects were procured via ICB, it is noteworthy that only three bids were received for the Tsavo plant and two for what would become OrPower4.[21]

During this same period (1997–99), KenGen would also develop Kipevu I (a 75 MW diesel-fired plan). Despite tightening purse strings and a shift toward privately funded generation, funding was secured from the Japan International Cooperation Agency (JICA, then the Japan Bank for International Cooperation [JBIC]) for this project. An ICB for engineering, procurement, and construction (EPC) was conducted for KenGen's Kipevu I, as for OrPower4 and

Tsavo—the standard for all public and private plants, unless procured through feed-in tariffs (FiTs) (discussed in chapter 4) or under other conditions prescribed by procurement laws.

The Development of Emergency Power Projects, c. 2000–10

In the years that followed, amid worsening hydrological conditions, the MoEP directly arranged EPPs. There was limited competitive bidding: that is, bids were invited from a short list of known international EPP providers. Ultimately, contracts with three international EPPs (Aggreko, Cummins, and Deutz) for a combined 105 MW would be sealed for rental capacity between 2000 and 2001. In 2006, Aggreko would be called upon, again, to provide 80 MW, and in 2007, its contract would be extended and increased to 100 MW, and then 150 MW. By 2009, Aggreko had 290 MW of emergency power. By mid-2010, however, the requirement was reduced (to only 60 MW), with a plan to retire all such emergency power by November. The reemergence of drought in the latter part of 2010 prompted a reconsideration of that plan, and the installation of 60 MW at Muhoroni. In 2012, there were 120 MW of EPPs; this has since been reduced to a mere 30 MW (KPLC 2006: 68; 2007: 98; 2008: 104; 2009: 100; 2010: 104; 2011: 115; 2012).

A Brief Hiatus and Complementary Developments, c. 2004–09

Although no new IPP procurements were conducted for nearly a decade, additional capacity, as alluded to earlier, would be added for Iberafrica and OrPower. Iberafrica renegotiated the terms of its tariff and a second power purchase agreement (PPA) starting in 2004. The next IPP, conducted via an ICB in 2007, would be Rabai (90 MW diesel). Only four bids were received, although more than for Tsavo and OrPower4. Following the award, legal challenges led to an eight-month delay;[22] further challenges involved the changing political climate in Kenya in 2008 (and associated postelection violence) as well as the meltdown of global financial markets. Still, the project closed in 2008 and came onstream in 2009. Project equity stakeholders included Aldwych (United Kingdom, 34.5 percent), Burmeister & Wain (Danish, but owned by Mitsui of Japan, 25.5 percent), the Netherlands Development Finance Company (FMO) (Netherlands, 20 percent), and the Danish Investment Fund for Developing Countries (IFU) (Danish bilateral lender, 20 percent).

During this period, KenGen also made advances on Olkaria II, a geothermal installation. In 2003–04, the first 70 MW came online, followed by the balance in 2009, resulting in a total of 105 MW.[23] This complemented KenGen's existing geothermal capacity (Olkaria I, 3 × 15 MW units, which had been phased in over the 1980s). At the same time, KenGen was tasked with the Kipevu III extension of 120 MW (diesel), which came online in 2011. This too followed an ICB for its EPC.

In each of these instances, public and private procurements were considered to be complementary, not competitive. Decisions were made by the government in consultation with the KPLC, the World Bank, and other sector donors. To mobilize adequate funding for capacity expansion, those projects considered likely to attract private sector funding were offered to IPPs, all via ICB, excluding the first round of stopgap IPPs. Procurement, with the KPLC at the helm, has widely been considered to be positive, specifically with regard to running effective competitive bids for thermal capacity.

A Renewed Push from the Private Sector, c. 2010

Finally, in 2010, the KPLC began a series of procurements. The first related to three diesel generators (Kitengela I, Kitengela II, and Nairobi, today commonly known as Triumph,[24] Gulf,[25] and Thika[26]) of approximately 80 MW each via an ICB. A total of 31 expressions of interest were received, followed by 23 prequalifying bids, for all three plants. Subsequently five bids were received for Kitengela I, five for Kitengela II, and then two for Nairobi, which was retendered.[27] The second procurement related to a 52 MW extension at OrPower4.

There was considerable competition for the three diesel generators. This shows how much the sector has evolved since the late 1990s, when the first ICBs resulted in Tsavo and OrPower4. It is also noteworthy that, for OrPower4, the initial procurement (of 13 MW) was done using ICB; however, since the late 1990s, the plant has added a further 97 MW in capacity (in three different phases), none of them with a competitive bid process. OrPower4 pricing has become a benchmark for private geothermal in Kenya and across Sub-Saharan Africa, but there has been no direct private competition to this benchmark since 1997.

Emerging Renewable Technologies in Kenya

Although Kenya has a history of small public geothermal investments and IPPs dating to the 1980s and late 1990s, respectively, there has been limited public and private renewable activity besides publicly funded hydropower. Kenya's nascent wind and new geothermal activity marks a departure from earlier trends, and is the focus of the following section.

Feed-in Tariffs and Support for Renewables

Specific interventions to accelerate renewables in Kenya date to 2008, with the FiT policy. The first iteration of this policy did not attract investors, and tariffs were subsequently reviewed in January 2010 (Climatescope 2014). A second FiT regime was introduced in 2012. The parameters were as follows: wind projects' capacity was to reach 50 MW, and an earlier applicable tariff of USc 12/kilowatt-hour (kWh), fixed over the term of the PPA, was capped at the weighted average long-run marginal cost of generation. The current tariff is U.S. cents (USc) 11/kWh, 12 percent of which is scalable according to the U.S. dollar consumer price index (CPI). A number of renewable projects have been approved, namely, the Kinangop Wind Farm (60 MW), Kipeto Wind (100 MW), Kwale Sugar Mill (18 MW), and several small projects in the range of 0.5 to 2.0 MW.[28] It is important to note that these projects do not involve a specific payment security instrument, such as a letter of credit from the KPLC. They do, however, have a letter of project support from the government, which, while not a guarantee, carries weight.

Kinangop, Kenya's first FiT project, developed by Aeolus Wind Kenya and now funded primarily by the African Infrastructure Investment Fund 2 (AIIF2), Norfund, and Stanbic, reached financial close in 2013. During the development stage, Aeolus reached agreements with landowners, but in the ensuing months, more landowners in the area made additional claims. In February 2015, there was a series of protests, and an altercation between the community and police resulted in one civilian death. The Kenyan government made attempts to resolve the issues involved; in the meantime, the EPC contractor, which had been restricted from the site, exercised its right to declare force majeure. As of the third quarter of 2015, the project had been halted.

Donors and financiers such as Power Africa, the World Bank, Agence Française de Développement (AFD), the African Development Bank (AfDB), the Kreditanstalt für Wiederaufbau (KfW, German development bank), and the European Investment Bank (EIB), among others, are increasingly providing support and advisory services to help such projects reach financial close. Looking at the broader electricity landscape, however, an increase in wind capacity may make poor economic sense for Kenya. While less costly than imported thermal power, wind may substantially increase the price of electricity to users (displacing low-cost geothermal and hydropower-generated energy, for variable power at approximately USc 10–12/kWh), and potentially increase grid instability.

Finally, it is important to note that while Kenya's development partners have programs targeting the promotion of renewables through private sector participation, Kenya itself offers no special incentives for renewables, other than the FiTs. As has been noted, coal and, until recently, LNG formed the bulk of proposed new capacity. The government's focus has been, first and foremost, to increase the supply of reliable and competitive power, primarily through indigenous resources. Renewables—most notably geothermal and (soon) wind power, and to a lesser extent solar power—are part of the equation but do not enjoy favored status.

Directly Negotiated Renewable Projects

Departing from the well-defined procurement process for thermal IPPs—with the KPLC at the helm and the REFiT process outlined earlier—in 2011, a PPA was negotiated with the Lake Turkana Wind Project (LTWP). The LTWP was not part of the LCPDP of 2009. Instead, the project was initiated as an unsolicited bid directly with the government of Kenya at a time when the government was actively promoting renewable energy, but before it formulated the FiT policy and the later Public Private Partnership Act. Importantly, the ERC was not involved at the time of project initiation. Given the absence of a valid comparator—that is, a private wind project procured via an ICB—it is difficult to assess the LTWP's outcomes and cost-effectiveness. The next large wind project, Kinangop Wind Farm, is a FiT, not an ICB. The tariff negotiated for the LTWP under the PPA has a base rate of €c 7.52/kWh for up to 1,684 GWh and €c 3.76/kWh for any additional power, with 14 percent of the base tariff scalable, and linked to the euro area CPI. This appears to be competitive with the present FiT wind tariff of USc 11/kWh. However, the capacity factor assumed for the LTWP is significantly higher than that for the FiTs, which makes the comparison less accurate.[29] Regardless, both Turkana and Kenya FiTs are expensive when compared with recent competitively bid wind FiTs, including the South African Renewable Energy Independent Power Project Procurement Programme (REIPPPP), at USc 4.7/kWh.

Geothermal Development

Following the unbundling of the KPLC in 1997, KenGen assumed ownership of Kenya's public generation facilities. Thirty percent of the entity would go on to be privatized following the power sector reform strategy, as outlined earlier. Among the next significant developments was the creation of the GDC in 2008 (operational in 2009). The GDC, a 100 percent government-owned entity, was given all mining rights for geothermal steam in the country with the exception of those held by KenGen and Ormat (at Olkaria), as well as those that had already been concessioned by the government (Longonot, Akiira, and Suswa).[30] The company was expected to handle the most risky part of geothermal activity (namely, exploration, appraisal, and production drilling) and thereby remove much risk from project development. It was also expected that the GDC would then sell steam to IPPs and KenGen.[31]

The GDC and geothermal activities in Kenya have been supported by a diverse array of multilateral, bilateral, and regional development partners, most notably the IDA, EIB, AFD, AfDB, and JICA.[32] The GDC should be increasingly funded by revenue generated from steam sales to IPPs and KenGen. However, this hinges upon the success of the geothermal power projects fueled by steam from the GDC, as well as a steam-pricing strategy that is attractive to investors. As the GDC undertakes risky geothermal exploration on behalf of the government, some form of subsidy may continue to be required depending on the nature and extent of the exploration activities.

Despite a multimillion-dollar investment in the GDC and pressure to meet the power supply targets associated with Kenya's 5,000+ MW program (by providing steam to IPPs and KenGen), since its inception the company has been able to source only limited steam. Between 2010 and 2014, three expressions of interest (EoIs) were invited for 400 MW (revised to 800 MW, phase II at Menengai) and 800 MW (at Bogoria-Silali), as well as for 300 MW at Suswa. In 2014, the GDC finally managed to award three contracts of 35 MW each, for a total of 105 MW, at the Menengai field.

It is important to note the large gap between what was originally invited by the GDC—namely, 1,900 MW of geothermal activity (between 2010 and 2014)—and the 105 MW that is expected to reach financial close. While the initial capacity targets may have been inflated, other issues specifically related to the GDC and its business model may have hampered the procurement process as well. First, the availability of the requisite steam supply was uncertain.

Second, no government guarantee or support was initially extended for the projects, which may have detracted from their viability since the GDC itself has no equity. All the funds the GDC invested have come from the government of Kenya and the soft loans of development partners.[33] The 105 MW Menengai project has since received the backing of the AfDB, which provided $12.7 million in partial risk guarantees (PRGs). This should help secure financial backing for three projects sponsored, respectively, by the Sosian Menengai Geothermal Power Ltd., Quantum Power East Africa (QPEA) GT Menengai Ltd., and OrPower (22 Ltd.) (AfDB 2014; Ormat 2014). QPEA GT and Sosian are Kenyan firms and their indicative price is USc 8.5/kWh (inclusive of the steam price of USc 3.0/kWh). The GDC remains unable to stand on its own.

Meanwhile, steps forward are still being made. The first target of new capacity additions set under the 5,000+ MW program (see annex 6A)—namely, 176 MW by October 2014—has been met, albeit not by the GDC. By end-2014, KenGen had connected the entire 280 MW from Olkaria I and IV to the national grid, which led geothermal to surpass hydropower as a source of electricity. Plans are now taking shape for an additional 350 MW by 2017 (Herbling 2014; KenGen 2014a). While the GDC drilled some wells on behalf of the government, it is not expected to be active in the 280 MW project in Olkaria going forward. The GDC and KenGen are, however, required by the MoEP to enter into an agreement under which the GDC will receive royalties for steam from KenGen (USc 3/kWh).

Although the GDC and KenGen may not compete at Olkaria, the clear designation and development of projects, along with appropriate safeguards, has yet to be established. One experienced stakeholder commented, "at present, I think all real new geothermal developments will probably be done by KenGen depending on their credit capacity. [There is little] room for IPPs. The business conditions that allowed the successful development of OrPower4, do not exist presently in Kenya" (March 20, 2015).

Independent Power Plants: Risk Mitigation Mechanisms and Other Contingencies

Of the stopgap IPPs, Westmont and Iberafrica, the first involved an escrow account and the second an advance payment cash deposit.[34] Thereafter, in the initial phase of IPP development (1997–98), the KPLC was required to provide two-tier payment securities in the form of a standby letter of credit (SBLC) and escrow accounts (ring-fencing part of the coastal area receivables as a payment guarantee). This double security was requested because of Kenya's poor credit rating and the KPLC's weak balance sheet[35] (a weakness exacerbated by the severe drought of 1999–2001). The ERB's (now the ERC's) failure to take remedial action on the KPLC's retail tariffs (vs. KenGen's bulk tariff) caused the company to incur financial losses over four consecutive fiscal years.

The two-tier payment security arrangement was not applied in subsequent IPP projects for the following reasons: (1) the KPLC's return from the sunk escrow fund was not optimized; (2) the KPLC incurred the additional costs of a double security; and (3) there were additional administrative costs, including for staff dedicated to ring-fencing the revenues and ensuring that the billing system could collect captive receivables. Subsequently, for the three medium-speed diesel generators procured from 2010, the KPLC provided an IDA-backed PRG with a government letter of support for an off-taker termination default. According to stakeholders consulted at Thika Power: "I think [the World Bank] role was essential—these projects [referring to all 3 diesel generators] would have taken ages to close without a PRG" (personal communication, May 7, 2014).

In the case of the LTWP, a PRG of €20 million was extended by the AfDB for the timely completion of the transmission line. This also covered the off-taker risk of the nonpayment of monthly invoices, and the risk of the PPA's termination (AfDB 2013). Meanwhile, a payment security for the LTWP was to be provided via an escrow account, raised via a tariff increase starting in 2013.

For Menengai Phase I (3 × 35 MW geothermal projects), initially the only security was a government letter of support in the case of termination due to default by the KPLC/GDC. The idea of not providing liquid security was to remove the contingent liability of the SBLC. In fact, the KPLC intended to use the available SBLC capacity to support distribution expansion projects. Also, the Kenyan IPP market was believed to be sufficiently mature. However, given the GDC's financial fragility, this security proved to be insufficient. Since, the project has necessitated the backing of the AfDB, in the form of a PRG covering the KPLC payment default as well as a default stemming from the failure of the GDC to supply enough steam. Going forward, PRGs appear to be the most likely form of risk mitigation.

There are no guarantees for FiTs, and this may be an area for further improvement. Most prospective investors (excluding FiTs) appear to be satisfied with the KPLC's track record of timely payments of IPP invoices, and the KPLC has never defaulted. There is, however, concern about how the KPLC's creditworthiness will be affected by the large surplus capacity that may result from the recently signed PPAs, including some under construction (which made up part of the 5,000+ MW program), as well as what may happen as a wholesale market takes shape. In some of the PPAs presently under negotiation, the KPLC has introduced a clause moving the market risk from the KPLC to the government (through a letter of support) and another stating that, should there be a wholesale market, the parties can consult with a view to opting out of the PPA in a mutually acceptable manner.

The Public Sector Making Way for the Private Sector, or a Contested Playing Field?

In the Power Sector Medium Term Plan (2014–18), it was estimated that KenGen would have a total of 800 MW in geothermal capacity by December 2018, thereby tripling its capacity (ERC 2014c). This could potentially squeeze out private investment from the sector, particularly if KenGen projects are supported by concessionary finance. Plans for new wind installations, including a feasibility study for a 150 MW wind farm, Marsabit Wind, and the 50 MW Isiolo are also under way (KenGen 2014b).[36] Additionally, local coal deposits are being explored and assessed. KenGen identified the 600 MW Kilifi project for completion in 2016, though momentum on this project has slowed and it is presently still in exploratory drilling.

Furthermore, despite murmurs that the country's (large) hydropower potential has been exhausted, the government has indicated that it will continue to develop its hydropower resources—it "estimate[s] that the undeveloped hydroelectric power potential of economic significance is 1,449 MW out of which 1,249 MW is for projects of above 30 MW" (MoEP 2014b: 46).[37] Between 2011 and 2014, KenGen noted 53 MW in new hydropower capacity, though this included the upgrading of existing capacity. Among ongoing and new projects, hydropower facilities are notably absent. However, the MoEP has indicated its intent to finance prefeasibility studies for the identification of potential hydropower sites, and 290 MW of new (multipurpose) hydropower projects have been identified as public-private partnerships (PPPs) by the Ministry of Environment, Water, and Natural Resources.

Overall, there are great prospects for increasing private participation in the generation sector. Nonetheless, publicly funded generation is not about to stop any time soon. KenGen does not show any sign of slowing its activities and remains, without question, the dominant player in the generation sector.

As highlighted at the outset of this case study, instead of lack of power, there is a concern about surplus power in Kenya. IPPs, which are required contractually to retain at least three months' equivalent of fuel supplies to avoid stockouts, have been laden with stock, which has become an increasing liability amid falling oil prices. IPPs have petitioned the regulator to review relevant policies and prices, given the changing circumstances (Situma 2015).

Conclusions and Recommendations

For two decades private and public power projects in Kenya have been developed in parallel. Private developers have been critical in mobilizing funding to meet the nation's demand for electricity, and have complemented publicly owned projects.

Kenya's power-planning process has been dynamic. The LCPDPs have been periodically updated in collaboration with international consultants under the direction of the regulator and involving all relevant stakeholders.

Although the first (stopgap) IPPs were procured through limited competition, there has since been a strong track record of international competitive bidding. From the late 1990s, new build opportunities have been allocated to either the national power generation company, KenGen, or to private IPPs, and procured via ICBs run by the national transmission/distribution company, the KPLC.

Separated from KenGen, and housing the system operator, the KPLC does not face any generation investment conflicts and can procure new power in a fair, transparent, and competitive fashion. The KPLC has built up considerable internal procurement and contracting capabilities and has been able to run timely and effective procurement processes. While the first ICBs that cemented deals with Tsavo and OrPower4 attracted only limited competition (three and two bidders, respectively), ICBs conducted for the three recent diesel generators resulted in nine bidders for the Thika plant alone.

There are well-recognized links between the transparency of procurement processes, price outcomes, and the sustainability of projects. Prices have generally declined since the first IPPs were procured, which signals the merits of private power and increased competition. Thermal IPPs demonstrate superior technical performance relative to KenGen's plants with similar technologies. Pricewise, KenGen's projects appear to be more competitive, though the least expensive thermal is an IPP. A direct comparison between public projects (KenGen's plants) and private projects (IPPs) is clouded by the fact that their respective costs of capital have been different. While KenGen has raised private capital via bond issues, it has also benefitted from concessionary funds. Location and specific technology types also influence any comparison.

More recently, the planning process has not always been based on solid independent technical analysis; the government's demand estimates have tended to be unrealistically high. Also, a number of generation projects have been procured without following a competitive process, and without a thorough technical and financial analysis to determine if the plants' integration and system requirements are in line with least-cost planning standards. In particular, the landscape for new build opportunities has been affected by the involvement of the GDC, which has been only minimally successful in attracting investment, and whose model remains unsustainable. Further complications have arisen due to noncompetitively bid wind projects, which have proven to be much more expensive than comparable projects that involved competitive bidding, notably in South Africa. Meanwhile, KenGen has asserted itself as the dominant player in geothermal activity and is on track to continue as such, possibly squeezing out private investment. Based on these findings, the following recommendations are offered:

- Overly ambitious demand assumptions that have been directed by the government should be tempered, and the planning process allowed to follow its due course involving the relevant, empowered agencies.
- The current generation plan might be revised to reset activities on the basis of well-grounded macroeconomic and technical assumptions, including the issue of proper assessments of system integration challenges for wind and solar capacity.
- To ensure coherent planning, procurement, and contracting, it is necessary to continue building relevant capacity in key institutions, including the MoEP, PPP Unit, ERC, and GDC.

- KenGen could offer greater disclosure of its capacity charges, reflecting the cost of capital, so that a more accurate comparison of electricity prices may be analyzed and made public.
- If the GDC is to operate effectively in the market as a provider of steam to IPPs, then the GDC should be capitalized and/or a guarantee program should be put in place to reduce any uncertainty surrounding this dispatch by addressing the current imbalance of supply and demand.
- Provided that there is a viable steam provider, adequate space should be allocated to the IPPs and KenGen to minimize the crowding out of the private sector.
- The FiT regime should be revisited with private and public stakeholders alike to determine whether it is the best way to engage renewable development or whether international competitive bidding processes, following South Africa's example, ultimately make more sense.
- The creditworthiness of the off-taker (KPLC) is critical for the successful procurement of IPPs and other power capacity; efforts to improve it should continue.
- Given the outcomes of the recent renewable projects awarded without competition, Kenya should potentially explore ICBs for future solar projects, particularly in remote areas.
- Finally, addressing transmission constraints and integration issues to ensure that all the power generated is actually delivered remains an area in need of improvement.

In summary, Kenya has demonstrated the clear advantages of competitive bidding for thermal plants, and also the cost advantages of renewable energy, particularly geothermal power. After two decades of experience, the key remains in the careful implementation of IPPs, from planning to competitive procurement to effective contracting.

Annex 6A The Initial 5,000+ MW Program: An Overview of Targets and Timelines

According to industry experts, massive capacity additions do not make sense unless they are matched by demand. The ideal supply profile should be 15–20 percent more than demand. The inclusion of massive coal and liquefied natural gas (LNG) projects has the potential to distort planning decisions.

The projects noted in table 6A.1 involve an ambitious interim LNG project with potential imports from Qatar (Senelwa 2014). The tender for the LNG project was not, however, awarded because none of the bidders agreed to the timelines required in the request for proposal. The project has since been shelved, also partly due to the discovery of natural gas in Wajir (in northeastern Kenya).

Table 6A.1 Cumulative Installed Capacity, 5,000+ MW Program, Kenya

No. of months from start of project	*0*[a]	*6*	*12*	*18*	*24*	*30*	*36*	*40*
Technology	*Cumulative installed capacity (MW)*							
Hydro	770	794	794	794	794	794	794	794
Thermal	622	709	782	782	782	432	432	432
Geothermal	241	331	507	697	747	952	1,102	1,887
Wind	5	5	5	25	85	385	635	635
Coal	0	0	0	0	0	960	960	1,920
LNG	0	0	0	0	700	1,050	1,050	1,050
Cogeneration	26	26	26	44	44	44	44	44
Retired plants	n.a.	90	n.a.	n.a.	n.a.	350	n.a.	n.a.
Cumulative total	**1,664**	**1,775**	**2,114**	**2,342**	**3,152**	**4,617**	**5,017**	**6,762**
Generation tariff (USc/kWh)	11.3	10.14	9.93	8.74	8.07	7.38	7.58	7.41
Industrial/commercial tariff (USc/kWh)	14.14	12.77	12.49	11.03	10.08	9.03	9.32	9.00
Domestic tariff progression	19.78	18.30	17.73	15.85	13.46	11.14	11.19	10.43

Source: Authors' compilation based on MoEP 2014a: 69.
Note: kWh = kilowatt-hour; LNG = liquefied natural gas; MW = megawatt; USc = U.S. cent; n.a. = not applicable.
a. Time 0 = from September 2013.

Notes

1. These data are current through the end of 2014; megawatt and dollar figures are based on the date of financial close and not commercial operation.
2. Although initially conceived as part of the "5,000+ MW" program discussed in the next section, it is anticipated that this coal project will take considerably longer than the 40 months identified.
3. Unless otherwise stated, this section and the next are based in part on *Power-Sector Reform and Regulation in Africa* (Kapika and Eberhard 2013: 22–23, 26, 37, 42–43). The author is collaborating with Anton Eberhard, and has been given permission to draw heavily on relevant material.
4. KPLC was rebranded as "Kenya Power" in 2011; however, for the purposes of this report it is referred to as KPLC throughout.
5. The KPLC's predecessor was the East African Power and Lighting Co., incorporated as a public limited liability company under the Companies Act in 1922. It was a merger between the Nairobi Electric Power and Lighting Syndicate and the Mombasa Electric Light and Power Company Limited, the second of which was directly connected by way of technology acquisition to electric power developments in Zanzibar that date to 1881 (KPLC 2011: 2).
6. Energy Act No. 12 of 2006 subsequently established the Energy Tribunal in Kenya, to hear and determine appeals brought against the decisions of the ERC. The tribunal published the Energy Tribunal (Procedure) Rules 2008, on September 26, 2008.
7. Between 1960 and 1975, the government bought KPLC shares totaling 32,853,268 that represented 40.4 percent of the voting shares of the company. Under a capital restructuring in 2011 the government of Kenya shareholding increased to 50.1 percent. The KPLC has been listed on the Nairobi Stock Exchange since 1972.

8. While "5,000+ MW" and the Obama administration's "Power Africa Program" in Kenya were independently conceived, they are aligned in their goals and to some extent in their timelines as well (http://www.usaid.gov/powerafrica/partners/african-governments/kenya).
9. See annex 6A for a detailed timetable and associated capacity targets for the 5,000+ MW program.
10. Westmont independent power project (IPP), also known as the Mombasa Barge-Mounted Power Project, would bring this total to 12; however, it came into service in 1997 and had only a 7-year contract. Unlike Iberafrica, which also came into service in the same year and had a short-term contract, Westmont did not succeed in renewing its contract due to failure to agree on a lower tariff. Several more IPPs are presently under construction, namely Triumph and Kinangop, though Kinangop was halted as of the third quarter of 2015 (this is discussed in more detail later in this chapter). Gulf Energy—counted in the total—reached its commercial operation date in December 2014. Triumph was expected to complete installation, testing, and commissioning by the third quarter of 2015. In addition, construction has started on Lake Turkana.
11. The KPLC staff work in subteams (one for generation and one for transmission). As an organization, the KPLC has no lead role.
12. The development of domestic resources supports Kenya's Vision 2030 infrastructure program, which seeks to make the country more attractive to investors by, among other things, improving domestic energy supply: http://www.vision2030.go.ke/index.php/vision. The targets of the 5,000+ MW program also support those of Vision 2030.
13. The prices for commercial/industrial customers, exclusive of taxes and levies, were expected to drop from U.S. cents (USc) 14.14 to USc 9, and for domestic customers, from USc 19.78 to USc 10.45 (ERC 2014b).
14. Even the demand estimates of the 2011 Least Cost Power Development Plan were considered to be high by most industry stakeholders.
15. This figure includes 22 MW that is off-grid and owned by the government of Kenya (Rural Electrification Programme, REP), which accounts for 1 percent of total installed capacity. Also included in this figure are emergency power projects. KenGen also owns off-grid stations—Garissa and Lamu—with a total installed capacity of 5.4 MW.
16. This includes less than 1 MW of small hydropower projects, but does not include 30 MW of installed emergency power projects or exports and imports.
17. According to the MoEP Investment Prospectus (2013–16, section 5), the developers of the 5,164 MW projects initially were categorized as IPPs/Sida (Swedish International Development Cooperation Agency) partnerships (PPPs). IPPs were to contribute 4,724 MW (91.5 percent) and KenGen, 440 MW (8.5 percent) (MoEP 2013b, section 5). This, however, was revised and presently stands at a 70/30 split between IPPs and KenGen/Geothermal Development Company. Importantly, it was previously estimated that the 5,000+ MW would be carried out for K Sh 850 billion, of which the private sector would contribute K Sh 800 billion ($9.4 billion). However, "Actual costs are proving to be much higher than previously estimated, due mainly to higher costs for getting transmission lines rights-of-way and resettlement and corporate social responsibility program costs for power generation projects" (personal communication, March 3, 2015). It should be noted that the actual position of public and IPP projects awarded and under implementation will continue to change, including actual realized ratios.

    Some information for this case study was collected directly from private and public sector stakeholders who requested anonymity, including, at times, regarding their organization affiliation. Efforts are made to identify the date when information was collected by way of personal communication.

18. KenGen's large hydropower projects—namely, Gitaru (225 MW hydro with a commercial operation date of 1999) and Sondu-Miriu (60 MW hydropower with a commercial operation date of 2007)—are, however, excluded from this analysis, as there is no private sector correlate.
19. Westmont and Iberafrica reached financial close in 1996 and came online in the following year.
20. The initial bid document specified a capacity of 28 MW–100 MW, which was later refined to 64 MW and again modified to 48 MW. Today the project stands at 110 MW after expansion.
21. One of the two bids, by CalEnergy, was, however, noncompliant, as it was conditional on the bidder developing Olkaria II (which had been earmarked for KenGen) together with Olkaria III.
22. The fact that there was an appeal by a losing bidder for the Rabai project should not, however, be viewed as negative. Although it potentially delays the overall project implementation, it is part and parcel of the international competitive bidding process, and points potentially to the robustness of the process itself. Procurement appeals have been witnessed in almost all plants competitively procured after the enactment of the Public Procurement and Disposal Act in 2005—including, most recently, the three diesel generators, dating to 2010, and the latest coal plant.
23. Also in 2009, a cogenerator, Mumias Sugar Company, increased its supply to the KPLC from 3 MW to 26 MW.
24. A partnership among four Kenyan firms: Broad Holding, Interpel Investments, Tecaflex, and Southern Inter-trade.
25. A consortium of Kenyan investors, namely Gulf Energy Ltd. and Noora Power Ltd.
26. Melec PowerGen (90 percent/Lebanon).
27. Nine bids were received (after 17 firms withdrew tender documents).
28. Prunus Wind (50 MW) is also in the process of being approved.
29. The capacity factor used in capping payments for deemed generated energy is as follows: Lake Turkana Wind Project (LTWP), 55 percent; Kinangop, 39 percent; and Kipeto, 49 percent. Meanwhile, the capacity factor for which energy is paid for at a discounted price (50 percent) is as follows: LTWP, 64 percent; Kinangop, 42 percent; and Kipeto, 62 percent.
30. Kenya's Ministry of Energy awarded three concessions, but the first lost its concession (Suswa, 300 MW, due to noncompliance) and nothing has been done by the other two concessionaires. The Suswa concession was later given to the GDC.
31. The intention is for the GDC to sell steam to IPPs and KenGen, which in turn conduct the conversion to energy. To date the GDC has not been involved in power conversion projects. In the future, the GDC may be involved in geothermal projects' development models—for example, Sida PPPs in which the GDC undertakes resource-related activities, while other partners undertake energy conversion.
32. In 2013, the GDC received an $18 million grant from the Japan International Cooperation Agency to "support a comprehensive capacity strengthening programme for geothermal development in Kenya" (JICA 2013: 16).
33. Also cited by stakeholders were "politics," namely intraorganizational disputes between the chairman and the managing director of the GDC (personal communication, June 2 and 6, 2014).

34. Iberafrica presently has no payment security.
35. Tsavo received both a standby letter of credit (SBLC) and an escrow account; however, OrPower4 received only an SBLC (though the escrow account was also stipulated in OrPower4's agreement with the KPLC). With the KPLC's financial situation deteriorating during and after the drought, security measures were left to wait, and OrPower4 would eventually proceed, via a phased development approach, without any further escrow account (Eberhard and Gratwick 2007: 31–32).
36. There are two potential wind projects at Isiolo: 50 MW to be developed by KenGen and 40 MW to be developed by Blue Sea (http://www.bluesea-energy.com/bluesea%20energy%20portfolio.html).
37. Furthermore, "the total estimated potential of small, mini, micro and pico hydro systems is 3,000 MW of which about 30 MW has been developed" (MoEP 2014a: 48). In terms of a strategy to develop hydropower, five policies were identified, including one to "provide incentives for public private partnerships in small hydros" (MoEP 2014b: 49).

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CHAPTER 7

Case Study 2: Independent Power Projects and Power Sector Reform in Nigeria

Introduction

While Nigeria has the largest population and economy on the African continent, 46 percent of its citizens live below the poverty line and less than 50 percent have access to electricity. The demand for electricity far outweighs available capacity, which is less than 5 gigawatts (GW) for a population of about 170 million (table 7.1). (Compare this with South Africa, which has an installed capacity of 43 megawatts [MW] for a population one-third the size of Nigeria's.) The actual generation output rate in Nigeria, meanwhile, is far below installed capacity. In fact Nigeria's output rate per capita is among the lowest in the world, owing to poor operation and maintenance, aging generation and transmission infrastructure, fuel supply constraints, and vandalism.

Nonetheless, Nigeria has embarked on the most ambitious electricity sector reform effort of any country in Africa. Reforms were initiated in 2001 with the publication of a new power policy. The objectives of the reforms were to improve efficiency, attract private participation, and strengthen power sector performance so as to enable economic and social development. To this end, policy makers set a goal of achieving 40 GW of capacity by 2020—a goal that now seems out of reach.

As part of the reform process, Nigeria unbundled the generation, transmission, and distribution subsectors; privatized power generation stations and distribution utilities; appointed a private management contractor to manage the transmission company; and established a bulk trader. Barring South Africa, the country also boasts the largest investment in independent power projects (IPPs) in Sub-Saharan Africa.

Since 1998, five large IPPs have been developed. Several generations of IPP transactions may be attached to distinct phases of the sector reform process. The first generation of IPPs emerged before the reforms began in earnest and included

Table 7.1 Nigeria: An Overview

Population	173.6 million (2013)	Generation capacity (installed)	7,485 MW
GDP	$521.8 billion (2013)	Generation capacity (available)[a]	4,978 MW
Income level	Lower middle income	Electricity intensity (consumption per capita)	149 kWh/capita
Area	923,768 km^2	Primary electricity source	Natural gas

Sources: World Bank 2014; PTFP 2015.
Note: GDP = gross domestic product; km^2 = square kilometer; kWh = kilowatt-hour; MW = megawatt.
a. In practice, available capacity is sometimes even lower than this due to gas, hydropower, and transmission constraints.

a project-financed plant. A second generation of IPPs was developed after President Olusegun Obasanjo took office in 1999 and the new power sector policy was published in subsequent years. Two stopgap projects emerged during this period, financed by international oil companies (IOCs) and with equity contributions from the Nigerian National Petroleum Corporation. After a hiatus of a number of years, and the rejuvenation of the reform process under President Goodluck Jonathan, who took office in 2010, a third generation of IPPs was developed including a predominantly Nigerian-financed IPP that intends to serve a local grid with mainly industrial demand. Today, a new power market is being established, and a fourth generation of classic, project-financed IPPs is emerging. IPP contracts have had to be designed and negotiated afresh in the new market conditions, and appropriate credit enhancement and security measures put in place to mitigate payment and termination risks.

Nigeria thus represents a fascinating case study of accelerating investment in new power capacity, in an electricity sector undergoing radical reform. Will the next generation of IPPs be successful and lead to further investment in much-needed power generation capacity? Will risks be mitigated? Will sector reforms foster financial sustainability? Will greater competition be possible in the future? These are some of the questions that will be answered in this case study.

Nigeria's Electricity Sector: An Overview

The significant shortfall in Nigeria's generation capacity has resulted in frequent blackouts and a reliance on private generators. It is estimated that more than 30 percent of electricity is supplied by inefficient and expensive private generators (EIA 2013). By 2014, the highest peak generation recorded was 4,517 MW, while suppressed demand was estimated at 12,800 MW (Federal Ministry of Power 2014).

Prior to sector reforms, the state-owned National Electric Power Authority (NEPA), established in 1972, had the sole responsibility for generation, transmission, distribution, and retail activities in the country and operated as a vertically integrated monopoly. Lack of investment and ineffective management resulted in consistently poor performance over several decades (Ikeonu 2006).

In 1990 only 37 percent of installed capacity was operational, and transmission and distribution (T&D) losses averaged 38 percent. By the late 1990s it became apparent that the utility could not meet the power needs of the country; and the new civilian government under President Obasanjo began the gradual process of restructuring the sector (Adegbulugbe and others 2007).

Power Sector Reform

Early Reform Initiatives (The Obasanjo Era)

The National Electric Power Policy of 2001 called for the transformation of the electricity supply industry through fundamental changes in its ownership, control, and regulation. The policy identified principles for restructuring the sector and deregulating the market to attract private sector participation (Ikeonu 2006).

Evolving from this policy, the Electric Power Sector Reform Act (EPSRA) was passed in 2005, and still serves as the legal basis and regulatory framework for the reform of the industry. The act provides for:

- The creation of the Power Holding Company of Nigeria (PHCN) to take over NEPA's assets and liabilities
- The unbundling of the PHCN through the establishment of several companies to take over the assets, liabilities, functions, and staff of the holding company
- The establishment of the Nigerian Electricity Regulatory Commission (NERC)
- The development of a competitive electricity market
- The basis for determining tariffs, customer rights and obligations, and other related matters.

Following the enactment of the EPSRA, the NEPA was unbundled, vertically and horizontally, into 6 generation companies, 11 distribution companies, and a single transmission company (Transmission Company of Nigeria, TCN) under the PHCN holding company, which was tasked with preparing the successor companies for independent commercial operation and eventual privatization (Okoro and Chikuni 2007)—see table 7.2.

The Reinvigoration of Reforms (Jonathan Era)

By 2010, important steps in the reform process had been implemented, including the establishment of a regulator (NERC) and the unbundling of the PHCN, but progress was slow on the divestiture of the successor companies and the development of a competitive electricity market. Not one generation or distribution company had been sold to private investors in the five years since the EPSRA was signed into law. In 2007 the Korean firm KEPCO (Korea Electric Power Corporation) offered to purchase 51 percent of Egbin Power for $280 million. However, this deal was delayed by unresolved labor issues and the lack of a credible power purchase agreement (PPA) or agreements on pricing and the gas supply (allAfrica 2013).

A Presidential Action Committee on Power (PACP) was set up, headed by President Jonathan, to accelerate progress toward reform objectives by (1) removing obstacles to private sector involvement, (2) clarifying the government's strategy on divestiture, and (3) reforming the fuel-to-power market. These policy objectives were reaffirmed and elaborated in the Roadmap for

Table 7.2 Successor Power Generation Companies to the National Electric Power Authority, Later Privatized, Nigeria

Generation company	*Electricity distribution company*
Afam Power	Abuja
Geregu I	Benin
Sapele Power	Eko
Ughelli Power	Enugu
Kainji/Jebba Hydro Power	Ibadan
Shiroro Hydro Power	Ikeja
	Jos
	Kaduna
	Kano
	Port Harcourt
	Yola

Source: Compiled by the authors from various primary and secondary sources.
Note: Some reports might list different successor generation companies; strictly, they are defined under the Electric Power Sector Reform Act (EPSRA) as the companies created by the National Council on Privatisation (NCP) in November 2005 as part of the initial unbundling, which is not the same as those ultimately listed for privatization. Thus, the list here does not include Egbin, which was sold separately. Omotosho and Olorunsogo were also handled separately and are now owned by the Chinese engineering, procurement, and construction (EPC) companies that built them. The construction of Geregu I was completed after the initial unbundling and therefore is not strictly a successor company, though it was privatized with the others. Each successor generation company represents a single generation facility with the exception of Kainji Hydro Power, which includes both the Kainji and Jebba hydropower plants.

Power Sector Reform, published in August 2010, which set out a large number of detailed targets and milestones.

The road map outlined a strategy to remove obstacles to private sector involvement by establishing a cost-reflective tariff regime, establishing a bulk power purchaser backed by credit enhancements, settling labor disputes, and strengthening the regulator and licensing regime. The divestiture strategy outlined in the road map called for the sale of distribution companies and the thermal generation companies (via a sale of a minimum of 51 percent), the concession of hydropower generation companies, and the placement of the TCN under a private management contract.

In September 2012, the PACP was reconstituted to oversee the implementation of the federal government's agenda for power sector reform and to ensure that the reform momentum was sustained (table 7.3). A Presidential Task Force on Power (PTFP) was also established to carry out administrative work for the PACP and to monitor and facilitate the achievement of the road map's targets. In practice, however, these targets have proven to be highly ambitious, and the PTFP has lacked executive authority. The more influential implementers of the reform process have been individual institutions such as the Bureau of Public Enterprises (BPE), which has driven the privatization program, and the NERC, which has developed market rules and tariff regulations.

Privatization

In December 2010, 11 distribution companies and 6 generation companies[1] were ready for privatization. The BPE led the process, requesting expressions of

Table 7.3 Key Institutions and Their Functions in the Power Sector, Nigeria

Key institution		*Functions*
Ministry of Power		Sector policy formulation Guided by the National Electric Power Policy, the Electric Power Sector Reform Act, and the Roadmap for Power Sector Reform
Nigerian Electricity Regulatory Commission (NERC)		Regulation and monitoring of the sector by: • Promoting competition and private sector involvement • Licensing and regulating entities engaged in generation, transmission, system operations, distribution, and the trading of electricity • Setting tariffs and technical standards
Bureau of Public Enterprises (BPE)		Responsible for the privatization of federal government assets
Transmission Company of Nigeria (TCN)	Transmission service provider	Responsible for investment in and the operation of the transmission grid
	System operator	Oversees dispatch and grid control, including • System planning • Dispatch and generation forecasting • Demand forecasting
	Market operator	Administers the electricity market Manages market billing and settlement statements
Nigerian Bulk Electricity Trading (NBET)		Purchaser of electricity from generators via PPAs Manages the sale of electricity to distributors and eligible customers Publicly owned and backed by sovereign guarantees
Presidential Action Committee on Power (PACP)		Oversees power sector reforms Approves reform road map
Presidential Task Force on Power (PTFP)		Implementing agency for the PACP Coordinates various agencies involved in removing private sector obstacles

Source: Compiled by the authors from various primary and secondary sources.
Note: PPAs = power purchase agreements.

interest and conducting international road shows for the privatization of the successor companies. The bureau subsequently released a request for proposals, in response to which 25 bids for the 6 generation companies and 54 bids for the 11 distribution companies were received. Preferred bidders were announced in October 2012, following a rigorous technical and financial evaluation. Transaction and industry documents were signed in February 2013, alongside an initial payment of 25 percent. Bidders then had until August 21, 2013, to pay the remaining 75 percent for the companies (BPE 2013).

Egbin Power had concluded its privatization transaction in 2013; a joint venture between KEPCO and the Sahara Power Group agreed to acquire an additional 19 percent equity stake over their original 2007 offer, bringing their total shareholding to 70 percent, for a total acquisition cost of $407 million.

Five of the generation companies and 10 of the distribution companies were sold for a total value of approximately $3 billion, with much of the proceeds used to pay off previous PHCN employees. Ownership was handed over in November 2013. The Afam generation plant and the Kaduna Electricity Distribution Company deals took longer but have since also been concluded.

The federal government retained 40 percent ownership stakes in the distribution companies and 49 percent in the Geregu I successor generation company; the remaining thermal successor generation companies were fully privatized. The two hydropower companies—Kainji and Shiroro—were concessioned, with the state retaining ultimate ownership of assets.

In addition to the sale of the successor generation companies, two other state-owned plants were sold via debt equity swaps with the Chinese contractors who built them: Omotosho Phase I (March 2013) and Olorunsogo Phase I (March 2014) (This Day Live 2013b). The local partner for the privatized assets was the engineering, procurement, and construction (EPC) contractor SEPCO-Pacific.

Conceived in 2004, 10 national integrated power projects (NIPPs) were initiated to increase the generation capacity of the country, including associated T&D projects. The projects involved gas-fired power plants with supporting transmission and gas delivery infrastructure; their combined capacity was close to 5,000 MW. These projects were initially funded and owned by the state through the three tiers of government (federal, state, and local) and were managed by the Niger Delta Power Holding Company (2013). Following many delays, the 10 projects were either complete or near completion as of late 2015. However, gas supply constraints remained an issue and only some were fully operational.

In line with the government's privatization program, the 10 NIPP facilities were also earmarked for divestiture. The plants are being privatized through the sale of 80 percent of the state's equity in them, with 20 percent remaining with the Niger Delta Power Holding Company. Preferred bidders have been selected for the 10 facilities, and though the handover of the plants was originally scheduled for June 2014, these transactions had not yet been concluded in late 2015. Pending litigation and amid uncertainty surrounding gas supply, some of the plants remain incomplete; how to operate a Transitional Electricity Market (TEM) remains a question (Daily Independent 2014).

Market Evolution and Financial Sustainability

The market rules envisage that the competitive electricity market will evolve through four stages: (1) pretransition, (2) transition, (3) medium term, and (4) long term (table 7.4).

The market rules also define procurement procedures for new power. The NERC's Regulations for the Procurement of Generation Capacity, published in 2014, simplify these procedures for the early stages of market development. The regulations cover new capacity procured by the bulk trader or distribution companies. Prior to the regulations, all IPPs that had been issued licenses involved unsolicited, directly negotiated proposals. The objective of the regulations is to establish a systematic, transparent, and competitive process to

Table 7.4 Evolution of the Power Market, Nigeria

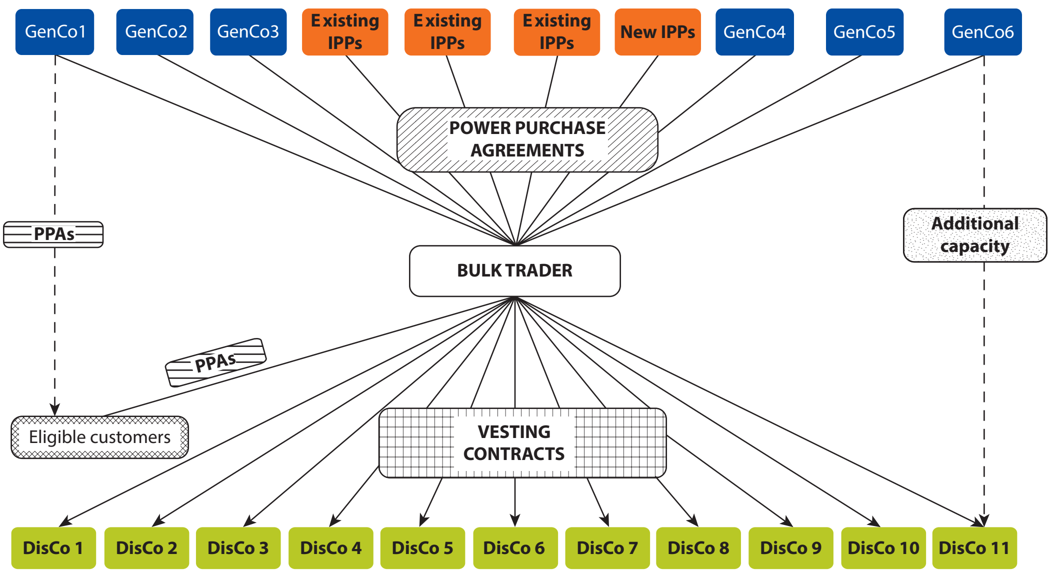
Market stage	*Market characteristics*
Pretransition	Unbundling and privatization of the PHCN Establishment of the NELMCO and bulk trader Preparation of market rules and governing documentation
Transition	Successor companies commence functions[a] Bulk trader commences trading with generators and distributors—TEM No centrally administered balancing mechanism for the market
Medium term	Bulk trader no longer enters into PPAs Commence novation of PPA rights to other licensees Distributors may enter into bilateral contract for purchase and sale of energy[b] Full wholesale competition (spot market) Centrally administered balancing mechanism for the market
Long term	Capacity sufficient to meet demand Retail competition (consumers have choice of provider)

Source: Compiled by the authors from various primary and secondary sources.
Note: NELMCO = Nigeria Electricity Liability Management Company (a publicly owned company that assumes the liabilities of the PHCN); PHCN = Power Holding Company of Nigeria; PPA = power purchase agreement; TEM = Transitional Electricity Market.
a. Successor companies actually commenced functions in the pretransitional stage.
b. Distribution companies can enter into bilateral contracts during the TEM, in defined circumstances.

procure new capacity at the least cost to the consumer. The system operator is required to publish a five-year demand forecast and an annual generation report. If the report indicates that contracting for new capacity is required within 12 months, the buyer (a creditworthy distribution company or the Nigerian Bulk Electricity Trading Plc [NBET]) may begin procurement procedures in line with the regulations and with approval from the NERC (NERC 2014).

The market rules govern contracting through the transitional and medium-term stages of the market. For the vesting contracts to be activated, the TEM should have been in place at the time the successor companies were privatized. However, many of the conditions required for declaring the TEM—such as metering—were not met in full, and there were still concerns around financial sustainability. So, instead, a set of interim rules was issued by the NERC, first in December 2013 (effective from November 1, 2013) and extended to April 2014. After many delays the TEM was finally declared in February 2015. The bulk trader, NBET, is intended to act as the credible off-taker and aggregator to guarantee liquidity in the market (figure 7.1). Electricity is bought from successor generation companies and from NIPPs and IPPs—through PPAs—and then sold on to distribution companies and eligible customers. In the future, the bulk trader need not be the only off-taker of power; any creditworthy distribution company or eligible customer will be able to negotiate a PPA directly with a generation company or IPP. The bulk trader is required to be in place only until the distribution companies have established creditworthiness, and until the accounting, managerial, and governance systems have developed enough to handle a more sophisticated market of multiple buyers and sellers (PACP 2010).

Figure 7.1 Transitional Electricity Market Structure, Nigeria



Note: DisCo = distribution company; GenCo = generation company; IPP = independent power project; PPA = power purchase agreement.

Despite delays and considerable challenges, privatization has taken root in Nigeria. It is remarkable that private investors actually reached financial close without the TEM and the security arrangements (partial risk guarantees, PRGs) to be provided by the World Bank. Investors probably take some comfort from the fact that the reforms are being supported at the highest political level. Besides, investors are keen to position themselves in a market that has enormous growth potential, following the successful experience of Nigeria's liberalization of the telecommunication industry.

Despite this impressive progress in sector reform, some serious challenges remain. Revenue collection from customers is still inadequate to cover the costs of power delivery. Insufficient revenue is flowing from customers—through distribution companies—to generators, gas suppliers, and investors. The Central Bank of Nigeria (CBN) devised a financial rescue package in the form of the Nigerian Electricity Market Stabilization (NEMS) facility to inject liquidity into the sector and address legacy debts. These amounts are repaid through an understanding that the NERC-approved tariffs would include a premium over a 10-year period to fund these debts. The NERC revised tariffs through the second Multi-Year Tariff Order (MYTO-2.1).[2] However, in March 2015 the NERC arbitrarily removed assumptions of distribution companies' collection losses. This in effect reduced the approved tariffs, thus threatening the financial viability of the sector again. A number of distribution companies gave notice of *force majeure*. Subsequently, the new administration under President Muhammadu Buhari was forced to intervene, and brokered an agreement with the NERC to reconsider its tariff ruling.

Another area of concern has been the viability and reliability of gas supply to power generators; increasing the gas supply is critical to increasing the delivery of power to distribution companies and customers. A decision was made in late 2014 to increase the regulated supply price of gas to $2.50/million standard cubic feet (mmscf)[3] plus pipeline transport costs of $0.80/mmscf (however, as of late 2015, the new price had still not been implemented). Also, in the period leading up to the March 2015 elections there were numerous incidents of vandalism and the sabotage of gas pipelines.

Another key challenge is insufficient investment to facilitate the full evacuation of power from the new NIPPs and existing generation companies. There are also transmission constraints on transporting available power throughout the country. And distribution companies have barely begun the job of improving metering, billing, collections, loss reductions, and service quality. These combined factors may turn public opinion against the reform process.

Another concern is the organizational fragility of the TCN. The original contract with the Canada-based Manitoba Hydro International (MHI), appointed as management contractor, ended in July 2015 and was then extended for a year. However, there is still no credible succession plan. Without a cooperative and well-designed succession plan, the TCN is on the road to institutional collapse—with dire consequences for the entire power sector.

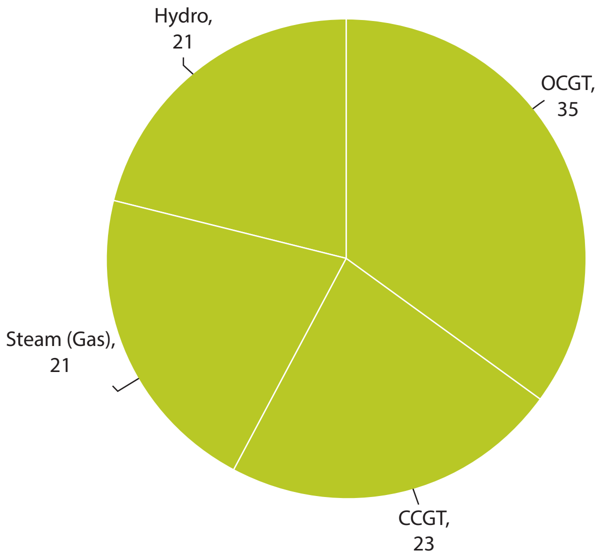
Amid such unresolved issues, particularly surrounding the financial sustainability of the sector, it is very difficult for new IPPs to enter the power market. While the pioneering Azura IPP may soon be followed by an ExxonMobil IPP, more than 50 IPP projects wait in the wings—many of them frustrated by gas constraints and an electricity sector in flux. Nevertheless, as the NBET becomes operational, capacity is being built to negotiate and contract with IPPs. The NBET serves as the "principal buyer" and thus offers a clear access point for future investors. As contracts are concluded with pioneer IPPs, the road map for subsequent investments will be clearer and easier.

The NBET model might not be easily replicated in other African countries—the transaction costs of establishing a separate, dedicated institution in small power markets is probably too high—but it does point to the importance of, at minimum, creating a capable central wholesale electricity purchasing function that can serve as a transparent and creditworthy counterpart for PPA contracts with IPPs. This function could be established within national transmission companies, but it would be important to ring-fence these market operations from transmission and system operations, as well as from power generation. Functional capability to contract IPPs is important for attracting new private investment and is an area that needs more attention in the future.

Installed Generation Capacity

Historically, Nigeria's electricity sector has operated far below its installed capacity; utilization rates have averaged below 40 percent for over three decades. Aging infrastructure, poor maintenance, vandalism, and gas supply constraints have all negatively affected the performance of the sector.

Figure 7.2 Energy Produced, by Technology: Nigeria, 2013 Averages
percent



Source: Compiled by the authors from system operator data.
Note: CCGT = combined-cycle gas turbine; OCGT = open-cycle gas turbine.

Presently, the installed capacity of Nigeria is estimated to be under 7.5 GW, of which less than 5 GW is available.[4]

There are 23 grid-connected and operational power plants in Nigeria. Given the country's abundance of natural gas, the generation fleet is largely gas fired; three hydropower plants provide the balance (figure 7.2). In January 2014, the TCN estimated that 2,994 MW of capacity was lost due to gas supply constraints. Furthermore, 80 percent of gas power plants are reported to be regularly deprived of gas (Punch 2014).

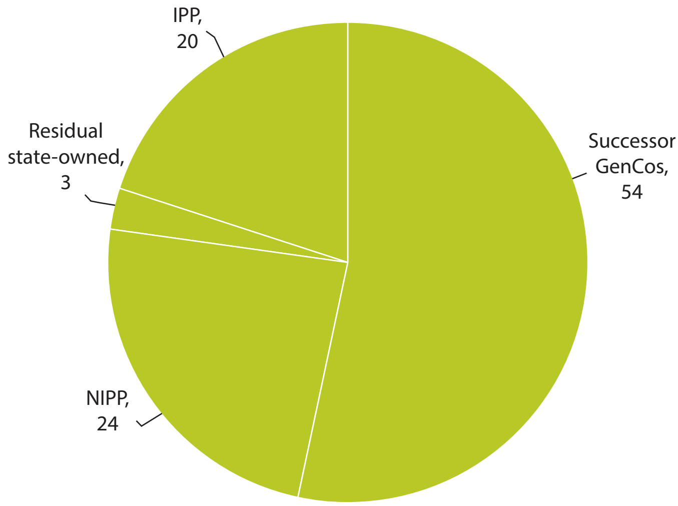
Power plants can be divided into four categories based on their ownership: (1) IPPs, (2) successor generation companies (including successor companies and plants privatized before the October 2013 sale), (3) NIPPs (built with public money but undergoing privatization), and (4) residual state-owned plants[5] (not part of PHCN) (see figures 7.3 and 7.4 and tables 7.5–7.8).

Power Sector Performance

The performance of the generation fleet was analyzed from January 2012 through October 2013, using data from the system operator. Over the reference period, theoretically available capacity averaged around 5,200 MW; the actual energy sent out had an average peak of only about 3,500 MW (figure 7.5).

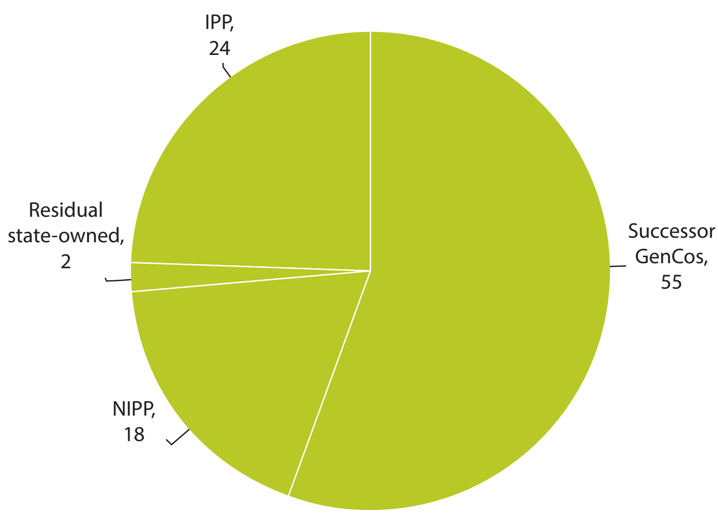
The average monthly capacity factors[6] of IPPs, successor generation companies, and NIPP plants are shown in figures 7.6 and 7.7 for open- and combined-cycle

Figure 7.3 Installed Capacity, by Project Type: Nigeria, 2013 Averages
percent



Source: Compiled by the authors from system operator data.
Note: GenCos = generation companies; IPP = independent power project; NIPP = national integrated power project.

Figure 7.4 Energy Produced, by Project Type: Nigeria, 2013 Averages
percent



Source: Compiled by the authors from system operator data.
Note: GenCos = generation companies; IPP = independent power project; NIPP = national integrated power project.

Table 7.5 Residual State-Owned Plants, Nigeria

Plant	*Fuel*	*Installed capacity (MW)*	*COD*	*Location*	*Ownership*	*Plant cost (US$, millions)*
Omoku	Gas–OCGT	150	2005	Omoku, Rivers State	Rivers State	132
Trans Amadi	Gas–OCGT	136	2002	Port Harcourt, Rivers State	Rivers State	34
Ibom Power	Gas–OCGT	190	2009	Akwa Ibom State	Ibom State	n.a.
Rivers IPP (Eleme)	Gas–OCGT	95	2005	Eleme, Rivers State	Rivers State	n.a.

Source: Compiled by the authors, based on various primary and secondary source data.
Note: COD = commercial operation date; IPP = independent power project; MW = megawatt; OCGT = open-cycle gas turbine; n.a. = not applicable.

Table 7.6 Successor Power Generation Companies, Now Privatized, Nigeria

Plant	*Fuel*	*Installed capacity (MW)*	*Available capacity[a] (MW)*	*COD*	*Location*	*Ownership*
Jebba	Hydro	578	450	1985	Jebba, Niger State	Mainstream Energy Solutions (concession)
Kainji	Hydro	760	580	1968	Kainji, Niger State	
Shiroro	Hydro	600	450	1989	Shiroro, Niger State	North-South Power Ltd. (concession)
Geregu I	Gas–CCGT	414	138	2007	Geregu, Kogi State	Amperion Power
Ughelli (Delta)	Gas–OCGT	900	340	1975/1978/2008	Ughelli, Delta State	Transcorp/Woodrock
Afam IV/V	Gas–OCGT	776	75	1982/2002	Afam, Rivers State	*Still to be divested*—preferred bid: Taleveras Group
Sapele	Gas–steam	1,020	90	1978	Sapele, Delta State	CMEC/Eurafric Energy Ltd.
Omotosho I	Gas–OCGT	335	42	2005	Omotosho, Ondo State	CMEC
Olorunsogo I	Gas–OCGT	335	168	2007	Olorunsogo, Ogun State	SEPCO-Pacific Partners
Egbin	Gas–steam	1,320	880	1986	Egbin, Lagos State	KEPCO

Source: Compiled by the authors, based on various primary and secondary source data.
Note: CCGT = combined-cycle gas turbine; CMEC = China Machinery Engineering Corporation; COD = commercial operation date; KEPCO = Korea Electric Power Corporation; MW = megawatt; OCGT = open-cycle gas turbine.
a. Available as of September 2013.

Table 7.7 Independent Power Projects, Nigeria

Plant	*Fuel*	*Installed capacity (MW)*	*COD*	*Location*	*Ownership*	*Plant cost (US$, millions)*
AES Barge Ltd.	Gas–OCGT	270	2001	Egbin, Lagos State	AES	240
Afam VI (Shell)	Gas–CCGT	650	2008	Afam, Rivers State	Shell	540
Okpai (Agip)	Gas–CCGT	480	2005	Okpai, Delta State	Agip	462
Aba Integrated Power Project (Geometric)	Gas–OCGT	140	2013	Aba, Abia State	Geometric Power	250

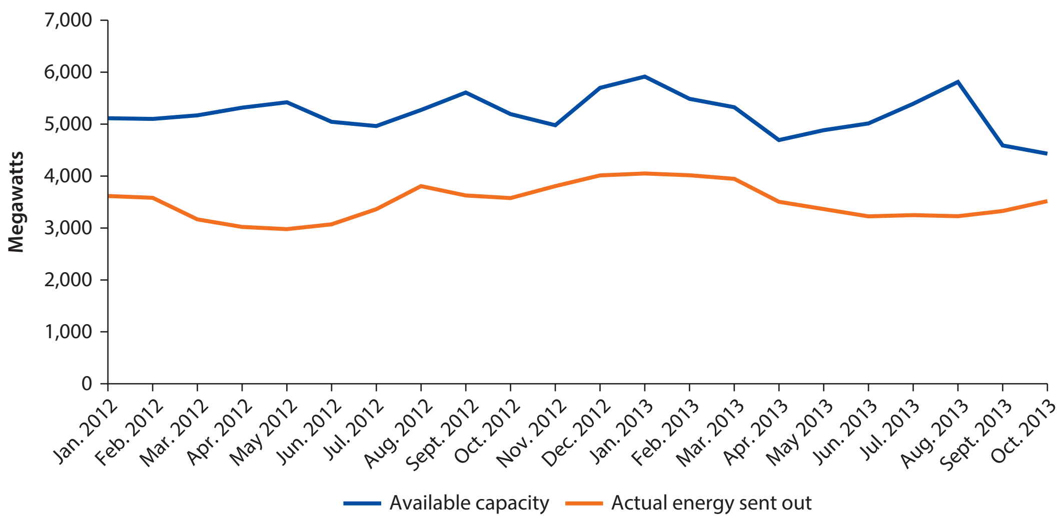
Source: Compiled by the authors, based on various primary and secondary source data.
Note: CCGT = combined-cycle gas turbine; COD = commercial operation date; MW = megawatt; OCGT = open-cycle gas turbine.

Table 7.8 National Integrated Power Projects, Nigeria

Plant	*Fuel*	*Installed capacity (MW)*	*Location*	*Preferred bidder*	*Deal value (US$, millions)*
Alaoji	Gas–CCGT	1,131	Alaoji, Abia State	AITEO Consortium	902
Benin (Ihovbar)	Gas–OCGT	508	Ihovbor, Edo State	EMA Consortium	580
Calabar	Gas–OCGT	634	Calabar, Cross River State	EMA Consortium	625
Egbema	Gas–OCGT	381	Egbema, Imo State	Dozzy Integrated Power Ltd.	415
Gbarain	Gas–OCGT	254	Gbarain, Bayelsa State	KDI Energy Resources	340
Geregu II	Gas–OCGT	506	Geregu, Kogi State	Yellowstone Electric Power Ltd.	613
Ogorode (Sapele II)	Gas–OCGT	508	Sapele, Delta State	Daniel Power	531
Olorunsogo II	Gas–CCGT	754	Olorunsogo, Ogun State	ENL Consortium	751
Omoku II	Gas–OCGT	265	Omoku, Rivers State	Shynobe International Ltd.	319
Omotosho II	Gas–OCGT	513	Omotosho, Ondo State	Omotosho Electric Power	660

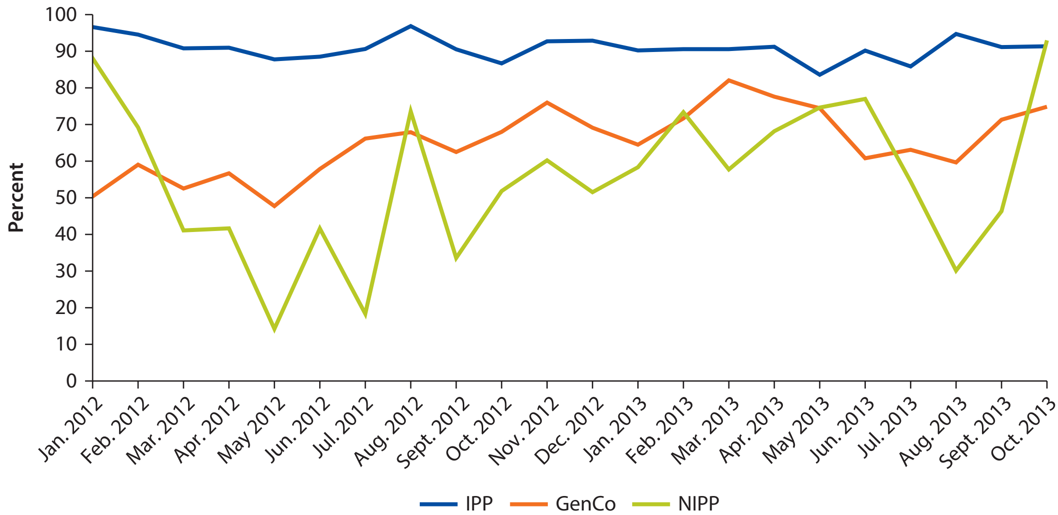
Source: Compiled by the authors, based on various primary and secondary source data.
Note: CCGT = combined-cycle gas turbine; MW = megawatt; OCGT = open-cycle gas turbine.

Figure 7.5 Performance of Electricity Sector: Nigeria, January 2012–October 2013



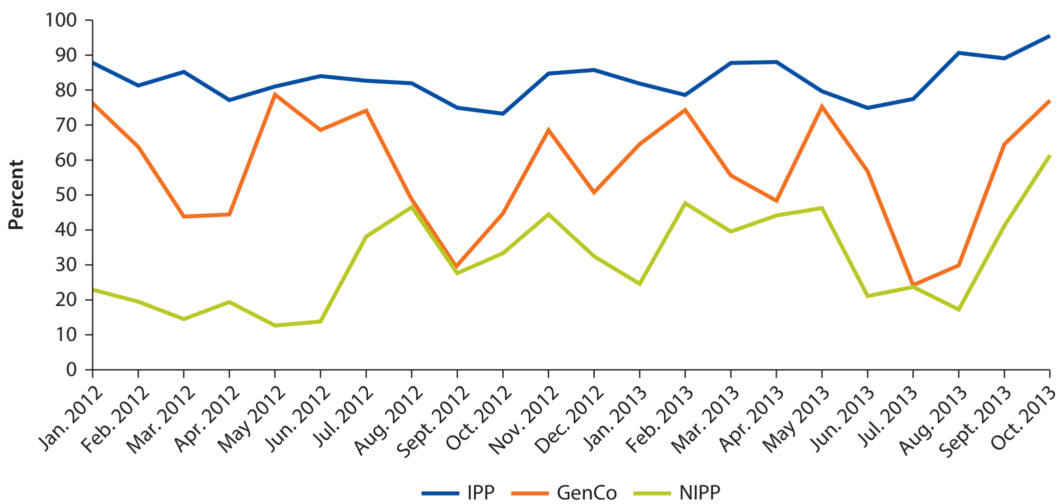
Source: Compiled by the authors from system operator data.

Figure 7.6 Average Monthly Capacity Factors of Open-Cycle Gas Turbines: Nigeria, January 2012–October 2013



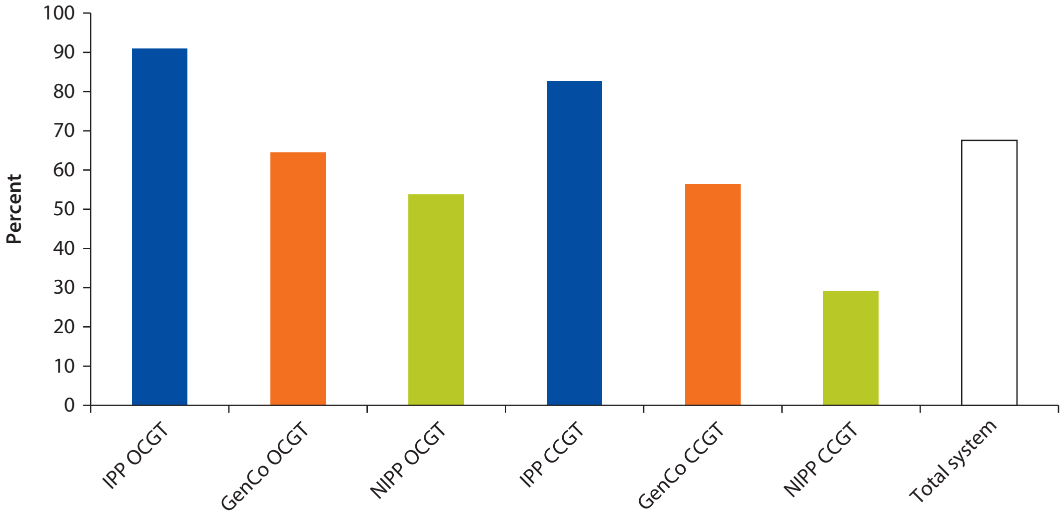
Source: Compiled by the authors from system operator data.
Note: Open-cycle gas turbine (OCGT) sample: IPP—AES; GenCos—Afam IV/V, Delta, Olorunsogo I, Omotosho I; NIPPs—Omotosho II, Sapele II. GenCo = generation company; IPP = independent power project; NIPP = national integrated power project.

Figure 7.7 Average Monthly Capacity Factors of Combined-Cycle Gas Turbines: Nigeria, January 2012–October 2013



Source: Compiled by the authors from system operator data.
Note: Combined-cycle gas turbine (CCGT) sample: IPP—Afam VI, Okpai; GenCos—Geregu I; NIPP—Olorunsogo II. GenCo = generation company; IPP = independent power project; NIPP = national integrated power project.

Figure 7.8 Capacity Factors of Various Technologies and Owners: Nigeria, FY2012/13



Source: Compiled by the authors from system operator data.
Note: CCGT = combined-cycle gas turbine; GenCo = generation company; IPP = independent power project; NIPP = national integrated power project; OCGT = open-cycle gas turbine.

gas turbines (OCGTs and CCGTs). Only plants that were operational for the majority of the reference period were included.

Privately owned OCGT and CCGT plants in Nigeria are operated much closer to their available capacity than the state-owned generation companies and NIPP plants. IPPs also seem to have more consistent capacity factors than publicly owned plants.

The average capacity factors are summarized in figure 7.8, which includes the total system's average capacity factor. The NIPP plants are newer plants, and the lower capacity factors experienced over the period are likely attributable to gas supply constraints. It should also be noted that the publicly financed NIPPs took up to 10 years to build and complete, much longer than the IPPs.

Electricity Pricing

A principal driver of Nigeria's power sector reforms is the need for cost-reflective tariffs. Prior to the reforms, electricity was considered a public welfare service to be provided by the government, and was therefore heavily subsidized. A uniform pricing structure was used, and tariffs remained fixed for years despite rising energy costs. Between 2002 and 2008, the tariff averaged around naira (₦) 4.50–₦6.00/kilowatt-hour (kWh) (U.S. cents [USc] 3–4/kWh), and the PHCN operated with monthly deficits of close to ₦2 billion ($12.1 million)—see Bello 2013. These tariffs restricted the ability of the utility to invest in new infrastructure and discouraged the entry of private IPPs.

The EPSRA (2005) describes the objectives of tariff regulations for the industry and places responsibility for the setting and reviewing of electricity prices with the NERC. As described in the act, electricity prices and tariff methodologies shall:

- Allow a licensee that operates efficiently to recover the full costs of its business activities, including a reasonable return on the capital invested in the business.
- Provide incentives for the continued improvement of the technical and economic efficiency with which the services are provided.
- Provide incentives for the continued improvement of quality of services.
- Give consumers economically efficient signals regarding the costs that their consumption imposes on the licensee's business.
- Avoid undue discrimination between consumers and consumer categories.
- Phase out or substantially reduce cross-subsidies.

The NERC employs the MYTO methodology for determining tariffs. The MYTO provides a 15-year price path for the industry with minor[7] tariff reviews every two years and major[8] reviews every five years (NERC 2012). Introduced in 2008, the MYTO-1 was based on an efficient new-entrant model; the long-run marginal cost (LRMC[9]) method was used to determine the unit price of an efficient plant. Tariffs for the first five years ranged from ₦9/kWh to ₦11.50/kWh (USc 5–7/kWh), and the gap between the required tariff and what customers were billed was gradually removed; only the poorest customers now receive a subsidy (Bello 2013).

The MYTO-2 (for the period up to 2017) came into effect on May 31, 2012, and included more flexibility in wholesale generation pricing and considered new fuel types such as coal and renewables. In addition, market data (industry costs and so on) for the development of tariffs and regulatory financial models are now obtained directly from market participants as opposed to regulator estimates (Bello 2013). Following a loss verification exercise, the NERC published an amended MYTO in early 2015 that disallowed collection losses. Exchange rate, inflation, generation, and gas price adjustments were also made. Tariff increases for some residential customers were frozen. The arbitrary reduction of tariffs by the NERC contradicted terms in the privatization agreements and threatened the financial viability of the sector. Following elections, and the advent of the new administration, in mid-2015 the NERC agreed to reconsider its previous decision and move toward cost-reflective tariffs.

State Investment in Power Projects in Nigeria

The 10 NIPPs—totaling 5,000 MW—compose the largest publicly financed power program in Sub-Saharan Africa, outside South Africa. The program was initiated during the Obasanjo presidency with an allocation of $2.5 billion in 2005 from the Excess Crude Account (ECA, owned by all three tiers of government and used to collect oil revenues above a defined benchmark price).

Following a change in government in 2007, funding for the NIPPs was suspended for 2.5 years while the new Jonathan administration queried funding, legal, and political issues surrounding the program. The release of a further $5.4 billion was then approved as a power emergency fund to complete the projects and fund transmission and gas infrastructure (PTFP 2013).

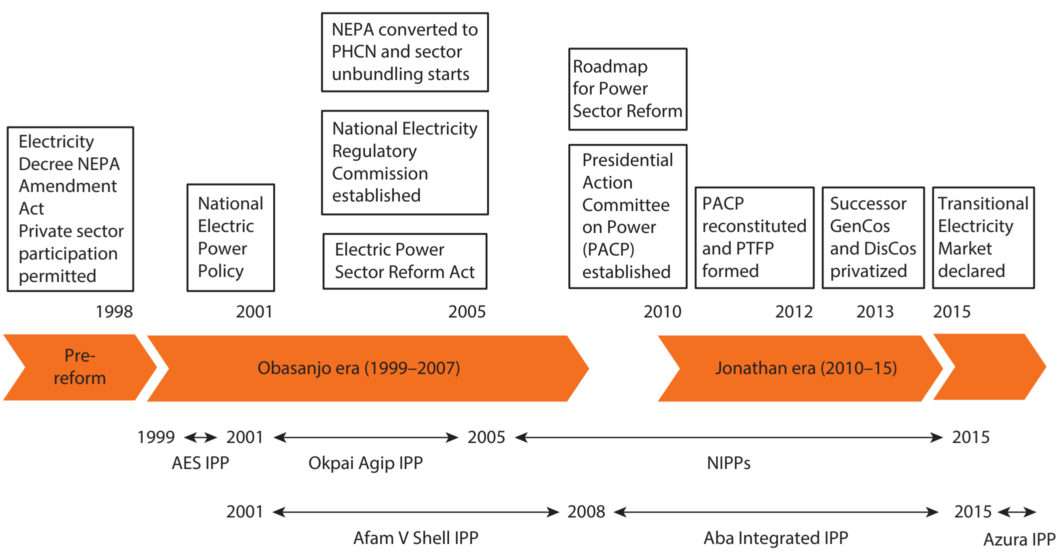
Ten years after the initiation of this program, several power stations are still not fully commissioned. The poor construction and completion record of the NIPPs stands in stark contrast to the IPPs described below.

The privatization of the NIPPs has also not gone as well as the sale of the successor generation and distribution companies. It has been delayed in part by gas and transmission constraints and the lack of sovereign guarantees for payment and political risks. The government expects to generate about $3.2 billion from the sale of the NIPP plants, with at least half of the proceeds being earmarked for investment in transmission.

Independent Power Project Investments in Nigeria

IPPs in Nigeria have developed over a period of 15 years and in very different policy, legislative, regulatory, and market contexts; accordingly, they have been structured and financed in various ways. Figure 7.9 shows the timing of IPP investments in relation to key reform interventions. As previously indicated, there have been four generations of IPPs. The first-generation AES IPP was initiated in the pre-reform period. Then two IOC stopgap IPPs—Okpai and Afam V—were

Figure 7.9 Timeline of Power Sector Reform Interventions and Generation Investments: Nigeria, 1998–2015



Note: DisCos = distribution companies; GenCos = generation companies; IPP = independent power project; NEPA = National Electric Power Authority; NIPP = national integrated power project; PHCN = Power Holding Company of Nigeria; PTFP = Presidential Task Force on Power.

developed with generous, but not-to-be repeated, tax incentives as President Obasango kick-started power sector reforms. President Jonathan later reinvigorated power sector reforms with the development of a Roadmap for Power Sector Reform and the inauguration of the PACP and the PTFP. The Aba Integrated IPP was developed during this period. It has been something of an anomaly, as it is not connected to the national grid and seeks to serve mainly industrial, local demand. Finally, with the TEM and NBET being established, a new set of classic, project-financed IPPs were developed, with Azura the first of the new batch.

Since power sector reforms opened up the market, there has been considerable interest from the private sector; the NERC received over 100 applications for generation licenses. However, as alluded to earlier, gas supply remains a major limiting factor, and the NERC has declared that only generators with a secured gas supply will be considered for a license (Business Day 2014).

The NERC Regulations for Embedded Generation (2012) make provision for embedded generators of below 20 MW to operate without central dispatch. This might open space for more regional and local IPPs to enter the market.

AES Barge Ltd.

The AES Barge project was the first IPP deal in Nigeria, dating back to 1999 (table 7.9). Amid an emergency power situation, and following the 1998 passage of a law[10] allowing private sector participation, negotiations for a two-part project began. The plans were for a 90 MW diesel barge-mounted plant and a 560 MW

Table 7.9 Overview of AES Barge, an Independent Power Project, Nigeria

Plant	AES Barge	Contract details	13.25-year PPA (build-own-operate)
Location	Egbin, Lagos State		U.S. dollar denominated
Capacity	270 MW		Flat capacity charge (OECD CPI indexed)
			$19.35/kW/month (November 2006)
			No energy charge
Ownership	95% AES Limited (U.S.)	Financing	$120 million loan
	5% Yinka Folawiyo Power Limited (Nigeria)		Foreign and local debt
			(Rand Merchant Bank [RMB], FMO, African Export-Import Bank, Diamond Bank Nigeria, Fortis Bank, KfW, United Bank for Africa, African Merchant Bank)
Technology	Open-cycle gas turbines (9 × 30 MW)	Security	Sovereign guarantee—$60 million letter of credit (Ministry of Finance)
			OPIC political risk insurance
Value	$240 million ($888/kW)	Fuel contract	No separate fuel supply contract
COD	June 2001		NEPA (now PHCN) provides fuel purchased directly from Nigeria Gas Company

Sources: Eberhard and Gratwick 2012; Adegbulugbe and others 2007.
Note: COD = commercial operation date; CPI = consumer price index; FMO = Netherlands Development Finance Company; KfW = Kreditanstalt für Wiederaufbau; kW = kilowatt; MW = megawatt; NEPA = National Electric Power Authority; OECD = Organisation for Economic Co-operation and Development; OPIC = Overseas Private Investment Corporation; PHCN = Power Holding Company of Nigeria; PPA = power purchase agreement.

permanent gas-fired plant with a common PPA. The deal was directly negotiated within a few months between the U.S.-based Enron, the Lagos state government, the NEPA, and the Ministry of Power and Steel (Eberhard and Gratwick 2012).

Strong objections to the project and mounting public pressure resulted in the deal being modified. The objections included the lack of a transparent and competitive process, excessive contract termination payments, a lack of penalties for poor performance, and excessive capacity charges. The project design was modified by increasing the barge-mounted plant to 270 MW and changing the fuel type from diesel to natural gas. Plans for a 560 MW permanent plant were shelved, and the new deal was concluded six months later, in 2000 (Eberhard and Gratwick 2012).

Prior to filing for bankruptcy, the majority shareholder, Enron, sold its stake in the plant to AES Limited (95 percent over two sales) and Yinka Folawiyo Power Limited (5 percent), which had been the local adviser to Enron since project inception. Enron did not complete construction, and the EPC contract was handed over to the AES.

The plant began operation in 2001. In the absence of a reform policy and law, initial risk allocation was skewed in favor of the private developer. Certain terms in the contract, such as the availability deficiency payment terms and tax exemption certificate, have since been renegotiated. Furthermore, there have been fuel supply constraints on the plant's operations relating to unrest in the Niger Delta region. Supply constraints and uncompetitive operating costs have meant that the plant has been essentially mothballed for some years.

Okpai (Agip)

The next IPP deal also came as a result of severe electricity supply shortages. Okpai (table 7.10) resulted from a policy, launched in 2001, that aimed to contain the problem of gas being wasted through flaring from oil fields in Nigeria. In 2001, during the Obasango presidency, the NEPA invited prequalified bidders (namely IOCs) to bid for a two-phase 480 MW gas plant (300 MW OCGT with conversion to 480 MW CCGT). This deal included the required gas infrastructure and was to be structured on a build-own-operate (BOO) basis (Eberhard and Gratwick 2012). The application of the Associated Gas Framework Agreement (AGFA) to these investments allowed IOCs to offset the costs under the joint venture oil and gas activities and depreciate the assets rapidly. These were undoubtedly the most attractive incentives offered to private power generation investments on the continent.

A consortium led by Agip Oil won the bid to build the plant, and the PPA was signed in 2001. While it involved less back-and-forth than the preceding IPP deal, the project was subject to dramatic cost escalations (from $300 million to $462 million) between contracting, signing, and the start of commercial operations in 2005. The escalations were mainly due to acts of vandalism and an underestimation of the required gas infrastructure. They prompted a dispute among the parties involved; until this was settled (out of court), payments were not made to the IPP (Eberhard and Gratwick 2012).

Table 7.10 Overview of Okpai, an Independent Power Project, Nigeria

Plant	Okpai IPP	Contract details	20-year PPA (build-own-operate)
Location	Okpai, Delta State		U.S. dollar denominated
Capacity	450 MW		Capacity charge: $13.00/kW/month (2006)
			Energy charge: 2.2 USc/kWh (2006)
Ownership	60% NNPC	Financing	100% equity financed
	20% Agip Oil Company (Italy)		60% NNPC
	20% Phillips Oil Company (U.S.)		20% Agip
			20% Phillips
Technology	Combined-cycle gas turbine	Security	PPA backed by oil revenue of NNPC
Value	$462 million (includes gas infrastructure)	Fuel contract	Agip to provide fuel
COD	2005	EPC	Alstom

Sources: Eberhard and Gratwick 2012; Adegbulugbe and others 2007.
Note: COD = commercial operation date; EPC = engineering, procurement, and construction; IPP = independent power project; kW = kilowatt; kWh = kilowatt-hour; MW = megawatts; NNPC = Nigerian National Petroleum Corporation; PPA = power purchase agreement.

Okpai and Afam VI (described below), were entirely equity financed, with the Nigerian National Petroleum Corporation (NNPC) taking a majority share and the oil companies the balance. Generous depreciation allowances made these projects attractive for investors. Thus, these were not classic IPPs relying on non-recourse project finance.

Afam VI (Shell)

As with the Okpai IPP, the NEPA invited several IOCs to bid for the two-part Afam project. The project included the refurbishment of Afam V and the procurement of the new Afam VI plant (table 7.11). A consortium led by Shell Petroleum Development Company won the bid in 2001; the plant began operations in 2008.

Table 7.11 Overview of Afam VI, an Independent Power Project, Nigeria

Plant	Afam Phase VI	Contract details	20-year PPA
Location	Afam, Rivers State		Afam V (acquire-own-operate)
Capacity	630 MW		Afam VI (build-own-operate)
			U.S. dollar denominated PPA
Ownership	55% NNPC	Financing	100% equity financed
	30% Shell (UK/Netherlands)		55% NNPC
	10% Elf/Total (France)		30% Shell
	5% Agip Oil Company (Italy)		10% Elf
			5% Agip
Technology	Combined-cycle gas turbine (3 × 148 MW gas turbine) (1 × 230 MW steam turbine)	Security	Letter of credit (Ministry of Finance)
Value	$540 million	Fuel contract	Shell provides gas supply
COD	2008	EPC	Daewoo E&C

Source: Eberhard and Gratwick 2012.
Note: COD = commercial operation date; EPC = engineering, procurement, and construction; MW = megawatt; NNPC = Nigerian National Petroleum Corporation; PPA = power purchase agreement.

Arrangements were similar to that of the Okpai IPP, and involved a U.S.-dollar-denominated PPA and full equity financing. The main difference between the arrangements was that the PPA in the Afam VI deal was backed by a letter of credit (LC) from the Ministry of Finance and not by the oil revenues of the NNPC. A LC was sufficient security for the deal.

Other international petroleum companies with a presence in Nigeria—such as Total, Exxon, and Chevron—did not participate in these IPP opportunities, although Chevron is now looking at a new IPP development to monetize domestic gas (as international liquefied natural gas [LNG] prices fall). Other IOCs could follow, although they are unlikely to benefit from the generous tax incentives that were offered under the AGFA.

Aba, an Integrated Power Project

The Aba project (table 7.12) is an integrated generation and distribution project that was directly negotiated with the city of Aba in Abia State and was spearheaded by the former minister of power, Barth Nnaji, who chairs the lead sponsor, Geometric Power. A 141 MW OCGT plant and a distribution network were developed in the Aba and Ariaria business district under a 15-year lease between Geometric and the Enugu Distribution Company (LeBoeuf, Lamb, Greene, & MacRae 2006). The project is ring-fenced and does not feed into the national grid operated by the TCN.

Construction began in 2008. The project was to be commissioned in October 2013, but the plant is not yet operational because of issues with the gas pipeline and disputes regarding the licensed area. Stretching 27 kilometers (km) from the plant to Shell's Imo River facility, the gas pipeline was completed in September 2013; however, inconsistencies in design between Geometric Power and Shell caused a setback (Africa Oil and Gas Report 2014). An even more serious issue

Table 7.12 Overview of Aba, an Integrated Power Project, Nigeria

Plant	Aba Integrated Power Project	Contract details	PPAs with Aba distribution company (same parent company) and directly with Aba industrial customers
Location	Aba, Abia State		
Capacity	141 MW		
Ownership	Geometric Power Ltd. (Nigeria)	Financing	Debt-equity mix Senior debt: Diamond Bank (Nigeria) and Stanbic IBTC Bank (Nigeria) Subordinated debt: IFC, EIB, and Emerging Africa Infrastructure Fund
Technology	Open-cycle gas turbine	Security	n.a.
Value	$460 million (including gas and T&D infrastructure)	Fuel contract	Fuel supply agreement with Shell
COD	Currently being refinanced	EPC	General Electric

Source: LeBoeuf, Lamb, Greene, & MacRae 2006.
Note: COD = commercial operation date; EIB = European Investment Bank; EPC = engineering, procurement, and construction; IFC = International Finance Corporation; IPP = independent power project; MW = megawatts; PPA = power purchase agreement; T&D = transmission and distribution; n.a. = not applicable.

is a dispute with the local distribution company regarding the licensed area. The project is intended to serve primarily industrial clients, which is a demand cluster that no distributor is willing to give up; hence, tensions over the service area are ongoing. Aba claims to have a license from the NERC, but the new privatized distribution company claims to have a concession for the area and disputes Aba's claim on industrial customers.

The Aba project, initially corporate financed, was refinanced during construction. As the commercial operation date (COD) was delayed, debt built up; the banks have since taken over. While this embedded generation model has potential advantages, the project delays also reveal how distribution companies may resist IPPs cherry-picking larger customers.

Azura-Edo (Entering Construction)

Azura has been a path-breaking IPP development in Nigeria and is the first project-financed power generation project since reforms began (table 7.13). Investment costs—at $895 million for a 459 MW OCGT—are high and reflect perceptions of risk. The counterparty of the PPA is the newly created NBET, which has insufficient liquidity and is dependent on revenue flows from newly privatized distribution companies that are still experiencing high losses and insufficient collections. Development costs have been high. Each contract has had to be negotiated from scratch. With Azura being the first IPP in several years, there was no ready-made template to follow, and capacity had to be built among

Table 7.13 Overview of Azura-Edo, an Independent Power Project, Nigeria

Plant	Azura-Edo IPP	Contract details	20-year PPA with NBET
Location	Benin City, Edo State		
Capacity	459 MW		
Ownership	Azura-Edo Ltd. (Mauritius) (97.5%) and Edo State Government (2.5%)	Financing	$180 million equity (20%) $715 million debt 15 debt providers, including DFIs, for example, IFC, FMO, and commercial banks Main equity sponsors: Azura-Edo Ltd., 97.5%, comprising APHL, 50% (Amaya Capital 80%, American Capital 20%); AIM, 30%; ARM, 6%; Aldwych, 14%; and Edo State, 2.5%
Technology	Siemens open-cycle gas turbine	Security	Credit Enhancement PRG (IBRD) Partial Risk Guarantee, Debt (IBRD) Political risk insurance (MIGA)
Value	$895 million	Fuel contract	15-year fuel supply agreement with Seplat with a gas supply LC
Financial close	2015	EPC	Siemens and Julius Berger Nigeria

Source: Compiled by the authors from various primary and secondary sources.
Note: DFI = development finance institution; EPC = engineering, procurement, and construction; FMO = Netherlands Development Finance Company; IBRD = International Bank for Reconstruction and Development; IFC = International Finance Corporation; IPP = independent power project; LC = letter of credit; MIGA = Multilateral Investment Guarantee Agency; MW = megawatt; NBET = Nigerian Bulk Electricity Trading; PPA = power purchase agreement; PRG = partial risk guarantee.

the various stakeholders. The project sponsor is a relatively small, cash-poor, first-generation developer that had to leverage equity partners and a large number of debt providers, each of which wanted to limit its exposure. The International Finance Corporation (IFC) was a co-lead arranger of the development finance institution (DFI) component of the debt, and the World Bank employed its full range of risk mitigation instruments to make the project bankable.

The Multilateral Investment Guarantee Agency (MIGA) provided a full equity guarantee as well as a partial risk debt guarantee. The International Bank for Reconstruction and Development (IBRD) provided a credit enhancement guarantee to the NBET and commercial debt mobilization guarantees. Specifically, the IBRD PRG backstops payment obligations by the NBET, which provides security under the PPA in the form of an LC issued by a commercial bank in favor of the IPP. The LC can be drawn in the event the NBET or the government of Nigeria fails to make timely payments to the IPP. Following the drawing up of the LC, the NBET would be obligated to make a repayment to the LC bank (under the reimbursement and credit agreement), failing which the LC bank would have recourse to the IBRD PRG under the Guarantee Agreement. This in turn would trigger the obligation of the federal government of Nigeria under the indemnity agreement.

The commercial debt PRG provides direct support to commercial lenders in the event of a debt payment default caused by the NBET's failure to make undisputed payments under the PPA, or the government's payments under a termination of the PPA. There is also an LC for gas supply.

The Azura-Edo IPP deal reached a significant milestone in 2014 with the signing of key project documents and the finalization of debt arrangements; however, financial close was delayed until 2015 by the government's reluctance to provide appropriate security.

Given the complexity and cost of the Azura deal, questions have been raised as to whether project-financed IPPs are worthwhile in risky environments. The counterargument is that Azura has shown the way, and that subsequent IPPs will be much easier. In a sense, the development and risk mitigation costs of Azura could be seen as spread across a large pool of IPPs currently under development. Future IPPs will be less costly to develop; hopefully, they will also require less risk mitigation.

Chinese-Funded Projects

China is one of the fastest-growing sources of funding for power projects in Africa. This section examines the three Chinese-funded deals that have reached completion in Nigeria.

Olorunsogo I

Phase I of the Olorunsogo plant was completed in 2007 (table 7.14). It was built by the Chinese EPC contractor SEPCO-Pacific Partners. The original agreement

Table 7.14 Overview of Olorunsogo I Power Plant, Nigeria

Plant	Olorunsogo I (Papalanto)
Location	Olorunsogo, Ogun State
Capacity	335 MW
EPC	SEPCO-Pacific Partners
Technology	OCGT
Value	$360 million
COD	2007

Source: Compiled by the authors from various primary and secondary sources.
Note: COD = commercial operation date; EPC = engineering, procurement, and construction; MW = megawatt; OCGT = open-cycle gas turbine.

was to have the PHCN provide 35 percent of the funding for the project, with the balance to be provided by SEPCO through vendor financing. Proceeds from the sale of electricity would then be used to repay the vendor finance and interest. The Export-Import Bank of China provided a loan of $115 million with a 6 percent interest rate, 6-year grace period, and 12-year maturity period (Premium Times 2014; AidData 2012a).

Owing to delays in completion, a shortage of gas, and a lack of funds, the PHCN defaulted on its payments to SEPCO. The Debt Management Office took over the debt and, in line with the government's privatization efforts, the plant was ceded to SEPCO through a debt-equity swap in March 2014 (Premium Times 2014).

Since its completion, the plant has been operating far below its capacity. SEPCO had identified severe gas shortages and poorly trained PHCN staff as the principal reasons for the poor performance (Business News 2011).

Omotosho I and II

The Omotosho I deal was structured the same way as Olorunsogo (table 7.15). The PHCN was supposed to fund 35 percent of the plant, with the EPC contractor (China Machinery Engineering Corporation, CMEC) funding the remaining

Table 7.15 Overview of Omotosho I and II Power Plants, Nigeria

Plant	Omotosho I	Plant	Omotosho II (NIPP)
Location	Omotosho, Ondo State	Location	Omotosho, Ondo State
Capacity	335 MW	Capacity	500 MW
EPC	China Machinery Engineering Corporation (CMEC)	EPC	CMEC
Technology	OCGT	Technology	OCGT
Value	$361 million	Value	—
COD	2008	COD	2012

Source: AidData 2012b.
Note: COD = commercial operation date; EPC = engineering, procurement, and construction; MW = megawatt; NIPP = national integrated power project; OCGT = open-cycle gas turbine; — = not available.

65 percent. The Export-Import Bank of China also provided a loan of $115 million (AidData 2012b).

As with Olorunsogo, the government could not meet its payment obligations; by September 2012, the PHCN had accrued $104 million in unpaid debt to CMEC. The PHCN ceded control of the plant to CMEC through a debt-equity swap in March 2013 (Punch 2013). Phase II of Omotosho (part of the NIPP fleet) was also awarded to CMEC, but was not funded through the Export-Import Bank of China following the previous payment defaults by the government.

Zungeru Hydropower Project

In September 2013, the Nigerian government signed a deal with two Chinese firms (China National Electric Engineering Company and Sinohydro) to build the 700 MW Zungeru hydropower plant (table 7.16). The government approved funding for 25 percent of the project, with the Export-Import Bank of China funding 75 percent with low-interest loans. The project is the largest power project in Africa to be funded with government concessional loans (This Day Live 2013a).

Table 7.16 Overview of Zungeru Hydropower Plant, Nigeria

Plant	Zungeru
Location	Zungeru, Niger State
Capacity	700 MW
EPC	CNEEC-Sinohydro Consortium
Technology	Hydropower
Value	$1,293 million
COD	2017 (expected)

Source: Compiled by the authors from various primary and secondary sources.
Note: CNEEC = China National Electric Engineering Company; COD = commercial operation date; EPC = engineering, procurement, and construction; MW = megawatts.

Another Chinese-funded project in the pipeline is the Mambilla 3,050 MW hydropower plant in Taraba State, worth $3.2 billion. Negotiations began in 2006 with a consortium made up of the China Gezhouba Group Company Limited and China Geo-Engineering Corporation (CGGC/CGC), which were awarded the EPC contract for the project. The contract was then unilaterally cancelled by the Nigerian government and awarded to Sinohydro under controversial circumstances. CGGC/CGC disputed the cancellation, and negotiations have stalled for several years (This Day Live 2014).

A New Role for Renewable Energy

The development of renewable energy would potentially be very beneficial to Nigeria; it would help diversify the country's energy mix away from thermal sources, reduce the carbon footprint of power generation, and boost the

Table 7.17 Renewable Energy Targets for 2025, Nigeria

Energy type	*Target (MW)*
Small hydro	2,000
Solar PV	500
Wind	40
Biomass	400

Source: Compiled by the authors, based on various primary and secondary source data.
Note: PV = photovoltaic.

reliability of supply. However, renewable energy has not gained acceptance and there are currently no grid-connected plants other than the three large hydropower plants.

A Renewable Energy Master Plan was released in 2006 (and updated in 2011). This identified the considerable potential for renewable energy—a market estimated to be worth $7.5 billion.

The plan includes capacity targets and an overall goal of 23 percent of electricity supplied from renewables by 2025 (table 7.17) and 36 percent by 2030. Furthermore, the plan implements a set of incentives to support renewable energy development: in the short term, a moratorium on import duties for renewable energy technology, and in the longer term, further tax credits, capital incentives, and preferential loan opportunities (REEEP 2014). The latest MYTO also included a set of feed-in tariffs (FiTs) for renewable energy.

A number of unsolicited applications for licenses from the NERC and PPA contracts from the NBET involve renewable energy technologies, in particular solar photovoltaic (PV). Following its Procurement Regulations, the NERC has provided the NBET with a list of projects in the pipeline for which specific exemptions would be granted from the requirement to run competitive tenders for new generation capacity. Accordingly, the NBET is in direct negotiations with a number of these projects. The NBET is also doing preparatory work to run competitive tenders in the future.

Conclusions

Nigeria is in the middle of the most ambitious power sector reform process in Africa. It has unbundled generation and distribution utilities, and separated them from the TCN. It has privatized all of its distribution companies and most of its generating companies. The publicly owned NIPP generation plants are in the process of being sold. It has established a TEM with contracts between distribution companies and the bulk trader (NBET) and between generators and the NBET. And it has an independent electricity regulator. No other African country has journeyed as far as Nigeria in power sector reforms. None has fully unbundled and privatized and embarked on a contract market that will eventually lead to wholesale competition. (Uganda comes the closest: it also unbundled generation, transmission, and distribution, but it has awarded private concessions rather than selling assets and does not envisage wholesale competition.)

Nigeria's reform path has been far from smooth. It has taken time to translate into reality the restructuring vision and model embodied in the National Electric Power Policy (2001), the EPSRA (2005), and the Roadmap for Power Sector Reform (2010, 2012). But against all odds, Nigeria has made progress, aided by a clear road map and high-level support from the president and the PACP and PTFP. Individual institutions have also played their role in driving the reform forward: the BPE, for example, has driven the privatization process, albeit with assistance from transaction advisers and the Nigeria Infrastructure Advisory Facility, funded by the Department for International Development (DfID), which continues to provide extensive professional support across the sector.

The challenges and risks have been formidable. It is remarkable that generation and distribution assets were sold without the activation of the TEM and without sufficient revenue flowing from customers (through distribution companies) to the market operator—and on to generation companies and gas suppliers. Each new step along the reform path has prompted new issues that have required further interventions. Nigeria has not waited for all steps to be clearly defined and agreed upon before moving. Rather, the "Nigerian way" has been to catalyze a strong momentum for reform that becomes difficult to reverse and that forces political decisions and interventions along the way.

The journey has not been without obstacles. It was not clear whether the purchasers of assets would be able to make final payments (they did). Unions raised their voice before the assets were handed over. Concerns about unresolved conditions and financial sustainability delayed the activation of the TEM for more than a year after the target launch date (but it has since been launched). And poor billing and revenue collection, liquidity constraints, and mounting debt threatened the financial viability of the sector (but a bold intervention by the CBN helped keep the privatized companies afloat, and contracts are being activated). It is not clear if the "Nigerian way" will sustain the reforms. Election-related pressure to reduce tariffs did not help, and financial sustainability has yet to be demonstrated; also, it remains to be seen whether the momentum for reform will be maintained after the 2015 elections.

Despite reform efforts, meanwhile, Nigeria has not been able to attract sufficient investment in power generation capacity. The largest source of new generation to date has been public funding for the NIPPs, which are now in the process of being privatized. There have also been significant amounts of investment in IPPs. Indeed, excluding South Africa, Nigeria has more privately funded megawatts than any other country of Sub-Saharan Africa. These are not all traditional project-financed IPPs: two are funded by IOCs. Data presented earlier show that the performance of IPPs has been superior to state-owned generation plants; IPPs' more reliable gas supply probably contributes to the difference.

Interestingly, the first wave of IPP investments preceded power sector reform. And the most recent IPP power purchase contracts were signed during a period of financial uncertainty. Incomplete reform and financial shortfalls in the sector have not blocked IPP investments. However, not many countries would have been able to divert massive financial allocations (in Nigeria's case, from oil revenues) to keeping electricity companies afloat. Without serious efforts to achieve financial sustainability in the industry, private investments will be at risk.

IPPs have entered the sector either through limited bids (for example, the IOCs) or as a result of directly negotiated contracts; price outcomes have not been optimal. Details of PPAs have not been made available, and hence it is difficult to make definitive conclusions around comparative prices. It should be noted, however, that the directly negotiated Enron/AES Barge has been the most controversial project and the contract had to be renegotiated.

It looks likely that IOCs are once again interested in IPP investments in Nigeria, mainly to monetize domestic gas resources. ExxonMobil's project is well advanced, and may be followed by others. Nigeria will need to make sure that it is able to negotiate more competitively priced PPAs than in the previous era of IPPs.

The directly negotiated Azura project also looks expensive. However, Azura has been a trailblazer in negotiating the current terrain for IPPs. None of the previous IPPs, negotiated and contracted in a different era, offered a model that could be emulated. The project developers for Azura had to craft contracts from scratch and had to build understanding among a new generation of government, regulatory, and bulk trader officials on the risk mitigation requirements for project finance. A large proportion of Azura's costs went into these efforts, which will hopefully be beneficial for subsequent IPPs, even those that might be competitively bid.

Nigeria does not yet have a benchmark for international competitive bids (ICBs) versus directly negotiated projects. However, the NERC has mandated competitive tenders through its Regulations for the Procurement of Generation Capacity, published in 2014. It is hoped that the NBET will commence international competitive tenders in the near future.

It is also hoped that capacity will be built for effective generation planning, and that the system operator will issue regular demand and supply forecasts that will trigger initiatives to procure new capacity. The lack of such forecasts has been a weakness of the Nigerian power sector. Regular and dynamic generation expansion plans—linked directly to competitive procurement and effective contracting—are needed.

Also noteworthy in Nigeria has been the entry of Asian power investors—in the form of Korea's KEPCO and also the Chinese EPC contractors, which later took over ownership in debt-equity swaps. Chinese-funded investment in power is on the rise across the continent. Traditional government-to-government loan deals are being supplemented by Chinese participation in special-purpose project vehicles (SPVs) and in joint ventures. And Chinese EPCs are starting to take equity positions in projects. More work needs to be done to unpack the terms and outcomes of these projects.

Nigeria does not yet have any grid-connected renewable energy projects (other than hydropower), but there are a number of solar PV projects in the pipeline that are being negotiated by the bulk trader, NBET. Initial indications are that these prices might be higher than in other African countries, in part because of the lower solar resources, but also, no doubt, because of country and sector risk. Preparatory work is being done for competitive bids for renewable energy. In a few years' time it will be worthwhile to compare their price outcomes with those of directly negotiated projects. Some of these projects are also being considered for support by the World Bank PRGs.

Considerable challenges remain, and the financial sustainability of the sector is still uncertain. Not all contracts are in force. It remains to be seen whether Nigeria's power sector reforms will accelerate investment so that the country's huge power needs might be met.

What are the lessons for other African countries? Clearly, the extensive power sector reforms in Nigeria have not been a panacea. Few other African countries have sought to completely unbundle and privatize their entire electricity sector, and none have set up a wholesale electricity trader. Nevertheless, Nigeria has demonstrated that it is possible to attract IPPs in a challenging investment climate. Here, IPPs have not only been built more quickly than publicly funded projects but have resulted in superior performance. The poor financial performance of Nigeria's distribution companies, and the insecurity of gas supplies, has added risk to new IPP investments—risks that have had to be mitigated through extensive credit enhancement and security measures. Other African countries with risky investment climates can learn from what was required in Nigeria, but, hopefully, the extent and cost of these risk mitigation instruments might fall over time as the financial sustainability of the sector improves. And here lies a key lesson: ultimately, IPP investments rely on secure revenue flows from customers and distribution companies. There is no way to avoid the fundamental challenge of improving the technical and commercial performance of electricity distribution utilities. Indeed, the future success of Nigeria's power sector reforms and investment program depends on it.

Notes

1. These included five of the original unbundled generation companies with the addition of Geregu I, commissioned in 2007. The Egbin negotiation was handled separately.
2. MYTO-2 for the period up to 2017, as presented later in the text.
3. Million standard cubic feet (oil industry).
4. The highest recorded peak generated was 4,517 MW on December 23, 2012, although this may have since been superseded.
5. These plants are often referred to as IPPs as the federal government does not own them. However, they are still publicly owned by the states in which they operate.
6. The U.S. Energy Information Administration's definition is "the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period."
7. Taking into account inflation, gas prices, foreign exchange (FOREX) rates, and actual daily generation capacity.

8. A comprehensive review of all assumptions in the MYTO model.
9. The LRMC calculates the full life-cycle cost of the most efficient new generator, considering the current costs of the plant and equipment, return on capital, operation, maintenance, fuel, and so on.
10. Electricity (Amendment) Decree 1998 and the NEPA (Amendment) Act 1998.

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CHAPTER 8

Case Study 3: Investment in Power Generation in South Africa

Introduction

South Africa is a latecomer in introducing private investment and independent power projects (IPPs) into its electricity sector. For nearly a century, its national electricity utility, Eskom, dominated the power market. Various attempts to introduce IPPs were halfhearted and unsuccessful. However, this has changed during the past four years.

South Africa now occupies a central position in the global debate about how best to accelerate and sustain private investment in renewable energy. In 2009, the government began exploring feed-in tariffs (FiTs) for renewable energy, but these were rejected in favor of competitive tenders. The resulting program, known as the Renewable Energy Independent Power Project Procurement Programme (REIPPPP), has successfully channeled substantial private sector expertise and investments into grid-connected renewable energy in South Africa at competitive prices.

To date, 92 projects have been awarded to the private sector, and the first projects are already online. Private sector investments of more than $19 billion have been committed for projects that total 6,327 megawatt (MW) of renewable energy. Prices of renewable energy dropped during the four bidding phases, with average solar photovoltaic (PV) tariffs decreasing by 71 percent and wind dropping by 48 percent in nominal terms. Most impressively, these achievements occurred during a four-year period, from 2011 to 2015. Additionally, there have been notable improvements in economic development that have primarily benefitted rural communities. Important lessons can be learned from this process for both South Africa and other emerging markets contemplating investments in renewable energy and other power sources.

Table 8.1 South Africa: An Overview

Population	52.98 million (2013)	Generation capacity	45 GW
Gross domestic product	$350.6 billion (2013)	Electricity production	256,100 GWh
Income level	Upper middle income	Electricity intensity (consumption per capita)	4,694 kWh per capita
Area	1,219,912 km^2		
		Primary electricity source	Coal (90%)

Sources: World Bank, Energy Information Administration, and Eskom.
Note: GW = gigawatt; GWh = gigawatt-hour; km^2 = square kilometer; kWh = kilowatt-hour.

South Africa's Electricity Sector: An Overview

Until recently, South Africa was Africa's largest economy.[1] Its electricity generation amounts to more than half of the 80 gigawatts (GW) of installed capacity in Sub-Saharan Africa. Table 8.1 and map 8.1 list further information about South Africa's population and electricity supply.

Structure of South Africa's Electricity Supply Industry

South Africa's electricity supply industry is dominated by the state-owned and vertically integrated utility, Eskom (figure 8.1). With a capacity of approximately 42 GW, Eskom generates approximately 96 percent of South Africa's electricity. Private generators contribute approximately 3 percent of national output, and municipalities contribute an additional 1 percent.

South Africa is largely self-sufficient in electricity production. Although Eskom imports some power from nearby regions, notably Mozambique, it sells electricity to neighboring countries, including Botswana, Lesotho, Mozambique, Namibia, Swaziland, Zambia, and Zimbabwe.

Eskom owns and controls the high-voltage national transmission grid and supplies approximately half of the electricity generated directly to customers. The other half is distributed through 179 municipalities. They buy bulk supplies of electricity from Eskom, although some generate small amounts to sell within their own areas of jurisdiction. Twelve of the largest municipalities account for approximately 80 percent of the electricity distributed by all of South Africa's municipalities.

The electricity sector is overseen by the Department of Energy (DoE, formerly the Department of Minerals and Energy), and Eskom is governed by a shareholder compact with the Department of Public Enterprises (DPE). The National Energy Regulator of South Africa (NERSA) is responsible for regulating the electricity sector through approving tariffs and licensing electricity generators, transmitters, distributors, and traders.

Power Sector Reform in South Africa

Two areas have been the focus of reform efforts in South Africa's power sector during the past two decades: restructuring the fragmented electricity distribution industry, and unbundling Eskom to facilitate private investments in electricity generation. Neither has seen much progress.

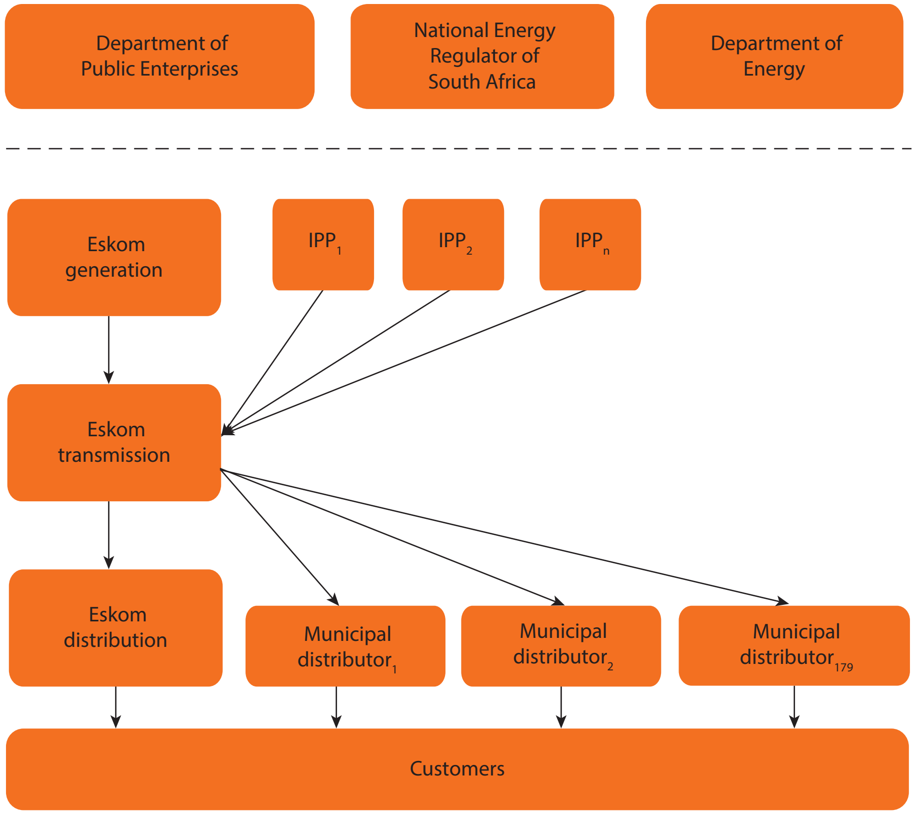
Map 8.1 Eskom's Power Stations

Source: Eskom.

Electricity Distribution Reform

South Africa's constitution grants local governments the right and responsibility to reticulate electricity; however, by the 1990s the power sector was proving to be increasingly inefficient. In 1992, discussions about reforming the electricity distribution industry began at an electricity conference hosted by the African National Congress. In the years following this conference, a number

Figure 8.1 Structure of South Africa's Electricity Market



Note: IPP = independent power project.

of stakeholder forums were established, including the National Electrification Forum, followed by the Electricity Working Group and later the Electricity Restructuring Inter-Departmental Committee. This work culminated in the PricewaterhouseCoopers Restructuring Blueprint Report and a number of cabinet decisions to reorganize the numerous municipal distributors and Eskom's distribution regions into six adequately resourced regional electricity distribution companies (REDs).

In 2004, the government established Electricity Distribution Industry (EDI) Holdings Ltd. to implement these mergers. But despite years of talk, studies, and cabinet decisions, very little progress was made toward establishing the REDs. In the end, the government accepted that a constitutional amendment was unlikely, and thus in 2010 the cabinet decided to abandon the RED model and disband EDI Holdings.

Restructuring Eskom

In the mid-1990s, the government adopted a program of self-imposed structural adjustment. Following a period of attention to macroeconomic reforms, the emphasis moved to microeconomic reforms, including a new focus on improved efficiencies and governance in government-owned entities. In 2000, the DPE published "Policy Framework: An Accelerated Agenda towards the Restructuring of State Owned Enterprises." The Eskom Conversion Act of 2001 followed. Consequently, Eskom became a state-owned public corporation subject to the Companies Act. Eskom, along with other state-owned enterprises, had to pay taxes and dividends and was subject to a shareholder performance contract.

The cabinet also approved a white paper on energy policy, released in December 1998, with the objective of achieving improvements in social equity, economic competitiveness, and environmental sustainability. The paper emphasized the importance of allowing customers to choose their electricity supplier; introducing competition into the industry, especially in the generation sector; unbundling Eskom; permitting open, nondiscriminatory access to the transmission system; encouraging private sector participation; and establishing an independent regulator. Although an electricity regulator (NERSA) was established, few of these other proposals were implemented.

After 2000, consultants were hired to design a power market for South Africa not dissimilar to Nord Pool in Scandinavia, which has a day-ahead power exchange, a bilateral contract market, and financial hedging instruments. But in 2004, worried about looming power shortages, South Africa's government abandoned these reforms as well and again placed the responsibility for new investments in power on Eskom.

A decade later, more modest reform proposals surfaced in the Independent System and Market Operator (ISMO) Bill, which was approved by the cabinet and passed by the Parliament of South Africa's Energy Committee in March 2013. The objective of the bill was to remove potential conflicts of interest in Eskom as a buyer and seller of electricity. The bill called for the establishment of a publicly owned system operator (separate from Eskom) that would be responsible for system operations and purchasing electricity from the utility and privately owned generators. Under the bill the transmission network would remain an asset of Eskom. However, the ISMO bill has been repeatedly delayed in the parliament, and it is unclear when or whether it will be reintroduced.

Power Sector Planning, Allocation, Procurement, and Contracting

South Africa has a well-defined, although quite rigid and *dirigiste*, electricity planning and procurement system. Until 2006, Eskom assumed sole responsibility for electricity planning and procuring new generation capacity. The Electricity Regulation Act (No. 4 of 2006) changed this by giving responsibility to the minister of energy to produce regular Integrated Resource Plans (IRPs) that guide electricity generation investments. In practice, Eskom's staff still produce the IRPs, but they do so now under the guidance and approval of the minister of energy.

Pursuant to the Electricity Regulation Act, the minister of energy published the Electricity Regulations on New Generation Capacity in 2009 and revised them in 2011. The regulations apply only to the public procurement of power.

Section 4(1) of the regulations states that the minister of energy, after consulting with the regulator, shall develop an IRP and publish it in the *Government Gazette*. In addition, in consultation with the regulator, the minister of energy may make various determinations about new generation capacity, including whether it is necessary, what types should be procured, how much is needed, and who the buyer should be. The minister can require that it be procured through a tendering process that is fair, equitable, transparent, competitive, and cost-effective, and it can determine whether new capacity should be provided by Eskom, another state entity, or private power projects (Electricity Regulation Act, Sec. 46 [1], 2006; Electricity Regulations on New Generation Capacity, 2011). The public procurement principles of “fair, equitable, transparent, competitive, and cost-effective” are embedded in Section 217 of South Africa’s constitution and are repeated in the Public Finance Management Act (No. 1 of 1999). The regulations also stipulate that power purchase agreements (PPAs) should reflect current costs and provide value for money.

Applicants for generation licenses have to provide evidence of compliance with the IRP or reasons for any deviations. The regulator can license only generation capacity that is envisaged in the plan and for which the minister has issued a “determination,” although the minster is empowered to grant exemptions from the plan when they are justifiable (Electricity Regulation Act, Sec. 11, 2006).

The IRP 2010–30 was gazetted in 2011 and is summarized in table 8.2.

The first determination under these regulations on new generation capacity was gazetted by the minister of energy in 2011 and was for 3,725 MW of grid-connected renewable energy. A further ministerial determination was made in 2012 for 2,500 MW of power from coal, 2,652 MW from gas, 2,609 MW from hydropower, 800 MW from cogeneration, and an additional 3,200 MW from renewable energy. The IRP was updated in 2013 to include lower demand forecasts, more gas, and less nuclear power; however, the updated plan has not yet been officially adopted. In 2015, the minister of energy determined that an additional 6,300 MW of renewable energy should be procured.

These ministerial determinations have initiated a quiet revolution in South Africa’s power sector. In each case, the minister has stipulated that new capacity should be provided by IPPs rather than Eskom. Competitive tenders have been issued for renewable energy (described ahead) and coal, and subsequent tenders are planned for cogeneration and gas.

Eskom

Installed Capacity

Eskom’s baseload generation capacity comprises several large coal-fired power stations situated in the northeast of the country and a single nuclear power station on the west coast. Diesel-fired gas turbines and pumped-storage schemes supply Eskom’s peaking capacity. A breakdown of its generation capacity is shown in table 8.3 and figure 8.2.

Table 8.2 South Africa's Integrated Resource Plan, 2010–30

	New build options								*Committed*					*Non-IRP*
	Coal (PF, FBC, imports, own build)	*Nuclear*	*Import hydro*	*Gas–CCGT*	*Peak–OCGT*	*Wind*	*CSP*	*Solar PV*	*Coal*	*Other*	*DoE Peaker*	*Wind*	*Other renewables non-IRP*	*Cogeneration*
Year	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2010	0	0	0	0	0	0	0	0	380	260	0	0	0	0
2011	0	0	0	0	0	0	0	0	679	130	0	0	0	0
2012	0	0	0	0	0	0	0	300	303	0	0	400	100	0
2013	0	0	0	0	0	0	0	300	823	333	1,020	400	25	0
2014	500	0	0	0	0	400	0	300	722	999	0	0	100	0
2015	500	0	0	0	0	400	0	300	1,444	0	0	0	100	200
2016	0	0	0	0	0	400	100	300	722	0	0	0	0	200
2017	0	0	0	0	0	400	100	300	2,168	0	0	0	0	200
2018	0	0	0	0	0	400	100	300	723	0	0	0	0	200
2019	250	0	0	237	0	400	100	300	1,446	0	0	0	0	0
2020	250	0	0	237	0	400	100	300	723	0	0	0	0	0
2021	250	0	0	237	0	400	100	300	0	0	0	0	0	0
2022	250	0	1,143	0	805	400	100	300	0	0	0	0	0	0
2023	250	1,600	1,183	0	805	400	100	300	0	0	0	0	0	0
2024	250	1,600	283	0	0	800	100	300	0	0	0	0	0	0
2025	250	1,600	0	0	805	1,600	100	1,000	0	0	0	0	0	0
2026	1,000	1,600	0	0	0	400	0	500	0	0	0	0	0	0
2027	250	0	0	0	0	1,600	0	500	0	0	0	0	0	0
2028	1,000	1,600	0	474	690	0	0	500	0	0	0	0	0	0
2029	250	1,600	0	237	805	0	0	1,000	0	0	0	0	0	0
2030	1,000	0	0	948	0	0	0	1,000	0	0	0	0	0	0
Total	**6,250**	**9,600**	**2,609**	**2,370**	**3,910**	**8,400**	**1,000**	**8,400**	**10,133**	**1,722**	**1,020**	**800**	**325**	**800**

Source: DoE 2011.
Note: CCGT = combined-cycle gas turbine; CSP = concentrated solar power; DoE = Department of Energy; FBC = fluidized bed combustor; IRP = Integrated Resource Plan; MW = megawatt; OCGT = open-cycle gas turbine; PF = pulverized coal-fired boiler; PV = photovoltaic.

Table 8.3 Eskom's Electricity Generation Capacity: South Africa, 2014

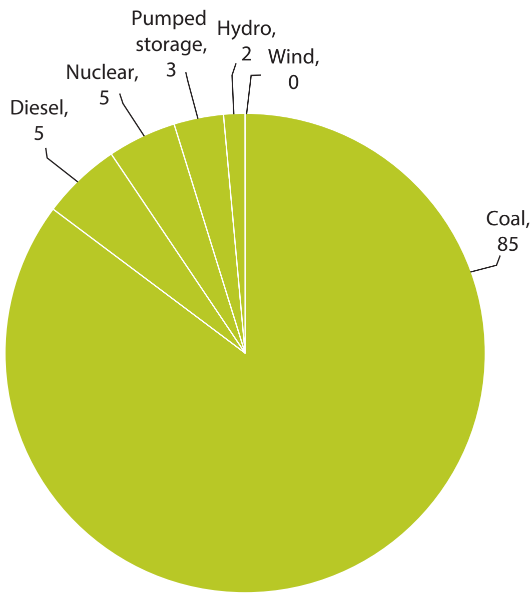
Technology and plant	*Location*	*Capacity (MW)*
Coal		
Arnot	Middelburg, Mpumalanga	2,232
Camden	Ermelo, Mpumalanga	1,481
Duvha	Witbank, Mpumalanga	3,450
Grootvlei	Balfour, Mpumalanga	1,120
Hendrina	Hendrina, Mpumalanga	1,798
Kendal	Witbank, Mpumalanga	3,840
Komati	Middelburg, Mpumalanga	904
Kriel	Kriel, Mpumalanga	2,850
Lethabo	Sasolburg, Free State	3,558
Majuba	Volksrust, Mpumalanga	3,843
Matimba	Ellisras, Limpopo	3,690
Matla	Kriel, Mpumalanga	3,450
Tutuka	Standerton, Mpumalanga	3,510
Nuclear		
Koeberg	Melkbosstrand, Western Cape	1,860
Conventional hydro		
Gariep	Norvalspont, Free State	360
Vanderkloof	Petrusville, Northern Cape	240
Pumped storage		
Drakensberg	Bergville, KwaZulu Natal	1,000
Palmiet	Grabouw, Western Cape	400
Diesel-fired gas turbines		
Acacia	Cape Town, Western Cape	171
Ankerlig	Atlantis, Western Cape	1,327
Gourikwa	Mossel Bay, Western Cape	740
Port Rex	East London, Eastern Cape	171
Eskom total nominal capacity		**41,995**

Source: Eskom 2014.

Capacity Additions

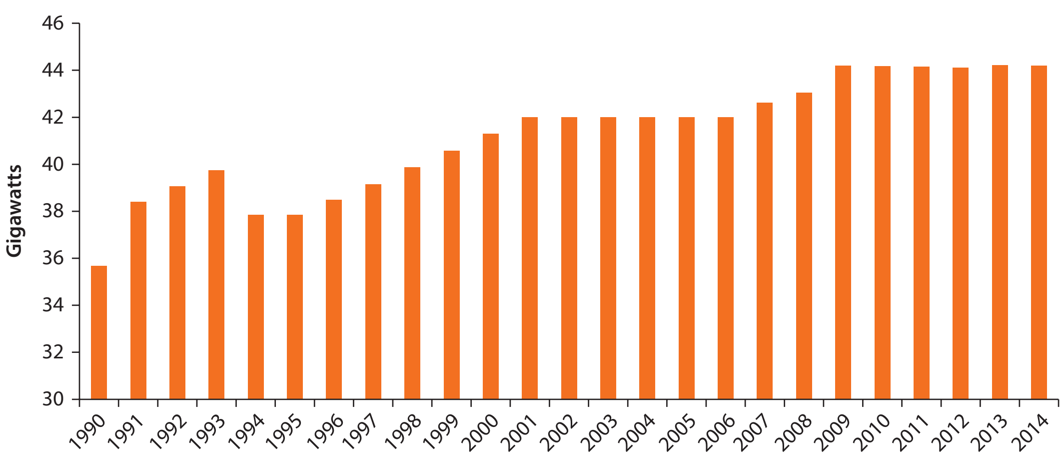
Much of Eskom's current generation capacity was built in the 1970s and 1980s in a massive investment program that ultimately resulted in overcapacity and the subsequent mothballing of three of its older power stations. After 2001, when a competitive market was being designed, the government prohibited Eskom from building any new capacity in the hope of attracting private investments in generation. However, the new power market was never implemented, and no procurement or contracting mechanisms were put in place for IPPs. By 2004, the government was concerned that power reserve margins were diminishing, and the responsibility for investing in new capacity was again placed on Eskom. Eskom began by refurbishing the three mothballed power stations, followed by investing in new diesel-fired open-cycle gas turbines (OCGTs) and later new

Figure 8.2 Eskom's Electricity Generation Mix: South Africa, 2014
percent



Source: Constructed from Eskom 2014.

Figure 8.3 Eskom's Installed Generation Capacity over Time: South Africa, 1990–2014



Source: Eskom's annual reports.

coal-fired stations. However, despite these efforts, demand exceeded supply, and nationwide power cuts commenced in 2008 and are now a regular occurrence. Eskom's installed generation capacity over time and recent additions are shown in figure 8.3 and table 8.4, respectively.

Eskom is embarking on a capital expansion program that costs an estimated $35 billion and will include the addition of two 4,800 MW coal-powered plants

Table 8.4 Eskom's Recent Generation Capacity Additions: South Africa, 2006–13
megawatts

Plant	*Technology*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*
Camden[a]	Coal	190	740	320	190	n.a.	n.a.	n.a.	n.a.
Grootvlei[a]	Coal	n.a.	n.a.	190	190	380	190	140	n.a.
Komati[a]	Coal	n.a.	n.a.	n.a.	170	n.a.	125	300	200
Ankerlig	OCGT	n.a.	440	150	735	n.a.	n.a.	n.a.	n.a.
Gourikwa	OCGT	n.a.	145	300	300	n.a.	n.a.	n.a.	n.a.
Total		**190**	**1,325**	**960**	**1,585**	**380**	**315**	**440**	**200**

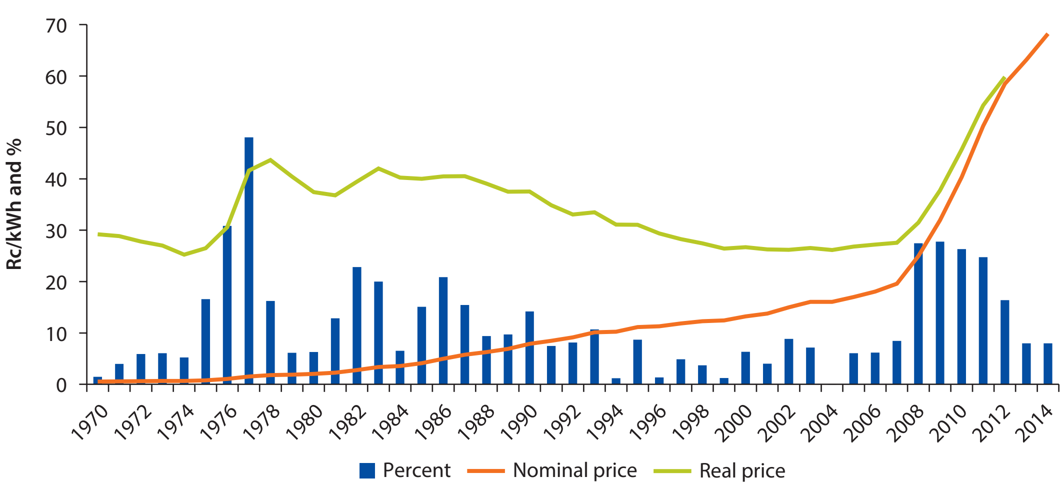
Source: Eskom's annual reports.
Note: OCGT = open-cycle gas turbine; n.a. = not applicable (no capacity additions).
a. Returned to service.

(Medupi and Kusile), a 1,332 MW pumped-storage scheme (Ingula), and two 100 MW renewable energy plants (Eskom 2014). However, at present these projects are late and over budget. Construction on the coal-powered plants started in 2007–08 and should have been completed by 2014. Instead, the first unit came online only in 2015, and the two power stations will be completed in 2021 at the earliest.

Eskom Costs, Prices, and Funding

Eskom's prices are regulated by NERSA in multiyear price determinations (MYPDs) based on a rate-of-return methodology. Historically, the major cost driver for Eskom has been capital expenditures on new electricity generation capacity. Figure 8.4 demonstrates how prices escalated sharply in the 1970s and 1980s, when most of Eskom's current electricity generation fleet was built, and

Figure 8.4 Eskom's Average Prices (Rc/kWh) and Annual Increases (%): South Africa, 1970–2014



Source: Authors' compilation, based on Eskom's annual reports and consumer price indexes.
Note: kWh = kilowatt-hour; Rc = rand cent.

again in recent years as Eskom builds new power stations. Current average Eskom electricity prices are between U.S. cents (USc) 6/kilowatt-hour (kWh) and USc 7/kWh. The marginal cost of its new coal-powered stations will be much higher than this, likely close to USc 10/kWh.

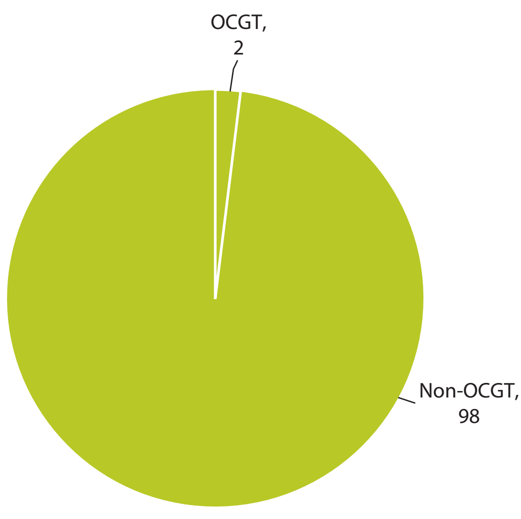
The budgets for Medupi, Kusile, and Ingula have more than doubled, and the interest accruing during construction is escalating amid ongoing construction delays. Eskom's initial estimate for Medupi in October 2007, when construction began, was South African rand (R) 78.6 billion, including the interest expected during construction. By July, Eskom had revised its estimate to R105 billion, excluding interest during construction, which could amount to an additional R 35 billion. If flue gas desulphurization is added, the total cost could exceed R 150 billion.

Until the first units from Medupi start supplying energy to the grid, reserve margins will remain tight. To provide regular electricity to its customers, Eskom must run its costly peaking plants at much greater load factors than budgeted. The total outlay for the OCGT stations for fiscal year (FY) 2013/14 was R 10.6 billion (2012/13: R 5.0 billion), significantly over the original budget (Eskom 2014). These breakdowns are shown in figure 8.5 and figure 8.6.

Eskom's coal costs have been rising. Historically these were low because most of Eskom's coal was supplied by tied mines on long-term, cost-plus contracts. However, some of the original contracts have ended, or will do so soon, and Eskom is increasingly exposed to short-term contracts at higher prices. Average coal costs are currently approximately R 350/ton ($30/ton).

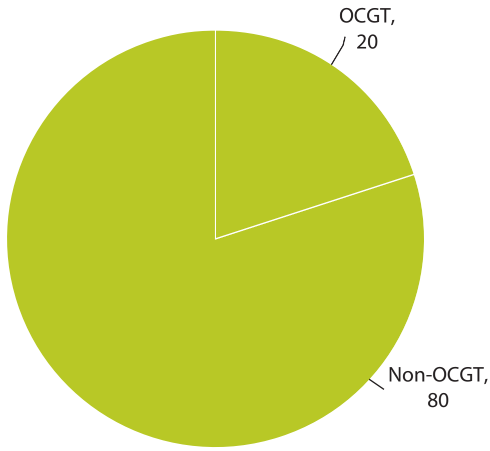
Eskom's performance has been deteriorating amid increased plant outages. The precipitous decline in average power station capacity factors in recent years

Figure 8.5 Proportion of Eskom's Electricity Generated by OCGTs: South Africa, FY2013/14
percent



Source: Constructed from Eskom 2014.
Note: FY = fiscal year; OCGT = open-cycle gas turbine.

Figure 8.6 Proportion of Primary Energy Costs Attributed to OCGTs: South Africa, FY2013/14
percent



Source: Constructed from Eskom 2014.
Note: FY = fiscal year; OCGT = open-cycle gas turbine.

Figure 8.7 Average Availability of Generation Plants Run by Eskom: South Africa, 2000–15

Source: Eskom's annual reports.
Note: Unit capacity factor is defined as the amount of electricity generated by a power unit or power station throughout a specified time period, divided by the maximum amount of electricity that the plant could have generated during that period—that is, the installed capacity multiplied by the number of hours in that period, expressed as a percentage.

is noticeable in figure 8.7. The years of insufficient spending on maintenance are now beginning to take their toll.

For most of its history, Eskom has raised debt from private capital markets to fund its capital expenditure programs. It received government support for the first time in 2008 with a subordinated loan of R 10 billion, followed by R 30 billion in 2009 and R 20 billion in 2010. These loans were converted to equity in 2015. Nevertheless, Eskom's balance sheet does not look promising. Eskom applied for annual tariff increases of 16 percent, but NERSA's MYPD3 awarded only 8 percent increases annually from 2013/14 to 2017/18. The regulator accepted additional costs through an adjustment to the regulatory clearing account that resulted in an additional 5 percent increase in 2014/15, but it declined an additional application from Eskom in May 2015 for a selective reopening of some cost items. The government promised an additional injection of R 23 billion in 2015, raised from asset sales, but Moody's and Standard & Poor's (S&P) downgraded Eskom's credit rating to junk status.

As part of the funding for Medupi, Eskom, with the support of the government, sought a $3.75 billion loan from the World Bank. This was the World Bank's first financial support to South Africa since the end of apartheid. Part of the loan will also fund Eskom's first wind farm, the 100 MW Sere Wind Farm, as well as a proposed 100 MW concentrated solar power (CSP) plant (World Bank 2012). The loan was approved in 2010.

Eskom's financial situation is deteriorating sharply. It is facing a liquidity squeeze as its costs rise and sales volume stagnates. And the cost and difficulty of raising sufficient debt financing is challenging.

Other Electricity Generation Providers in South Africa

Prior to 2011, South Africa had very limited success in procuring independent electricity generation. Several negotiations with international and local IPPs stalled, and Eskom's procurement programs were abandoned or secured only marginal amounts of power. This included projects under the Short-Term Power Purchase Programme (STPPP), the Medium-Term Power Purchase Programme (MTPPP), the Wholesale Electricity Pricing System (WEPS), and municipal baseload contracts. These proportions are shown in table 8.5 and figure 8.8.

Privatization

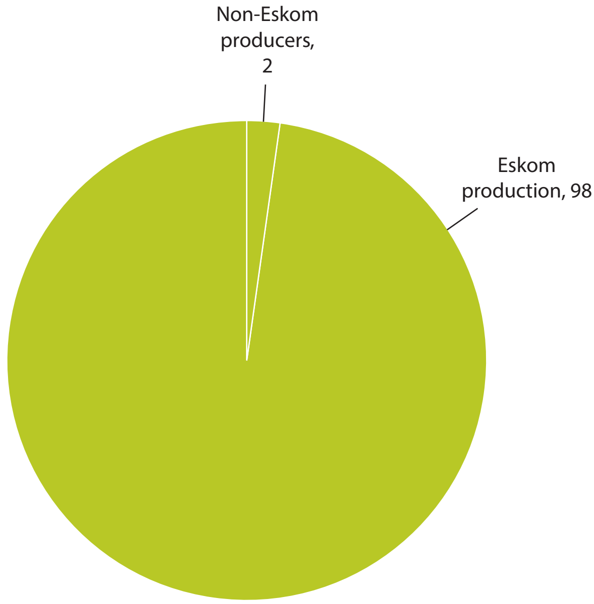
South Africa's first attempt to invite private participation in the electricity sector was the privatization of the Kelvin 600 MW coal-powered plant in 2001 by the City of Johannesburg. The U.S.-based AES acquired a 95 percent majority share

Table 8.5 Eskom's Energy Purchases from Other Generators: South Africa, FY2013/14

Source	*Energy (GWh)*	*Cost (Rc/kWh)*
MTPPP	1,478	82
STPPP	931	88
WEPS	139	52
Municipal baseload	873	88

Source: Eskom 2014.
Note: FY = fiscal year; GWh = gigawatt-hour; kWh = kilowatt-hour; MTPPP = Medium-Term Power Purchase Programme; Rc = rand cent; STPPP = Short-Term Power Purchase Programme; WEPS = Wholesale Electricity Pricing System.

Figure 8.8 Eskom's Energy Purchases from Other Generators: South Africa, FY2013/14
percent



Source: Eskom 2014.
Note: FY = fiscal year.

in the plant only to slip into financial difficulties following the collapse of Enron, forcing it to sell its share to Globeleq in 2002 (Business Report 2002). Globeleq retained majority ownership of Kelvin until 2006, when it was also forced to sell the plant, citing technical issues; it stated that the plant could not be brought back to its full capacity, making it financially unviable. Globeleq relinquished the asset to Nedbank and Investec, which had originally financed the deal (Benjamin 2006).

In 2007, a consortium of investors concluded agreements to purchase a 95 percent stake in the plant from Nedbank and Investec. Included in the consortium was an infrastructure fund managed by Old Mutual, Macquarie, Kagiso Trust, J&J Infrastructure Holdings, and Aldwych Kelvin Operations (Proprietary) Ltd. (the wholly owned South African subsidiary of Aldwych International, Ltd., which currently has a management services agreement with Kelvin Power [Proprietary] Ltd.).

The Kelvin power station has reportedly been operating at 25 percent of its capacity for several years, and is undergoing continuous refurbishment efforts to increase its capacity.[2]

Another privatization attempt was the partial privatization of the Kusile coal-powered plant, which is still under construction. In an effort to raise much-needed capital, Eskom considered selling a 30–49 percent stake. However, no privatization deal was struck. Eskom's former chief executive officer (CEO)

Brian Dames stated, "the return requirement by private investors was a lot higher than what Eskom is prepared to accept as a return" (Donnelly 2012).

International Deals

Eskom has been involved in negotiations with several international power projects, but with little result. Two of the larger projects are the Mmamabula coal-powered plant (Botswana) and the Mphanda Nkuwa hydropower project (Mozambique) (Eskom 2009). Both depend on an Eskom PPA to secure their financial viability.

The 1,200 MW Mmamabula Energy Project is an integrated coal mine and power plant project proposal from Botswana. Negotiations between Eskom and the project developer, CIC Energy Corporation, were for a 75 percent fixed off-take agreement (Eskom 2010). CIC offered power at rand cent (Rc) 72/kWh, indexed at below inflation. At the time, Eskom found it too expensive, but it is now below the cost of Medupi and Kusile, Eskom's new mega power plants currently being built.

The 1,500 MW Mphanda Nkuwa hydropower project (downriver from the Cahora Bassa hydropower scheme on the Zambesi River) has also shown little progress. Negotiations have been under way since 2008, yet no PPAs have been signed. There have reportedly been some technical and political concerns regarding the agreements. Eskom wants to minimize financial risk and takes no responsibility for the transmission failures of the Mozambican grid. It demands that it purchase power at the border, not at the point of generation, and using rand-denominated PPAs.

Other international projects in which Eskom has had limited active engagement include the Kudu gas field (Namibia), the Benga and Moatize coal-powered projects (Mozambique), and the Kariba North Bank hydropower extension (Zambia).

Since the project's inception around 2006, developers of the 800 MW Kudu gas field have tried on several occasions, with little success, to get Eskom to commit to a long-term off-take agreement. The Zambian private utility CEC Africa has now taken an equity stake in the project with an interest in concluding power purchases for the southern African region.

Eskom originally declined an offer to purchase a stake in the 600 MW Moatize coal-powered project situated in Mozambique but then expressed interest in entering into a PPA (Bloomberg Business Week 2006). The first phase (300 MW) of the project was approved in March 2014, with 250 MW to be supplied to the attached coal mine and the balance sold to Mozambique's grid. However, there is no indication that Eskom is still involved in the project.

One international project that is starting to show progress is the Inga hydropower scheme in the Democratic Republic of Congo. The project has the potential to supply up to 44 GW of electricity to the continent when it is complete, but it has been in the pipeline for more than 40 years. The next stage, Inga 3, will supply 4,800 MW. The Grand Inga Treaty between the Democratic Republic of

Congo and South Africa was signed in October 2013 and ratified by the cabinet in August 2014, but the treaty has been submitted to parliament. Under the agreement, Eskom is contractually committed to purchase 2,500 MW from Inga 3, provide 15 percent of the equity to build the plant, and build the transmission network to the border of the Democratic Republic of Congo. Furthermore, Eskom will buy at least 33 percent of all future capacity additions of the Inga project.

The Aggreko 110 MW natural gas plant based on the border of South Africa and Mozambique is one small example of a successful international negotiation, albeit a temporary one. Commissioned in 2012, the plant is the world's first international, interim IPP. It will be replaced by a longer-term, 120 MW plant being constructed by Gigawatt Global.

Sasol and EDM have also developed the 170 MW Centrale Termica Ressano Garcia in the same area. The plant has been in operation since March 2015, and it sells its output to EDM, which then sells part of it to various regional off-takers. EDM/Sasol are also developing the 400 MW Temane project, which could sell the majority of its output to Eskom.

Non-Eskom Thermal Power in South Africa

Three procurement programs that were initiated by Eskom between 2007 and 2009 had industry players optimistic that the generation market was slowly opening up. However, by 2009, despite considerable market interest, the Eskom-led programs had all been scrapped. During the same period, the DoE commenced procurement for an IPP to produce peaking power. There have been considerable delays, but the contract has been awarded and construction is under way.

Cogeneration and Short- and Medium-Term Contracts

Initiated by Eskom, the Pilot National Cogeneration Programme (PNCP), the MTPPP, and the Multisite Baseload Independent Power Project Programme (MBLIPP) all showed promise, but then they were all ultimately scrapped with little or no capacity procured.

Initiated in 2007, the PNCP sought to procure 900 MW of cogeneration capacity. Following the publication of a request for proposals (RfP), 125 bids were received that totaled 4,900 MW of potential capacity. Bids that met the minimum requirements were evaluated against a ceiling price. The price was equal to Eskom's avoided cost of generation (adjusted for the time and location of the plant). The maximum length of the PPA on offer was 15 years (Eskom 2007).

There had been considerable private sector interest in the program, yet developers were also critical. Many found that the PPA was too burdensome and placed undue risk on the generator. By its nature, cogeneration technology relies on fuel from an unpredictable industrial process, and without a fuel pass-through mechanism, bidders are exposed to fuel-supply risk (DoE 2009). Furthermore bidders struggled to beat the unrealistically low ceiling price set by Eskom (Viljoen 2008). Ultimately, no PPAs were signed, and the program was deemed a failure.

The MTPPP was initiated in 2008 in response to developers that wished to participate in the PNCP but did not qualify. The program was aimed at project sponsors with the ability to supply electricity to the grid by 2012. An RfP was published in March 2008.

Projects under the program were required to be between 5 MW and 1,000 MW and could involve any technology that included new build, incremental capacity additions, or the refurbishment of existing plants. The total capacity allowed under the program was 3,000 MW, and successful bids would be awarded a PPA with a maximum length of 10 years, ending in December 2018 (Viljoen 2008).

An improvement to the PNCP was the price band outlined in the RfP, shown in table 8.6. This allowed bidders to gauge their chance of being awarded a PPA (de Beer and Magubane 2009). Bids received that were below the ceiling price would automatically be awarded a PPA on a first-received, first-accepted basis. Bids that fell between the ceiling price and the maximum price would be evaluated against other bids (Eskom 2008).

Still, bidders again criticized the PPA on offer. Many argued that the prices did not reflect the costs to be expected near the end of the PPA term. Additionally, the short length of the PPA placed serious constraints on projects' ability to raise and pay back debt (de Beer and Magubane 2009).

Decisions about preferred bidders were delayed for several years. In February 2011, Eskom announced the procurement of six projects totaling 373 MW under the program, a far cry from the 3,000 MW target. The exact makeup of the 373 MW of capacity has not been made public, but PPAs were signed with Sasol, IPSA, Tangent Mining, and SAPPI (*Engineering News* 2011).

The PPA signed with Sasol was for 200 MW of OCGT capacity at its Secunda synthetic fuel plant. The project was an expansion of its current gas-fired plant, and it began operation in July 2010 after 21 months of construction (*Engineering News* 2010).

The PPAs signed under the MTPPP lapsed in early 2014, but have subsequently been renewed. For FY2013/14, Eskom purchased 1,478 gigawatt-hours (GWh) from IPPs under the MTPPP at an average cost of Rc 82/kWh (Eskom 2014).

Initiated in April 2008, the MBLIPP aimed to secure up to 4,500 MW of capacity from plants with a maximum size of 200 MW. IPPs were expected to come online between 2012 and 2017 and have a PPA length of up to 40 years (de Bruyn 2009). Following a request for qualification, 23 local and international bidders

Table 8.6 Medium-Term Power Purchase Programme Prices: South Africa, 2009–18
Rc/kilowatt-hour (2008)

Price parameter	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*
Ceiling price	65	65	65	65	65	60	50	40	35	35
Maximum price	105	105	105	105	105	85	75	60	40	35

Source: Eskom 2014.
Note: Rc = rand cent.

were identified, the majority of which were coal-powered plants (Kohler 2009). However, without explanation, the program was suspended along with the other two (PNCP and MTPPP) in 2009.

The Peaker Project, Department of Energy

The Peaker Project involved an international competitive bid (ICB) under the auspices of the DoE. The project followed a 2004 cabinet decision that 2,000 MW of peaking capacity was to be procured, half by the then–Department of Minerals and Energy and half by Eskom (Pickering 2011).

Two out of the five prequalified developers submitted bids for the DoE's Peaker Project in April 2007, and the contract was awarded to an AES-led consortium. The DoE had expressly excluded the project from the requirements of the Electricity Regulations on New Generation Capacity. The project would not need to be subject to a value-for-money assessment; nor was a feasibility assessment required to ascertain whether Eskom or the private sector should build the plant (Donnelly 2011). However, negotiations between the DoE and AES broke down in 2008, with neither party claiming fault (Pickering 2011). The DoE pursued the project despite criticisms that it was unnecessary because, in the meantime, Eskom's Ankerlig and Gourikwa OCGT plants had been expanded to provide more than 2,000 MW of peaking capacity.

Almost a decade after the 2004 cabinet decision, a deal was eventually signed in June 2013. The DoE entered into 15-year PPAs with a consortium led by GDF Suez to deliver electricity from two plants: one in the Eastern Cape (Dedisa) and one in KwaZulu Natal (Avon), of 335 MW and 670 MW, respectively. The combined investment value of the project is €780 million (*Engineering News* 2013b). (GDF Suez had been the only other party, besides AES, to bid on the project back in 2007.) The commercial operation date (COD) is expected to fall in FY2015/16.

Renewable Energy Independent Power Project Procurement Programme

In 2009, the government began exploring FiTs for renewable energy, but these were later rejected in favor of competitive tenders. The initial announcement of the program was through a ministerial determination in August 2011 calling for the procurement of 3,625 MW of renewable energy capacity. Another ministerial determination in 2012 added an additional 3,200 MW of capacity to be allocated between 2017 and 2020.

On August 3, 2011, an RfP was issued, and the next month a compulsory bidder's conference was held to address questions about bid requirements, documentation, PPAs, and so on. Approximately 300 organizations attended this conference. The REIPPPP envisioned the procurement of 3,625 MW of power throughout the course of a maximum of five tender rounds. Another 100 MW was reserved for small projects (below 5 MW) that were to be procured in a separate IPP program focused on small projects. Caps were set on the total capacity to be procured for individual technologies. The largest allocations were for wind and PV, with smaller amounts for CSP, biomass, biogas, landfill gas, and hydropower. The rationale for these caps was to limit the supply to be bid out and therefore increase the level of competition among the different technologies and potential bidders.

The tenders for different technologies were held simultaneously. Interested parties could bid for more than one project and more than one technology. Projects needed to be larger than 1 MW, and an upper limit was set on bids for different technologies—for example, 75 MW for a PV project, 100 MW for a CSP project, and 140 MW for a wind project. Caps were also set on the price for each technology. Bids were due within three months of the release of the RfP, and the financial close was to take place within six months after announcing the preferred bidders.

The bid evaluation involved a two-step process. In the first, bidders needed to satisfy certain minimum threshold requirements in six areas: environment, land, commercial and legal, economic development, financial, and technical. For example, wind developers were required to provide 12 months of wind data for the designated site and an independently verified generation forecast. Project developers were responsible for identifying appropriate sites and for paying for measurement and early development costs at their own risk.

The economic development requirements in particular were complex, incorporating 17 sets of minimum thresholds and targets (table 8.7). For wind projects, for example, at least 12 percent of the company shares had to be held by black South Africans and another 3 percent by local communities. At least 1 percent of project revenues had to go to socioeconomic contributions. The minimum threshold for local content was set at 25 percent, with an encouraged target of 45 percent.

Bidders that satisfied the threshold requirements then proceeded to the second step of evaluation, in which bid prices counted toward 70 percent, and the remaining 30 percent weighting was given to composite scores on job creation, local content, preferential procurement, enterprise development, and socioeconomic development. Bidders were asked to provide two prices—one fully indexed for inflation and the other partially indexed—and the bidder was allowed to determine the proportion that would be indexed.

The RfP included a standard PPA, an implementation agreement (IA), and direct agreements (DAs). The PPA was to be signed by the IPP and Eskom, the off-taker. The PPAs specified that transactions should be denominated in South African rand and that contracts would have 20-year tenures from the COD. The IAs were to be signed by the IPPs and the DoE, and effectively provided a sovereign guarantee of payment to the IPPs by being required to make good on these payments in the event of an Eskom default. The IA also placed obligations on the IPP to deliver economic development targets. The DAs provided step-in rights for lenders in the event of default. The PPA, IA, and DA were nonnegotiable contracts that were developed after an extensive review of global best practices and consultations with numerous actors in the public and private sectors. Despite some bidder reservations regarding the lack of flexibility to negotiate the terms of

Table 8.7 Economic Development Thresholds and Targets for Wind Projects in South Africa's REIPPPP
percent

Factor and criteria	*Threshold*	*Target*
Employees		
South Africa–based employees who are citizens	50	80
South Africa–based employees who are black citizens	30	50
Skilled employees who are black citizens	18	30
South Africa–based employees who are citizens from local communities	12	20
Local content		
Value of local content spending	25	45
Ownership		
Shareholding by black people in the project company	12	30
Shareholding by black people in the contractor responsible for construction	8	20
Shareholding by black people in the operations contractor	8	20
Shareholding by local communities in the project company	3	5
Management control		
Black top management	n.a.	40
Preferential procurement		
Broad-based black economic empowerment procurement spending	n.a.	60
Procurement from small enterprises	n.a.	10
Procurement from women-owned vendors	n.a.	5
Enterprise development		
Enterprise development contributions	n.a.	0.6
Adjusted enterprise development contributions	n.a.	0.6
Socioeconomic development		
Socioeconomic development contributions	1.0	1.5
Adjusted socioeconomic development contributions	1.0	1.5

Sources: Department of Energy, REIPPPP bid documents, and press releases (http://www.ipp-renewables.co.za).
Note: REIPPPP = Renewable Energy Independent Power Project Procurement Programme; n.a. = not applicable (no threshold set).

the various agreements, the overall thoroughness and quality of the standard documents seemed to satisfy most of the bidders participating in the three rounds.

Bidders had to submit bank letters indicating that financing had been secured—this was highly unusual and basically a way to outsource due diligence to the banks. Effectively, this meant that lenders took on a higher share of the project development risk, and this arrangement dealt with the biggest problem with auctions: the low-balling that results in deals not closing.

The developers were expected to identify the sites and pay for early development costs at their own risk. A registration fee of R 15,000 ($1,875) was due at the outset of the program. Bid bonds or guarantees had to be posted that were equal to R 100,000 ($12,500) per megawatt of the nameplate capacity of the proposed facilities, and the amount was doubled when the preferred bidder status was announced.[3] The guarantees were to be released when the projects came online or if the bidder was unsuccessful after the RfP evaluation stage.

In August 2011, an initial RfP was issued. By November 2011, 53 bids for 2,128 MW of generating capacity were received. Ultimately, 28 preferred bidders were selected, offering 1,416 MW, for a total investment of nearly $6 billion. Successful bidders realized that not enough projects were ready to meet the bid qualification criteria and that all qualifying bids were thus likely to be awarded contracts. Bid prices in the first round were thus close to the price caps set in the tender documents. Major contractual agreements were signed on November 5, 2012, and most projects reached full financial close shortly thereafter. Construction on all of these projects has commenced, and the first project came online in November 2013.

A second round of bidding was announced in November 2011. The total amount of power to be acquired was reduced, and other changes were made to tighten the procurement process and increase competition. Seventy-nine bids for 3,233 MW were received in March 2012, and 19 bids were ultimately selected. Prices were more competitive, and bidders also offered better local content terms. PPA, IAs, and DAs were signed for all 19 projects in May 2013.

A third round of bidding commenced in May 2013, and again the total capacity offered was restricted. In August 2013, 93 bids were received that totaled 6,023 MW. Seventeen preferred bidders were notified in October 2013, totaling 1,456 MW. Prices fell further in round 3. Local content again increased, and although some projects were delayed because of uncertainties around Eskom transmission connections, all reached financial close.

In December 2014, an additional 200 MW of CSP projects were awarded.

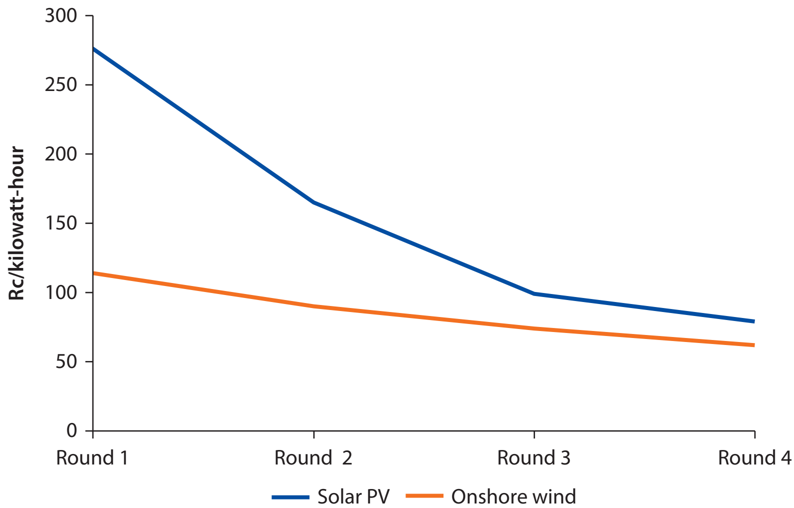
A fourth round of bidding commenced in August 2014, and preferred bidders were to be announced in November 2014. An award was eventually announced in April 2015 for 13 projects that totaled 1,121 MW. Prices were so low that an additional allocation was made in June 2015 for an additional 13 projects that totalled 1,084 MW.

To date, 92 projects have been awarded to the private sector, and the first projects are already online. Private sector investments totaling more than $19 billion have been committed, and these projects total 6,327 MW of renewable power. Prices dropped during the four bidding phases, with average PV tariffs decreasing by 71 percent and wind dropping by 48 percent in nominal terms. Most impressively, these achievements occurred during a four-year period, from 2011 to 2015 (figure 8.9). Grid-connected renewable energy prices are now among the cheapest in the world, with average solar PV prices in round 4 at USc 6.4/kWh and the cheapest wind bid at USc 4.7/kWh.

Finally, there have been notable improvements in economic development commitments that have primarily benefitted rural communities.

Real returns to equity in round 1 were close to the 17 percent (in local currency) that was envisaged when determining the original FiTs. Equity returns

Figure 8.9 Average Nominal Bid Prices in South Africa's REIPPPP



Source: Department of Energy REIPPPP office.
Note: PV = photovoltaic; Rc = rand cent; REIPPPP = Renewable Energy Independent Power Project Procurement Programme.

dipped slightly in round 2 for wind and probably more substantially for PV. Dollar returns in the range of 12–13 percent were reported. Returns fell further in round 3, especially for some of the corporate-funded projects (table 8.8).

Increased competition was no doubt the main driver for the price fall after the first round, but there were other factors as well. International prices for renewable energy equipment have declined during the past few years because of a glut in manufacturing capacity as well as ongoing innovations and economies of scale. The REIPPPP was well positioned to capitalize on these global factors. Transaction costs were also lower in subsequent rounds because many of the project sponsors and lenders became familiar with the REIPPPP tender specifications and requirements.

Figure 8.10 indicates the performance of the wind and solar PV plants that have been connected to the grid.

Fifty-six of the 64 projects in rounds 1–3 have been project financed. One project in round 1 (Touwsrivier Solar Energy Facility) issued a corporate bond valued at R 1 billion, and a small hydropower project (Stortemelk) was initially corporate financed, but it is now being refinanced through debt. Six projects out of 17 in round 3 were corporate financed, all by the Italian utility Enel (which had been unsuccessful in previous rounds). Reports indicate that returns on equity for the corporate-funded projects in round 3 were low. This trend toward corporate financing in the REIPPPP may or may not continue, but it is likely that more international utilities will be interested in entering South Africa's renewable energy market, especially European utilities that are struggling to grow shares in their home markets.

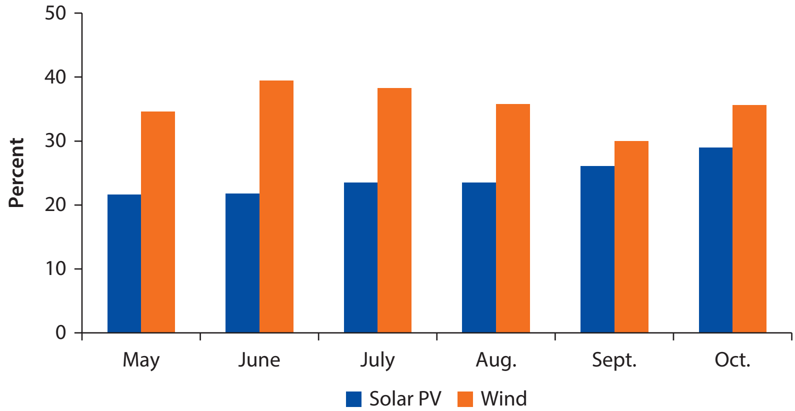
Table 8.8 Results of REIPPPP Rounds 1–3: South Africa, 2011–14

Bidding round	*Wind*	*PV*	*CSP*	*Hydro*	*Biomass*	*Biogas*	*Landfill*	*Total*
Round 1								
Capacity offered (MW)	1,850	1,450	200	75	12.5	12.5	25	3,625
Capacity awarded (MW)	648.5	626.8	150	0	0	0	0	1,425.3
Projects awarded	8	18	2	0	0	0	0	28
Average tariff (Rc/kWh)	114	276	269	n.a.	n.a.	n.a.	n.a.	n.a.
Average tariff (USc/kWh) R 8/$	14.3	34.5	33.6	n.a.	n.a.	n.a.	n.a.	n.a.
Total investment (R, millions)	13,312	23,115	11,365	0	0	0	0	47,792
Total investment (US$, millions) R 8/$	1,664	2,889	1,421	0	0	0	0	5,974
Round 2								
Capacity offered (MW)	650	450	50	75	12.5	12.5	25	1,275
Capacity awarded (MW)	558.9	417.12	50	14.4	0	0	0	1,040.42
Projects awarded	7	9	1	2	0	0	0	19
Average tariff (Rc/kWh)	90	165	251	103	n.a.	n.a.	n.a.	n.a.
Average tariff (USc/kWh) R 7.94/$	11.3	20.8	31.6	13	n.a.	n.a.	n.a.	n.a.
Total investment (R, millions)	10,897	12,048	4,483	631	0	0	0	28,059
Total investment (US$, millions) R 7.94/$	1,372	1,517	565	79	0	0	0	3,533
Round 3								
Capacity offered (MW)	654	401	200	121	60	12	25	1,473
Capacity awarded (MW)	787	435	200	0	16.5	0	18	1,456.5
Projects awarded	7	6	2	0	1	0	1	17
Average tariff (Rc/kWh)	74	99	164	n.a.	140	n.a.	94	n.a.
Average tariff (USc/kWh) R 9.86/$	7.5	10	16.6	n.a.	14.2	n.a.	9.5	n.a.
Total investment (R, millions)	16,969	8,145	17,949	0	1,061	0	288	44,412
Total investment (US$, millions) R 9.86/$	1,721	826	1,820	0	108	0	29	4,504
Totals								
Capacity awarded (MW)	1,984	1,484	400	14	16	0	18	3,915
Projects awarded	32	23	5	2	1	0	1	64
Total investment (R, millions)	40,590	42,130	33,797	631	1,061	0	288	118,497
Total investment (US$, millions)	4,683	5,085	3,806	79	108	0	29	13,790

Source: Eberhard, Kolker, and Leigland 2014.
Note: CSP = concentrated solar power; kWh = kilowatt-hour; MW = megawatt; PV = photovoltaic; REIPPPP = Renewable Energy Independent Power Project Procurement Programme; R = rand; Rc = rand cent; USc = U.S. cent; n.a. = not applicable.

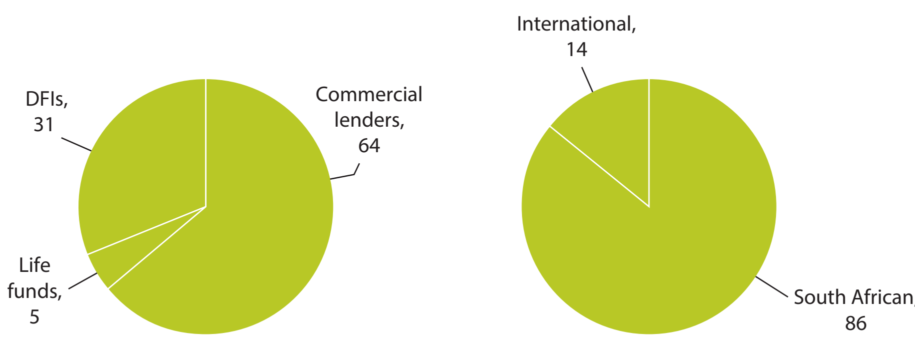
On average, across the three rounds, approximately two-thirds of funding was in the form of debt, with the highest proportion in round 2 and the lowest in round 3. A further quarter was funded from pure equity and shareholder loans, with the remaining coming from corporate finance. The majority, 64 percent, of debt funding was from commercial banks (R 57 billion), with the balance from development finance institutions (DFIs) (R 27.8 billion) and pension and insurance funds (R 4.7 billion). Eighty-six percent of the debt was raised from within South Africa (figure 8.11).[4]

Figure 8.10 Capacity Factors for Wind and Solar PV: South Africa, 2014



Source: Eskom System Operator.
Note: PV = photovoltaic.

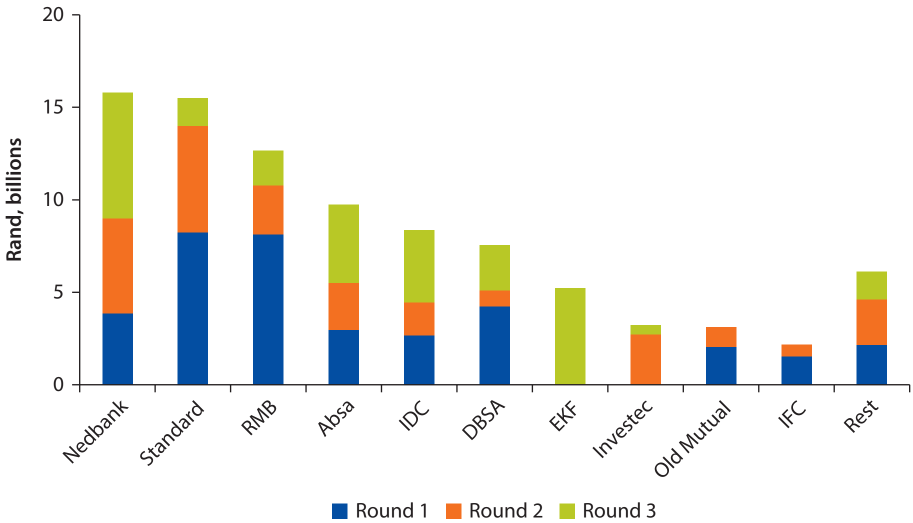
Figure 8.11 Share of Debt Financing in REIPPPP, Rounds 1–3: South Africa, 2011–14
percent



Source: Authors' calculations based on Department of Energy IPP Office data.
Note: DFI = development finance institution; REIPPPP = Renewable Energy Independent Power Project Procurement Programme.

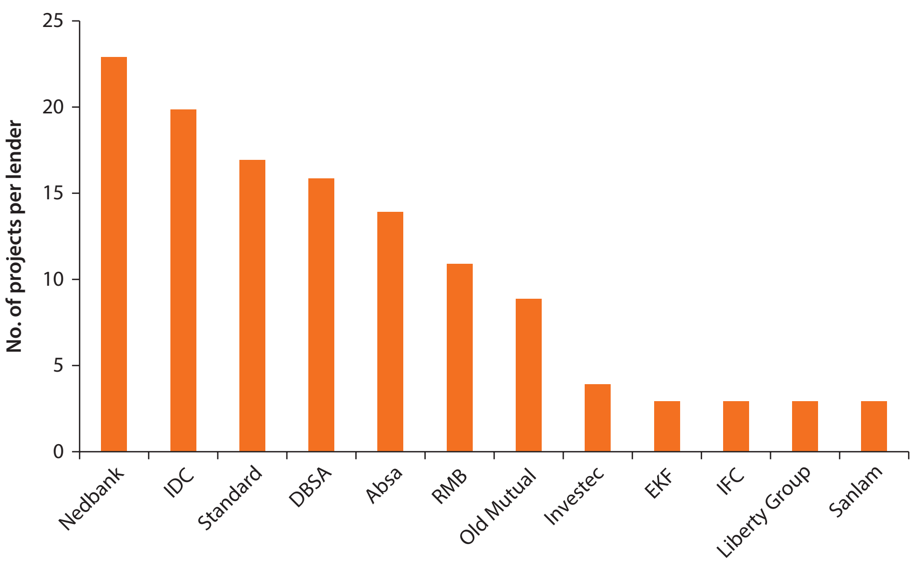
South Africa's five large commercial banks—Standard, Nedbank, Absa, Rand Merchant Bank (RMB), and Investec—have dominated REIPPPP lending. Their relative share of commercial and overall debt financing is shown in figures 8.12 and 8.13. Nedbank has been involved in the most projects (23), followed by Standard (17), Absa (14), RMB/First Rand (11), and Investec (4). These banks have all played lead debt-arranging roles, although not for all deals, and they have participated in a number of projects as cosenior lenders or as providers of subordinated mezzanine debt. Debt tenors are approximately 15 to17 years (from COD), and spreads on the Johannesburg Interbank Agreed Rate (JIBAR) are between 310 and 400 points (risk premium: 250; liquidity: 120; and statuary costs: 30 points). Nedbank and Absa were involved in the majority of projects in round 3. Some project sponsors have complained that there has not been enough

Figure 8.12 Share of Initial Debt Providers in REIPPPP, Rounds 1–3: South Africa, 2011–14



Source: Authors' calculations from the time of financial close, based on Department of Energy IPP Office data. Some debt has been subsequently syndicated to other banks or funds.
Note: The "rest" category includes OPIC, AfDB, Liberty Group, ACWA, EIB, Sanlam, FMO, Proparco, and Sumitomo. Absa = South African commercial bank; AfDB = African Development Bank; DBSA = Development Bank of Southern Africa; EIB = European Investment Bank; EKF = Eksport Kredit Fonden (Danish export credit agency); FMO = Netherlands Development Finance Company; IDC = Industrial Development Corporation; IFC = International Finance Corporation; OPIC = Overseas Private Investment Corporation; REIPPPP = Renewable Energy Independent Power Project Procurement Programme; RMB = Rand Merchant Bank.

Figure 8.13 Major Debt Providers in REIPPPP, Rounds 1–3, by Number of Projects per Lender: South Africa, 2011–14



Source: Authors' calculations based on Department of Energy IPP Office data.
Note: Absa = South African commercial bank; DBSA = Development Bank of Southern Africa; EKF = Eksport Kredit Fonden (Danish export credit agency); IDC = Industrial Development Corporation; IFC = International Finance Corporation; REIPPPP = Renewable Energy Independent Power Project Procurement Programme; RMB = Rand Merchant Bank.

competition among the banks, and premiums have not fallen as much as expected as banks became more familiar and comfortable with the REIPPPP process.

Remaining local debt funding came from the Industrial Development Corporation (IDC) and the Development Bank of Southern Africa (DBSA). The IDC participated in 20 deals, and the DBSA participated in 16 deals, mostly in arranging vendor financing for black economic empowerment and community participation.

Another feature of local financing has been the involvement of insurance and pension funds, such as Old Mutual, Sanlam, and Liberty. Old Mutual also participated through its Ideas Fund as well as its majority-owned specialist investment fund, Future Growth, and indirectly through African Clean Energy Developments, which is a joint venture between African Infrastructure Investment Managers (in turn a joint venture between Macquarie African and Old Mutual) and AFPOC (a Mauritian-registered company). It is expected that commercial banks will sell down more of their debt to these secondary capital markets and position themselves for ongoing debt exposure in future REIPPPP rounds.

International DFIs include the International Finance Corporation (IFC) and EKF (Eksport Kredit Fonden—the Danish export credit agency), with three projects each; and the Netherlands Development Finance Company (FMO), African Development Bank (AfDB), European Investment Bank (EIB), and Overseas Private Investment Corporation (OPIC), with one project each.

Public versus IPP Investment, Direct Negotiations versus Competitive Bids, and Thermal versus Renewables

Most of Eskom's power stations are coal fired, and there are not yet any coal IPPs. However, as mentioned earlier, two diesel-fired OCGT peaking plants are being built by an IPP and may be compared to Eskom's own direct procurement of a similar plant. In addition, the REIPPPP resulted in a number of wind farms, and Eskom is about to build its first.

Diesel-Fired Open-Cycle Gas Turbines

The Eskom-owned Ankerlig and Gourikwa diesel-fired OCGT plants were procured by the utility in two phases between 2007 and 2009. Siemens was identified as the main contractor to install 14 gas turbines (Ankerlig: 9 × 150 MW; Gourikwa: 5 × 150 MW) at the two sites. The contract awarded by Eskom was for only the engineering, procurement, and construction (EPC) of the plant at a total cost of R 7.7 billion for 2,072 MW of capacity—that is, a specific investment cost of R 3,716/kW (approximately $465/kW). This does not include the owner's costs, which could add an additional 30 percent—that is, approximately R 4,830/kW ($600/kW at the exchange rate of the time); see table 8.9.

The two OCGT plants (Avon and Dedisa) under the DoE's Peaker Project were initially procured through an ICB and then through direct negotiations for a turnkey solution that included the project management and operation services throughout the lifetime of the project. The successful bidder entered into an IA

Table 8.9 Procurement of OCGTs: A Comparison of Eskom's Plants and IPPs, South Africa

Project information	*Ankerlig and Gourikwa*	*DoE Peaker Project*
Sponsor	Eskom	GDF-Suez Consortium
Capacity	Ankerlig: 1,332 MW Gourikwa: 740 MW Total: 2,072 MW	Avon: 670 MW Dedisa: 335 MW Total: 1,005 MW
Cost	Phase 1: R 3.5 billion Phase 2: R 4.2 billion Total: R 7.7 billion (2009)	Total: R 9.7 billion (2013)
Specific investment cost	R 3,716/kW	R 9,652/kW
Time to COD	18 months	Dedisa: 24 months; Avon: 30 months
Commissioned	Phase 1: June 2007 Phase 2: May 2009	Avon: 2016 (expected) Dedisa: 2016 (expected)
Procurement	Tender for EPC only	International competitive bid and then direct negotiation

Source: Compiled by the authors, based on various primary and secondary source data.
Note: COD = commercial operation date; DoE = Department of Energy; EPC = engineering, procurement, and construction; IPP = independent power project; kW = kilowatt; MW = megawatt; OCGT = open-cycle gas turbine; R = rand.

with the DoE and a 15-year PPA with Eskom. The project-financed deal took seven years to conclude, and it was the first thermal IPP project in South Africa (Absa 2013). Specific investment costs amounted to R 9,652/kW ($965/kW at the ruling exchange rate)—50 percent more than the cost of Eskom's OCGTs. The PPAs of these diesel-fired OCGTs have not been made public.

Although, technically, the Peaker Project was a competitive bid program, competition in the market was limited. Only two prequalified developers submitted bids, but one was disqualified, leaving AES to win the bid by default. When negotiations with AES broke down, the deal was awarded to the only other (disqualified) bidder, raising doubt about the competitiveness of the deal. This was South Africa's first IPP, and the DoE had much to learn about running an effective procurement program.

Although all the data are not available, it can be safely concluded that Eskom's procurement of the OCGTs was both more cost-effective and quicker than the DOE's procurement of a similar plant.

Renewable Energy: Wind

Part of the World Bank loan made to Eskom in 2010 included funding for the 100 MW Sere Wind Farm, which thus had to be in line with the World Bank's procurement guidelines. An ICB was held for the EPC contract, which was awarded to Siemens, with a total value of R 1.8 billion (World Bank 2013). This included a five-year operations-and-maintenance agreement.

Projects under the REIPPPP are procured through a competitive bid for a 20-year PPA with Eskom as the off-taker. Competition has been fierce, with prices falling rapidly during the first four rounds.

According to Eskom, the Sere Wind Farm is expected to produce electricity at a cost of Rc 77/kWh (Blaine 2014). It is not clear whether this figure includes development and owner costs. This tariff is favorable to the REIPPPP rounds 1

Table 8.10 Wind Farm Procurement, South Africa

Project information	*Sere Wind Farm*	*Dorper Wind Farm*	*Red Cap-Gibson Bay*
Sponsor	Eskom	Sumitomo (majority shareholder) Rainmaker (developer)	Enel (majority shareholder) Red Cap (developer)
Capacity	100 MW	100 MW	110 MW
Cost	Project value: R 2.4 billion	Project value: R 2.2 billion	Project value: R 2.25 billion
	Overnight cost: $2,516/kW	Overnight cost: $2,182/kW	
	Tariff: Rc 77/kWh	Round 1 average: Rc 114/kWh	Tariff: Rc 66/kWh
Commissioned	Late 2014	July 2014	Early 2017 (expected)
Procurement	International competitive bid for EPC	Round 1 REIPPPP preferred bidder	Round 3 REIPPPP preferred bidder
Financing	World Bank loan 32.4%	70% debt financed	Corporate finance
	AFD 36.7%	Nedbank, Absa, Sumitomo Mitsui Banking Corp	
	AfDB 26.8%		
Operation	Five-year operations-and-maintenance contract with Siemens	20-year PPA	20-year PPA

Source: Compiled by the authors, based on various primary and secondary source data.
Note: Absa = South African commercial bank; AFD = Agence Française de Développement; AfDB = African Development Bank; EPC = engineering, procurement, and construction; kW = kilowatt; kWh = kilowatt-hour; MW = megawatt; PPA = power purchase agreement; R = rand; Rc = rand cent; REIPPPP = Renewable Energy Independent Power Project Procurement Programme.

and 2, in which wind farm prices averaged Rc 114/kWh and Rc 90/kWh, respectively. However, round 3 delivered prices as low as Rc 66/kWh, and the cheapest wind project in round 4 was Rc 56/kWh (or USc 4.7/kWh). This is an interesting outcome, because the World Bank loan to Eskom has an interest rate that is cheaper than the debt raised by the IPPs. Table 8.10 indicates that Eskom's specific investment costs are higher than the REIPPPP's, and that the utility has not been able to realize the competitive gains made by the IPPs.

Eskom has also been slow in getting its wind project off the ground and reaching a COD; REIPPPP projects with exactly the same EPC contractors were built in much smaller time frames.

It is also interesting to note the differences in the socioeconomic benefits of the Eskom project compared with the privately funded projects. Projects under the REIPPPP are required to have socioeconomic development interventions equal to between 1.0 percent and 1.5 percent of total project revenue and entrust between 2.5 percent and 5.0 percent of the total shareholding of a project to local communities. In addition, points are awarded for skill development, enterprise development, and local content.

By contrast, Eskom's wind farm appears to have no further socioeconomic benefits beyond job creation and local content.

Conclusions

South Africa has been a latecomer to IPP procurements in Africa, but in the past 4 years the country has added more projects and investments than did all the other countries of Sub-Saharan Africa in the previous 20 years. Initially, the national utility, Eskom, was charged with the responsibility to procure IPPs, but, facing an obvious conflict of interest with its own generation ambitions, it failed to contract adequate amounts of privately produced power. Even the FiT regime failed to deliver any projects, with Eskom continually raising issues around draft PPAs, associated contracts, and regulatory agreements.

The DoE started assuming responsibility for IPPs, but it realized early on that it did not have the capacity to run large, sophisticated power procurement programs. Its first procurement effort—the OCGT peaking plants—was a stop-start affair, with complicated negotiations, little competition, lengthy delays, and, in the end, expensive power.

Fortuitously, the DoE welcomed the assistance of experienced PPP advisers in the National Treasury and, along with an army of local and international transaction advisers, designed and ran what is now widely recognized and applauded as a world-class procurement of grid-connected renewable energy IPPs.

The REIPPPP's success was facilitated by the largely ad hoc institutional status of the DoE's IPP unit, which allowed an approach that emphasized problem solving, rather than an enforcement of administrative arrangements, and did not undermine quality or transparency. The DoE's IPP management team and the team leader had extensive experience, expertise, and credibility with both public and private sector stakeholders. This team was also able to overcome some of the mistrust regarding private business that sometimes restricts the public-private dialogue in South Africa and to secure resources to implement a quality program. These resources were used to appoint experienced advisers who were able to transfer international best practices to the South African context. Despite these successes, the ad hoc status of the DoE's IPP unit poses some risks. For this procurement process to be sustainable, these capabilities will need to be implemented in a formal institution, preferably an independent one.

The REIPPPP offered a quick way to roll out new generating capacity, and the size and structure of the bidding process meant that there would be multiple bid winners, an important incentive for the private sector to participate. The REIPPPP also represented opportunities for developers to make reasonable profits because the tariff caps in round 1 were close to the previously published FiTs. As competition increased in subsequent bid rounds, tariffs dropped sharply. The rolling series of bidding with substantial capacity allocations also helped build confidence in the program. Furthermore, the requirement that bids be fully underwritten with debt, as well as equity, effectively eliminated the tendency of competitive tenders to incentivize underbidding to win contracts.[5] Although some of the program's economic development requirements have been controversial, they did generate critical political support for the REIPPPP.

There were also some design shortcomings, and the size and readiness of the local renewable energy market were initially overestimated. This resulted in limited competition in round 1, with bids close to the price caps that were specified in the tender. Some REIPPPP critics also argued that the program's significant up-front administrative requirements and high bid costs have contributed to higher prices than in other countries, such as Brazil, and serve as a bias against small- and medium-scale entrepreneurs. Although the latter critique may have some merit, it should be noted that bid costs were nevertheless tiny compared to overall project values.

In terms of important market factors impacting the program, the global slowdown in renewable energy markets in the Organisation for Economic Co-operation and Development (OECD) meant that the REIPPPP was able to attract considerable attention from the international private sector. The REIPPPP also benefited South Africa's sophisticated capital market, which offered long-term project finance. The array of sophisticated advisory services was also critical to the design and management of the REIPPPP.

South Africa's experience suggests several key lessons for successful renewable energy programs in other emerging markets. For example, it is evident that private sponsors and financiers are more than willing to invest in renewable energy if the procurement process is well designed and transparent, transactions have reasonable levels of profitability, and key risks are mitigated by the government. Renewable energy costs are falling, and technologies such as wind turbine electric generation are becoming competitive with fossil-fuel generation. Furthermore, renewable energy procurement programs have the potential to leverage local social and economic development. The REIPPPP also highlights the need for effective program champions with the credibility to convincingly interact with senior government officials, effectively explain the program to stakeholders, and communicate and negotiate with the private sector. Finally, whether a FiT or competitive tender is chosen, private sector project developers need a clear procurement framework within which to invest.

Other interesting lessons from South Africa relate to public versus private procurement. In the case of renewable energy, competitive tenders and private sector developers produced better price outcomes (from round 3) and shorter construction times than the national utility, which had had no prior experience with renewable energy. However, the opposite outcome was achieved with thermal OCGTs: Eskom and its EPC contractors constructed a plant in a shorter period of time and at lower investment costs than the DoE-procured IPP. The latter was DoE's first procurement and was far from ideal, with limited competition, and eventually it had to resort to direct negotiations. It is almost certain that better outcomes could have been achieved through more competition.

South Africa's experience also demonstrates that much greater competition is possible among renewable energy providers—93 bids were received in the third round—than thermal power plants. The smaller project sizes, diversified and distributed renewable energy resources, and a highly competitive international market of project developers, equipment suppliers, and finance sources facilitate competition.

It is on these lessons that further thermal IPP procurements in South Africa will be built. It remains to be seen how competitive the coal baseload IPP bids will be. It is already certain, however, that bids will be below both the imposed price cap of approximately USc 7/kWh and the final costs of Eskom's new Medupi and Kusile plants. Bids for cogeneration plants were launched in 2015 along with a request for information for gas power projects that will lead to an RfP in 2016.

But there will be new challenges. It can no longer be assumed that the national utility, Eskom, will remain creditworthy. And as South Africa's fiscal situation tightens, there will be less room to offer sovereign guarantees, which will increase contingent liabilities for the National Treasury to unacceptable levels.

Finally, South Africa's experience demonstrates that significant investments in new electricity generation capacity are possible in a power sector that has undergone limited reforms. Although an independent regulator has been established and IPPs are permitted, the vertically integrated and state-owned Eskom has retained a dominant market position. Initially it discouraged the entry of IPPs, but the DoE managed to establish a separate procurement office and, with transaction advisers, an effective capability to run international competitive tenders.

Nevertheless, current arrangements are far from perfect and could easily be undermined. The powers given to the Minister of Energy to produce electricity generation expansion plans, and to translate the plans into timely procurement decisions (through ministerial determinations), have not been well used and have also restricted the regulator, which may license new generation investments only in line with these directives. Gazetted plans are out of date, demand forecasts have proven to be too optimistic, and the projected costs of various supply options are incorrect. More flexible, dynamic, and indicative plans and more space for private innovation around new generation supply investments would probably better ensure sufficient electricity supply in the future. South Africa's damaging power cuts are symptomatic of the failure of the current system. Eskom has not been able to supply enough power, and sufficient IPP capacity has not been procured on time.

The current institutional arrangements for IPP procurement are ad hoc and vulnerable to politically capricious decisions. The current power crisis in South Africa suggests that further reform is required. Unbundling generation and leaving Eskom with system and market operation, transmission, and perhaps also distribution could focus scarce management skills, improve efficiencies, and create a level playing field between public and private investments in generation. Planning, procurement, and contracting functions could be embedded in a nonconflicted Eskom. These are the key concerns in any sector reform or restructuring. Ultimately, successful power sector reforms are not about ownership or wholesale or retail competition as much as they are about the effectiveness of planning, procuring, and contracting new investments.

Notes

1. Nigeria recently rebased its gross domestic product, which now measures larger than South Africa's.
2. The first unit was commissioned in 1957.
3. An exchange rate of R 8/$ was used in the buildup to the Renewable Energy Independent Power Project Procurement Programme and for round 1 when the first agreements were signed. For Rounds 2 and 3, the exchange rate at the time of signing agreements was used to calculate project prices and investment values.

4. The Development Bank of Southern Africa, located in Johannesburg, has been classified as local in this analysis.
5. This requirement was relaxed in bid round 4.

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CHAPTER 9

Case Study 4: Power Generation Results Now, Tanzania!

Introduction

Tanzania has a vast array of conventional and renewable energy resources, and yet the country struggles to generate sufficient power to fuel growth and development. It has only 1,583 megawatts (MW) in installed generation, and imported fuel is a critical piece of its electric power generation. Network failures undermine what little power is produced. As a result, approximately 46 percent of the nation's total power consumption is from off-grid self-generation (averaging $0.35/kilowatt-hours, kWh) (NKRA Energy 2013: 12, 166).[1]

What has prevented Tanzania from harnessing its domestic resources in an economically efficient way, and what may be done differently going forward? There appear to be three key elements that directly affect Tanzania's electricity supply industry and generation procurement. The first is a lack of coherent and up-to-date planning; the second is related to the planning and contracting nexus, including the allocation of public and private generation projects. The third element is a lack of sustained commitment to private sector investment and competitive bidding practices. The gas sector also suffers from many of the same issues, with direct implications for power production.

The first section of this case study provides a history of how the sector developed, followed by a description of the current structure and capacity. Prices and plant performance are also presented. In subsequent sections, the analysis focuses on how capacity has been procured and financed (in both public and independent power projects, IPPs), as well as future plans. Finally, the case study offers conclusions related to fundamental elements that have contributed to and detracted from power generation development in Tanzania.

Tanzania's Electricity Sector: An Overview

A History of Power Sector Reforms

Electricity in Tanzania dates back to 1908, when colonial authorities (in what was then known as Tanganyika) installed electric power to run railway workshops in Dar es Salaam.[2] In the early 1930s, the colonial government decided to withdraw from the supply of electricity services. Thus, the Dar es Salaam and District Electric Supply Company (DARESCO) and the Tanganyika Electric Supply Company were established. Both utilities grew, and when Tanzania gained independence in 1961, the second of the two companies was exporting power to Mombasa in Kenya. After independence, the government sought to acquire both electric utilities, and a prolonged nationalization process took place (1964–75). During that time, the two utilities merged to form the Tanzania Electric Supply Company (TANESCO), which performed adequately in the 1960s and 1970s. In the 1980s, electric supply and distribution began to deteriorate and has remained poor since.

Repeated attempts at reform started in the early 1990s. In 1992, a National Energy Policy was formulated that opened the sector to private participation, including a provision to encourage private electricity generation and distribution in areas where TANESCO had not established a public power supply system. The next year, bids were invited for the country's first IPPs. Following this push, in 1997, TANESCO was earmarked for privatization. Under pressure from both the World Bank and the International Monetary Fund (IMF), these efforts intensified from 1999, and included a 100 percent increase in nominal tariffs.

By 2001, with electricity costs relatively high, the quality and reliability of supply still poor, and the financial standing of the state utility persistently weak, attention focused on TANESCO's management. In the same year, the government of Tanzania reconstituted TANESCO's board and initiated a management contract that was set up to last two years, starting in 2002, but ended up spanning four years. The objective of the contract was to achieve TANESCO's commercial turnaround with a view to privatizing the utility. When the contract was extended in 2004, its scope was widened to include improvements in technical performance. Meanwhile, in 2003 the National Energy Policy was updated; revisions were built on the 1992 policy and further emphasis placed on introducing competition into the sector, ensuring open access to the grid, prioritizing regional cooperation and integration, and developing indigenous resources and renewables for power supply.

While TANESCO's balance sheet improved under the management contract, specifically because of better collection, the quality and reliability of supply and the rate of new electricity connections did not increase materially, mainly because of underinvestment (Ghanadan and Eberhard 2007: 23). Then, in 2005, an incoming administration reversed plans and de-listed TANESCO from privatization, in direct opposition to an underlying objective of the management contract. In 2006, the government announced that the management contract would not be extended, a decision that met with wide public approval.

Two years later, in 2008, an Electricity Act was passed, updating the 1957 Electricity Ordinance Amendment that had until then governed the sector. With respect to the structure of the electricity industry, Clause 4(1) of the act states:

> The Minister shall provide supervis[ion] and oversight in the electricity supply industry and shall in that respect … take all measures necessary to reorganise and restructure the electricity supply industry with a view to attracting private sector and other participation, in such parts of the industry, [in] phases or time frames as he deems proper.

After nearly two decades of reforms characterized by a fluctuating commitment to private sector participation, the Electricity Act of 2008 appeared to signal a renewal of the government's commitment to reform the sector, albeit in part at the insistence of the donor community (as had been the case for the duration of the reforms).

In 2011–12, however, actual practices on the ground departed from this policy commitment, with the nontransparent procurement and installation of multiple emergency power plants (EPPs) and a push for four state-owned power projects. While privately owned, the EPPs worked contrary to the goals of competition and reform, as detailed below.

The "Big Results Now" (BRN) initiative (which came into effect in 2013) is rooted in the 2008 Electricity Act, which reaffirms the goal of unbundling and privatizing the sector. According to BRN, the mandate of the present planning framework, under Tanzania's Development Vision (TDV) 2025, is to transform Tanzania's future electricity landscape.[3] By 2025, Tanzania is expected to have installed 10,000 MW, more than six times the present capacity, which would represent a radical departure from past supply shortages (MEM 2014: i).[4]

In 2014, PricewaterhouseCoopers provided strategic advice related to the unbundling of TANESCO, advice that harkened back to the era of the management contract. The sector has long suffered from TANESCO's poor financial position, which was severely aggravated by the EPPs. As made evident in the most recent publicly available financial statement (from 2013), TANESCO's financial situation is dire:

> Without qualifying my opinion, I draw attention to users of the financial statements to Note 3 which indicates that during the year the Company incurred a net loss of Shs. 467,704 million (2012: Shs 177,399 million) and at the reporting date, the Company had accumulated losses amounting to Shs 1,450,380 million (2012: Shs 982,678 million). These conditions together with other matters disclosed in Note 3 indicate the existence of uncertainty on the smooth operation of the company (United Republic of Tanzania Audit Office 2013: 27).[5]

Strategic interventions, some supported by the World Bank's Development Policy Operation Credits I and II (DPO I-II), have aimed to address and ameliorate TANESCO's financial situation, with another under preparation. However, private stakeholders are concerned as arrears continue to increase and TANESCO remains far from being financially viable.

Other challenges for the sector include the lack of transparency, as discussed in the context of two high-profile cases (Independent Power Tanzania Ltd. [IPTL] and Richmond/Dowans) later in this case study, and what private investors have repeatedly described as the favoring of publicly funded projects over private investment. All new long-term projects in recent years have been or are going to be built and owned by TANESCO (despite, it should be emphasized, TANESCO's precarious financial situation) rather than the private sector. This unwritten policy has been formalized (through letters from the energy regulator to the energy minister), and going forward all private projects will be undertaken as public-private partnerships (PPPs). Furthermore, despite regulatory statutes that encourage a competitive approach, noncompetitive arrangements are the preferred method of doing business with the private sector.

What factors explain the country's shifts toward and away from private investment and reform measures, and the disconnection between adopted policy and actual practices on the ground? Part of this disconnect may be attributed to the fact that the numerous state actors involved are not united in their policy positions and approaches, and various factions have at times worked against one another.

Finally, it is worth noting that while feed-in tariffs (FiTs) are under discussion, there are presently no specific incentives for large-scale renewable projects.

The Sector's Structure and Institutions

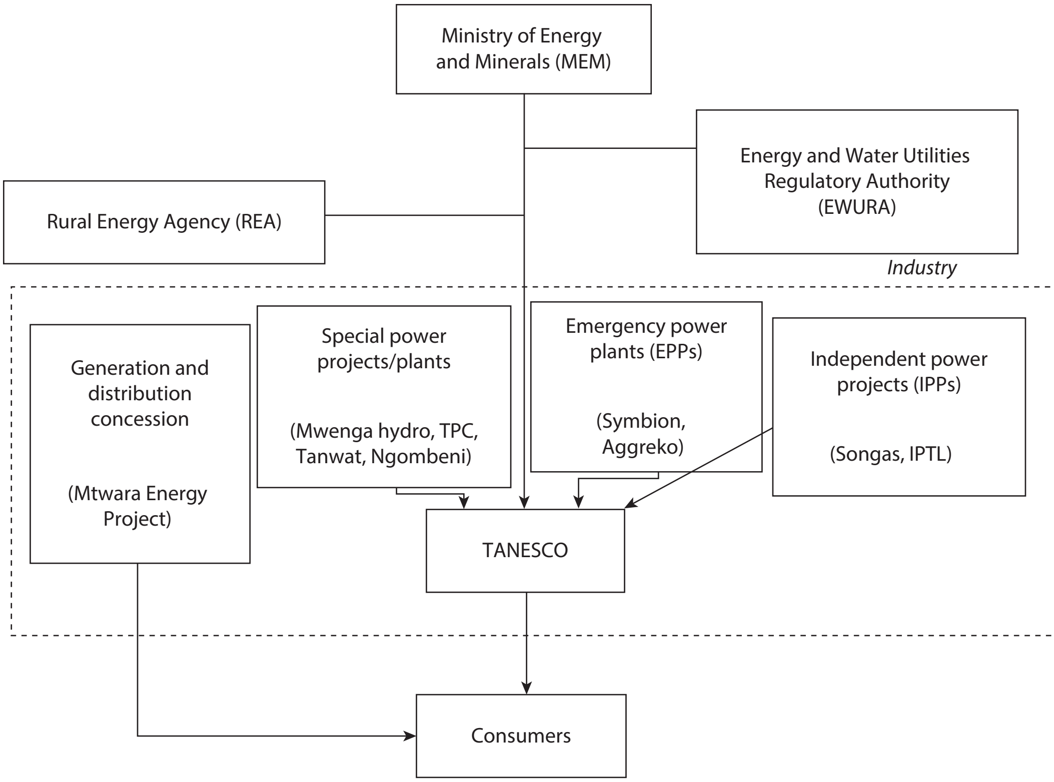
Notwithstanding the ambitious reforms envisioned for the electricity sector, its present structure continues to be characterized by a poor performing, vertically integrated, state-owned utility (whose attempts to contract IPPs are sporadic and not always successful), and the prominence of nontransparent deals (figure 9.1).

This is an important factor in evaluating the efficacy of planning, procurement, and financing, particularly of private power, and future investments in generation. The present structure also has implications for Tanzania's gas development, which is integral to electric power.

The government, through the Ministry of Energy and Minerals (MEM), is responsible for formulating energy policy. A statute dictates that the regulation of the sector be conducted by an independent regulatory agency, the Energy and Water Utilities Regulatory Authority (EWURA). As is increasingly the case across Africa, an autonomous body, the Rural Energy Agency (REA), has been charged with scaling up rural electrification. However, as will be discussed in more detail, EWURA has not always been emboldened to carry out the regulation that is its mandate.

At the industry level, all the defining features of a hybrid electricity market are visible. TANESCO dominates the sector, while IPPs (Songas[6] and IPTL) provide additional generation capacity, together with Mwenga hydropower, Tanganyika Planting Company (TPC), Tanwat, and Ngombeni through small power projects (SPPs).[7] The Mtwara Energy Project (MEP), formerly a remote rural gas-to-electricity generation and distribution concession, reverted back to

Figure 9.1 Overview of Tanzania's Electricity Sector, 2014



Note: IPTL = Independent Power Tanzania Ltd.; TANESCO = Tanzania Electric Supply Company; TPC = Tanganyika Planting Company.

TANESCO's control in 2012 after two years of operation, due to a mismatch between operating costs and revenue (TANESCO, personal communication, January 14, 2015).

Power Sector Processes

While the MEM is responsible for planning, TANESCO and EWURA have advisory and support roles. This has largely been an ad hoc arrangement to address performance issues within the MEM and across the planning process (TANESCO, personal communication, January 14, 2015). It presents a number of challenges, including the fact that TANESCO takes part in sector planning while simultaneously retaining an interest in building its own new power stations. The planning process is characterized by politics rather than impartial and sound (near- and long-term) decisions based on outside data sources. Although it is expected to continue for the foreseeable future, the Electricity Act of 2008 allocated the Power System Master Plan to an independent system operator (ISO). As of the first quarter of 2015, the ISO had not been established, though the most recent Reform Strategy and Roadmap stipulated that this should be done between July 2014 and June 2015 (MEM 2014: 42). Noteworthy in this context is that in the past 10 years, the MEM has seen five permanent secretaries, five ministers, and several different deputy ministers—a turnover that has had serious ramifications for the planning and associated execution and coordination processes.

Historically, the planning function was largely outsourced to TANESCO and consultants. A number of master plans and strategies have been produced over the years, but they have quickly obsolesced, and it would appear that they have not directly informed procurement decisions. The present Power Sector Master Plan (2012) was bolstered by BRN (2013), which has not introduced any new projects but has altered the priorities and the schedules of several others (MEM 2013: 11; NKRA Energy 2013: 458). While TANESCO has built some generation capacity, as described below, this has been funded by the government; the utility has no resources to finance its own future projects.

Meanwhile, numerous prospective IPP developers have entered into memoranda of understanding (MoUs) with the MEM in the past, but the ministry has limited capacity to assess value for money or undertake the negotiations necessary to bring these to fruition. As a result, very few projects have materialized, as will be highlighted in the forthcoming discussion of IPPs. Those that have been negotiated have been slow to come to commissioning. Furthermore, there has been limited application of international competitive tendering. Other planning mishaps are highlighted by the engagement of EPPs, as described as follows:

> The fact that the EPP was formulated in a highly charged atmosphere of political anger at the on-going power shortages was no reason to disregard normal planning precepts and government procurement requirements. The EPP should have been rooted in careful analysis of unsuppressed demand, should have acknowledged the dispersed capacity owned by the private sector, which is appropriately used in times of emergency, and the imminence of the commissioning of generation projects already being implemented (mid-2012).[8] The Ministry of Finance should have played a key role in formulating the EPP, requiring the Technical Working Group to carefully weigh up the costs of high levels of capacity increases against the risks of just "getting by" until mid 2012 with a minimalist strategy. (MEM 2011)

The Electricity Act gives EWURA the power to approve the initiation of procurement of power projects. These powers have been further defined under the Electricity (Initiation of Power Procurement) Rules, with the overarching goal of discouraging unsolicited proposals that fall outside the Power System Master Plan and are not financially viable for the state (Electricity Act [CAP 131]).[9] The rules came into effect as of January 1, 2015, and will affect projects presently under negotiation, but not existing IPPs (that is, Songas and IPTL). EWURA is supposed to review all projects in Tanzania, a principle that is enshrined in the Electricity Rules; however, it is not clear that the agency is sufficiently equipped to carry out this task. While the legislation came into effect in January 2015, negotiations over unsolicited proposals carry on. Among these, the Kilwa IPP, a 308 MW gas-fired project that has been highlighted among near-term projects, was introduced by retired public servants and one foreign investor.

Gas: Challenges and Potential

The discovery of significant offshore gas to the south is among the most positive developments in Tanzania in recent years (table 9.1). Contingent resources[10] are estimated at 29 trillion cubic feet (Tcf), although estimates of more than 50 Tcf have been reported.

In the near term, the first priority for Tanzania is to develop two liquefied natural gas (LNG) trains from deep-sea gas, entailing a commitment of 14 Tcf of gas. In the long term, at least two further LNG trains are planned. In parallel, Tanzania is aggressively pursuing a domestic gas-to-power agenda that could result in over 8 Tcf of gas being committed to the domestic market (Santley, Schlotterer, and Eberhard 2014). Supply from this offshore gas, however, depends on the LNG development proceeding. Offshore gas will not flow without an export market as it is too expensive and the volumes too low in the country to justify it.

As will be probed shortly, significant gas discoveries have the potential to change the landscape of Tanzania's electric power production, but this has not yet happened. The absence of relevant planning and timely implementation (including the development of pipeline and gas-processing infrastructure) along with a weak investment climate have prevented Tanzania from exploiting its gas potential. Instead, the country has continued to resort to EPPs. The high costs of engaging and fueling a fleet of EPPs with imports in the past five years (for 2012 alone, EPP costs were estimated to be $320 million) effectively bankrupted TANESCO.[11] It should be reiterated in this context that EPPs were all procured through nontransparent deals. Government support for TANESCO in this period was sporadic and insufficient to keep TANESCO liquid. As a result, TANESCO stopped paying the IPPs, EPPs, and some of their fuel suppliers. With funding obtained from donors and commercial lenders, including under DPO I, II, and (anticipated) III, TANESCO is beginning to recover from this financial shock, but until recently owed large arrears to the sector (estimated to be up to $300 million).

Table 9.1 Onshore and Offshore Gas Discoveries and Developments: Tanzania, 1974–2014

Field	*Discovery date*	*GIIP (Tcf)*	*Proven (Tcf)*
Songo Songo	1974	2.5	0.880
Mnazi Bay	1982	3–5	0.262
Mkuranga	2007	0.2	0.2
Kiliwani	2008	0.07	0.027
Mtwara-Ntorya	2012	0.178	—
Deep Sea	2010–14	35.10 (2013) 55.5 (March 31, 2015)	—
Total		**63 Tcf (assuming 5 Tcf Mnazi Bay)**	**Unknown**

Sources: Ng'wanakilala 2014; Energy and Water Utilities Regulatory Authority (figures received April 22, 2015).
Note: GIIP = gas initially in place, not proven reserves; Tcf = trillion cubic feet; — = not available.

Installed Generation Capacity

As of 2014, Tanzania's total installed generation capacity was 1,583 MW, including 561 MW of hydropower (35 percent), 527 MW of natural-gas-fired power plants (34 percent), and 495 MW of liquid-fuel power plants (31 percent), of which 53.6 MW is off-grid (table 9.2). Power is also imported from Uganda (10 MW), Zambia (5 MW), and Kenya (1 MW). The current profile is dramatically different from that of the recent past. Between 1980 and 2000, the majority of the supply was state-owned hydropower (which is still in operation, distributed across five plants of 8 MW, 11 MW, 68 MW, 80 MW, and 204 MW each).

A number of additional observations are noteworthy. First, nearly 57 percent of the grid capacity installed from 2000 (or 643 MW) was privately sponsored; of this, 331 MW was private emergency power. Thus, more than half of all private power was via short-term, nontransparent, emergency contracts. Furthermore, while the relatively new power installations diversified away from

Table 9.2 Grid-Connected Capacity: Tanzania, as of 2014

Name	*Ownership*	*Installed*	*Retire*	*Fuel*	*Installed capacity (MW)*
Hale	TANESCO	1967	2017	Hydro	21
Nyumba ya Mungu	TANESCO	1968	2018	Hydro	8
Kidatu	TANESCO	1975	2025	Hydro	204
Zuzu diesel	TANESCO	1980	2015	Diesel	7.4
Mtera	TANESCO	1988	2038	Hydro	80
Tanwat	SPP/IPP	1995	2029	Biomass	2
Pangani Falls	TANESCO	1995	2045	Hydro	68
Kihansi	TANESCO	2000	2050	Hydro	180
Tegeta IPTL	IPP unit	2002	2021	HFO	103
Songas 5	IPP unit	2004	2024	NG	38
Songas 1–4	IPP unit	2004	2024	NG	114
Songas 6	IPP unit	2006	2024	NG	37
Tegeta GT	TANESCO	2009	2028	NG	45
TPC	SPP/IPP	2010	2030	Biomass	17
Ubungo I	TANESCO	2008	2026	NG	102
Aggreko Tegeta	Aggreko, rental	2011	2014	Gas oil	50
Aggreko Ubungo	Aggreko, rental	2011	2015	Gas oil	50
Symbion Ubungo	Symbion, rental	2011	2015 converted	NG/Jet	126
Mwenga	SPP/IPP	2012	2030	Hydro	4
Symbion Arusha	Symbion, rental	2012	2014	Diesel	50
Symbion Dodoma	Symbion, rental	2012	2014	Diesel	55
Ubungo II	TANESCO	2012	2031	NG	105
Nyakato/Mwanza	TANESCO	2013	2038	HFO	63
Total					**1,529**

Sources: MEM 2013: 16; data received from TANESCO (November 14, 2014; January 9, 2015).
Note: Off-grid and grid-connected together total 1,583 MW. Grid alone accounts for 1,529 MW. HFO = heavy fuel oil; IPP = independent power project; IPTL = Independent Power Tanzania Ltd.; MW = megawatt; NG = natural gas; SPP = small power project; TANESCO = Tanzania Electric Supply Company; TPC = Tanganyika Planting Company.

hydropower, imported gas oil and heavy fuel oil (HFO) have remained prominent in the mix, and only TANESCO's new builds, along with Songas, have utilized domestically produced natural gas. Thus, leaving aside any contracting issues, the new power has been associated with costly imported fuel (electricity prices will be discussed further below).

This power landscape is, however, changing. The "Electricity Supply Industry Reform Strategy and Roadmap 2014–15" set the aggressive goal of retiring 205 MW of 331 MW by December 2014 as a means to improving TANESCO's financial performance. Of this, 155 MW was phased out over the course of 2014. Two units (Symbion Arusha and Symbion Dodoma), amounting to 105 MW in emergency power, were retired in June 2014, and Aggreko Tegeta (50 MW) was subsequently retired end-November 2014, as per contract specifications. The 50 MW of Aggreko Ubungo, slated to be retired by February 2015, was retained amid expectations in 2Q2016 of a dry year in 2016 and a further delay in gas supplies. The last of the EPPs, Symbion Ubungo (126 MW)—which was to be recommissioned, converted to an IPP contract in April 2015, and run on Tanzanian natural gas—has also been delayed, as of 2Q2015 (TANESCO is still negotiating the power purchase agreement [PPA], and gas supplies are delayed as well). As a result, only 50 percent of EPP capacity has been phased out, in contrast to the 100 percent envisaged.

Power Sector Performance

The performance of the sector is also critical to evaluating both private and public sector generation. This analysis has implications for the future of BRN and the proposed 10,000 MW and sector unbundling. It should be reiterated at the outset that while TANESCO is breaking away from its spiral of debt, its financial situation has been dire (with arrears running into the millions of dollars), which has been a significant barrier to attracting new investors through transparent channels.

Electricity Produced

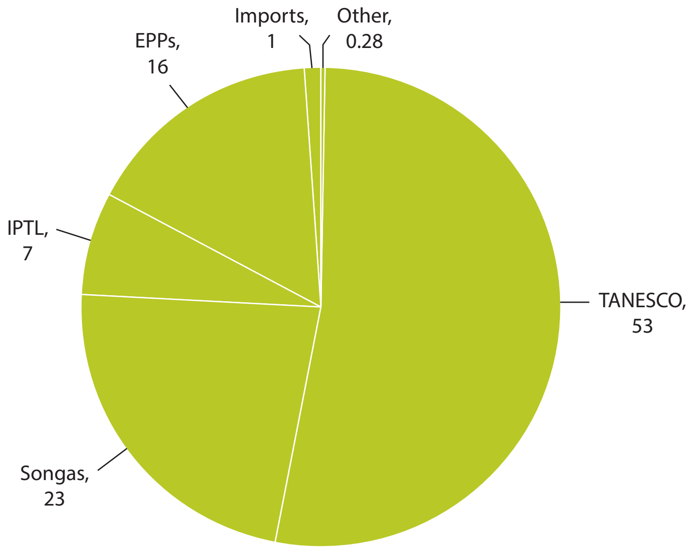
The actual units generated in 2013 reflect a reliance on older, state-owned plants (installed before 2000) that are still in operation. In 2013, 53 percent of the power was generated by TANESCO (with a further split of 30 percent state-owned hydropower and 24 percent thermal); 46 percent was produced by IPPs (Songas and IPTL) and EPPs, with a balance of 1 percent contributed by imports (figure 9.2). EPPs and IPTL together accounted for nearly 50 percent of all privately generated power; this generation relied on HFO, gas oil, and/or jet fuel.

Electricity Prices

Table 9.3 lists the costs of bulk supply borne by TANESCO. The average cost per kilowatt-hour is $0.15, which is closely reflected by the present electricity end-user tariff in Tanzania ($0.15–$0.16/kWh on average).

If EPPs are removed from table 9.3, the average cost of supply falls to approximately $0.10/kWh, evidence of EPPs' impact on price. However, such snapshots

Figure 9.2 Share of Grid-Generated Electricity Production, by Type of Producer: Tanzania, 2013
percent



Source: Compiled by the authors, based on TANESCO data.
Note: Other (0.28 percent) includes the small private producers Tanwat, TPC, and Mufindi. EPP = emergency power plant; IPTL = Independent Power Tanzania Ltd.; TANESCO = Tanzania Electric Supply Company; TPC = Tanganyika Planting Company.

Table 9.3 Shares/Costs of Capacity and Generation, by Type of Producer: Tanzania, 2013

Producer	*% of installed capacity*	*% of generation*	*Total kWh*	*Total cost/bulk supply tariff (US$)*	*$/kWh*
TANESCO	54.58[a]	53.36[a]	3,109,117,152	313,025,914	0.10
Songas	11.69	22.68	1,321,600,000	65,881,760	0.05
IPTL	6.32	7.03	409,463,300	126,933,623	0.31
EPPs	20.09	15.64	911,561,640	364,624,656	0.40
Total/average	**92.68**	**98.72**	**5,751,742,092**	**870,452,737**	**0.15**

Source: Authors' compilation based on 2013 data provided by TANESCO (November 12, 2014) and Songas (February 20, 2015), verified with the Energy and Water Utilities Regulatory Authority (April 20, 2015).
Note: TANESCO's average derived cost excludes the cost of capital. EPP = emergency power plant; IPTL = Independent Power Tanzania Ltd.; kWh = kilowatt-hour; SPP = small power project; TANESCO = Tanzania Electric Supply Company; TPC = Tanganyika Planting Company.
a. Off-grid, imports, and SPPs (Tanwat, TPC, and Mwenga) all excluded from these tallies, hence generation does not total 100 percent. The associated off-grid cost is $0.328, albeit representing only 5 percent of the total generation.

do not reflect the full reality of the costs involved. In the case of TANESCO, for which a per plant cost is not available, the per unit cost[12] listed in table 9.3 is solely a function of TANESCO's running costs and does not include depreciation or finance costs. Unlike for IPPs (Songas and IPTL), electricity users are not paying for any portion of the capital costs of the TANESCO-owned plant, which are government subsidized. These costs are, however, still incurred and are generally paid by taxpayers. It remains a challenge to determine TANESCO's actual costs,

Table 9.4 Comparison of Costs, by Type of Producer: Tanzania, 2013
US$/kilowatt-hour

Producer	*Running/fuel cost*	*Capacity cost*	*Total cost*
TANESCO	0.10	n.a.	n.a.
Songas	0.013	0.037	0.05
IPTL	0.22	0.08	0.31
EPPs	0.29	0.11	0.40
Total/average			**0.15**

Source: Authors' compilation based on correspondence with TANESCO stakeholders (2014).
Note: EPP = emergency power plant; IPTL = Independent Power Tanzania Ltd.; TANESCO = Tanzania Electric Supply Company; n.a. = not applicable.

including all capital-related expenditure and financing, and comparing these systematically with those of private plants using similar technology at comparable load factors.[13]

Songas, whose contribution to generation is second to that of TANESCO, has a different price structure. Its per kilowatt-hour all-inclusive charge comes to approximately \$0.05. The average variable charge, a function of competitively priced domestic gas, amounts to a fraction of this total cost, namely U.S. cents (USc) 1.2–1.3/kWh; this is significantly better than TANESCO's running cost (table 9.4).

IPTL trails the EPPs in terms of kilowatt-hours contributed, but it resembles Songas in its cost structure as a traditional IPP, and therefore is highlighted here. Capacity charges averaged \$0.08/kWh in 2013, almost double Songas's total cost. Taking into consideration differences in technology, this figure appears to be possibly inflated (causes associated with load factors but also with nontransparent procurement will be further observed in the next section). Of the remaining \$0.23/kWh in charges for IPTL, \$0.22/kWh is accounted for by the imported fuel variable charge, which is a complete pass-through item. Thus the overwhelming cost of this IPP is for fuel. While the total unit charge for IPTL is six times greater than that of Songas, it is on par with the running costs of TANESCO's Mwanza 60 MW HFO plant, which was financed by the government and came online in 2013. The current unit running cost of the Mwanza plant is \$0.23/kWh, excluding the repayment of loans and interest, which has yet to be finalized between TANESCO and the government of Tanzania.

EPPs, namely Symbion and Aggreko, contributed only 16 percent of the generation pie in 2013; however, their costs exceeded that of TANESCO's own generation, albeit based purely on TANESCO's running cost for supplying more than 50 percent of total generation. Although the weighted average for the EPPs is \$0.40, this masks significant differences in per unit costs (see table 9.5).

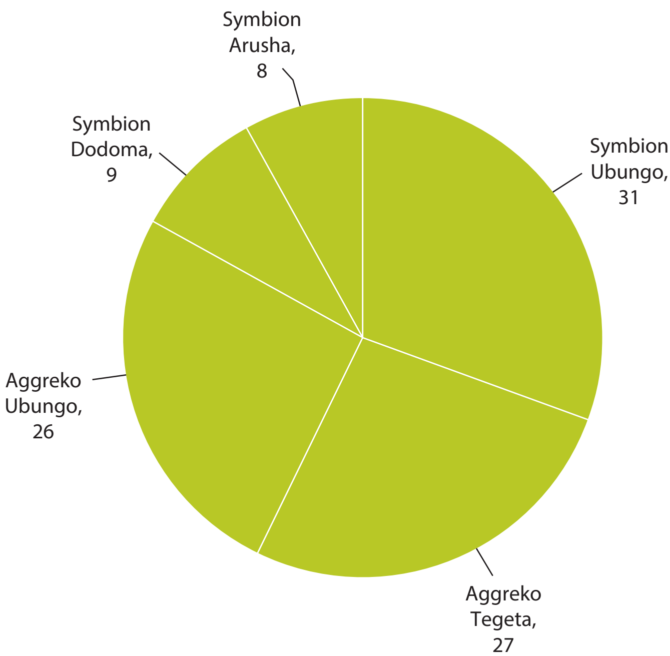
As with IPTL, the capacity charge of the EPPs is overshadowed by the variable charge, which is a pass-through and makes up the majority of the total cost (72 percent). In certain projects, such as Aggreko Ubungo and Aggreko Tegeta, the fuel amounts to 87 percent of the cost. There are, however, important differences across EPPs. For instance, Symbion Ubungo runs partly on (domestic) gas,

Table 9.5 Costs of Generation, by Emergency Power Plant: Tanzania, 2013
US$/kilowatt-hour

EPP	*Cost*
Symbion Ubungo	0.19
Aggreko Ubungo	0.39
Aggreko Tegeta	0.40
Symbion Dodoma	0.78
Symbion Arusha	0.80
Weighted average	**0.40**

Source: Authors' compilation based on TANESCO data (November 2014).
Note: EPP = emergency power plant; TANESCO = Tanzania Electric Supply Company.

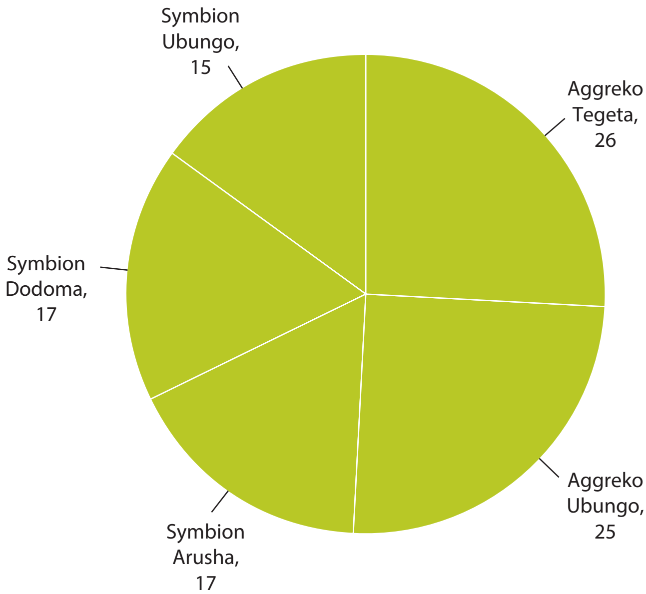
Figure 9.3 Emergency Power Plants' Contributions to Generation (GWh): Tanzania, 2013
percent



Source: Authors' compilation, based on TANESCO data (November 2014).
Note: GWh = gigawatt-hour; TANESCO = Tanzania Electric Supply Company.

accounting for its low unit cost compared with other EPPs; yet, because of insufficient gas, Symbion Ubungo's capacity factor remains low. Finally, there is a cause-and-effect dilemma involving electricity prices and capacity factors; that is, high electricity prices (as in the case of Symbion Dodoma) contribute to low capacity factors, which in turn contribute to higher per unit costs. Figures 9.3 and 9.4 depict the various EPPs' contributions to generation and total costs, respectively.

Figure 9.4 Emergency Power Plants' Shares of Total Costs: Tanzania, 2013
percent



Source: Authors' compilation, based on TANESCO data (November 2014).
Note: TANESCO = Tanzania Electric Supply Company.

In sum, despite incomplete data on costs, it is clear that the system is out of balance: EPPs and IPTL account for an inordinate portion of costs, relative to their actual production. This is due in large part to imported fuel charges. It is anticipated that if the debt incurred by the EPPs were to be paid off, TANESCO would break even (EWURA, personal communication, February 28, 2015).

Songas measures up to TANESCO's plants in relation to capacity factors and excels in terms of lower prices, which signals some positive developments in terms of private power (but here, too, there have been issues, as discussed in the next section).

IPTL and Songas, and the Next Generation of Independent Power Projects

As noted at the outset, the three key elements that have come to define Tanzania's generation procurement are a lack of coherent and up-to-date planning; a planning and contracting nexus, including the allocation of public and private generation projects; and a lack of sustained commitment to private sector investment and transparent bidding practices. Each of these areas is highlighted in the IPP experiences discussed below.

This section looks first at the evolving role that natural gas has played in the power sector, then at IPP developments dating from the mid-1990s and how they affected the outcomes of individual projects and the sector as a whole. What lessons have been learned, and what changes have been made—specifically in terms of planning, procurement, and contracting—to ensure that history does not repeat itself?

An Early Gas Discovery at Songo Songo and a Gas-to-Electricity Plan

In 1974, approximately 2.5 Tcf of gas was discovered at Songo Songo (offshore and on the island itself, about 200 kilometers [km] south of Dar es Salaam).[14] The initial plan was to harness gas for fertilizer production. The government of Tanzania partnered with Agrico, a U.S. company, in 1981 to form the Kilwa Ammonia and Urea Company (KILAMCO, with 51 percent of shares held by the government and 49 percent by Agrico).[15]

By 1989, with little to no progress made, negotiations collapsed. Failure to close the deal is attributed in part to the poor investment climate at the time, which did not adequately support foreign direct investment (FDI). Meanwhile, the idea to use gas for power had long been considered by the MEM, but public funds were insufficient and private investment not forthcoming. The MEM began a more focused evaluation of the gas-to-power option after the Agrico deal fell through. By 1991, it had been determined that gas-based power generation was the next least-cost option to hydropower and quicker to develop than other sources. This idea became a cornerstone of the Power System Master Plan in the same year.

Around that time, the government was approached by Ocelot (which today operates under the name PanAfrican Energy Tanzania Limited, PAT),[16] a Canadian-based gas company, with a proposal to develop Songo Songo. Among the options discussed were LNG development, a gas pipeline for export to Mombasa, and gas for domestic use. Two different plans were endorsed by consultants, but no conclusion was reached at this early stage.[17]

On the heels of Ocelot's initial proposals, starting in 1992, the country experienced a major drought. The MEM sought emergency measures to plug its power shortage. In November 1992, the Swedish International Development Cooperation Agency (Sida), Tanzania's largest bilateral energy donor, provided funds for TANESCO to procure approximately 40 MW of power (two 18 MW ABB GT 10A open-cycle turbines, which ran on jet fuel).[18] The turbines were installed at Ubungo. Sida also committed to meeting the operating costs (primarily fuel costs) of the turbines in the first two years, which amounted to about $35 million. It was expected that by the end of 1993, or shortly thereafter, gas from Songo Songo would be available; that is, before the grant for fuel was exhausted, the country could convert to domestic gas to feed the two turbines (despite the fact that the gas infrastructure had still not been contracted).

Amid persistent power shortages and mounting pressure to procure fuel for the Ubungo plant, in February and March 1993 the MEM invited 16 companies with experience in gas and power development to bid for the Songo Songo gas-to-electricity project. According to stakeholders at the MEM, competition for the project was a prerequisite of the World Bank, which at the time was active in reform proposals in Tanzania's electricity sector.[19]

The invitation contained a basic project concept to rehabilitate existing gas wells (which had been drilled in the 1970s), develop a pipeline to Ubungo, convert and supply two existing turbines, and add an additional 60 MW (in the form of two additional units) under a build-own-operate-transfer (BOOT) arrangement.[20] Firms were allowed to form consortia to ensure both upstream and downstream expertise. Among those companies invited were Enron, British Gas, Amoco, and Ocelot.

At the time of the initial invitation, no credit enhancement was provided (that is, no sovereign guarantees and no escrow accounts), despite a widely perceived poor investment climate and an insolvent utility. Furthermore, firms were given only six months to submit bids; a deadline of August 1993 was set by the MEM. Also, the plant size (of 60 MW) was small by international standards.

Because of these limitations only 2 out of the 16 invitees submitted bids: OTC, a joint venture between Ocelot Energy Inc. and TransCanada Pipelines (a Canadian firm with expertise in power development), and a joint venture of Enron and Andrade Gutierrez.[21] In December 1993, the MEM, TANESCO, and the Tanzania Petroleum Development Corporation (TPDC) met to review proposals, ultimately recommending the OTC bid to the minister of energy. The World Bank was consulted in January and February 1994, and OTC was officially awarded the tender by February 1994. By July 1994, negotiations commenced in Dar es Salaam; the project company Songas (which was composed of Ocelot) held a 25 percent equity stake and TransCanada the balance of the equity.

As negotiations were gaining momentum, the country experienced yet another drought, in November 1994. At this time, additional equity partners were under consideration, including the TPDC and TANESCO, which would eventually formalize their stakes in the project by October 1995, together with those listed earlier. In addition, over 20 different contracts were being drafted to satisfy the requirements of the Songo Songo project participants, and financial close had not yet been reached. Rather than wait the six months or more before the project was finalized, the MEM sought to install additional emergency capacity at Ubungo.

Persistent Power Shortages and the Emergence of IPTL

It was at this time that the government began considering, among others, the IPTL project proposal to yield an additional 100 MW. The IPTL project company was formed between the Malaysian firm Mechmar (70 percent) and the Tanzanian firm VIP Engineering Limited (30 percent).

According to numerous stakeholders, the IPTL deal grew out of south-south collaboration, which was being heralded at the time as an alternative to the north-south donor-recipient model of the previous decades. Unlike for Songas, there was no formal tender. However, amid persistent power shortages the government sought a fast-track way to increase its non-hydropower generation capacity. A meeting was convened on December 15, 1994, to address this objective; it was agreed that IPTL could not meet the fast-track power deadline for mid-1995, but that the firm's proposal might be considered within the context of the country's long-term power plan.

Instead, through a World Bank facility, the government was able to finance two additional turbines of 35 MW each. Combined with the previous turbines, this now made up a total of approximately 106 MW at Ubungo, which met the immediate shortage, and IPTL was deferred. As with the previous turbines, it was expected that they would be converted to burn natural gas at the earliest possible date.

IPTL Dispute and Its Implications for Songas

Meanwhile, Songo Songo negotiations continued. The Tanzania Development Finance Company Limited (TDFL, sponsored by the European Investment Bank, EIB), International Finance Corporation (IFC), German Investment and Development Corporation (DEG), and the power company Commonwealth Development Corporation (CDC) all joined the project company by February 1996. Further provisions agreed to later in 1996 included an allowance for funds used during construction (AFUDC) and an escrow account.

Although Songas was expected to materialize in the near term, during the same period, negotiations reached completion with IPTL. A PPA was signed between the government and IPTL for a 100 MW diesel generator in May 1995, which was expected to be converted to run on natural gas with the completion of the Songo Songo gas-to-electricity project. Standard security arrangements and credit enhancements were sought and obtained; their terms differed from those negotiated by Songas, however, mainly because the MEM never formalized a set of standard IPP terms and conditions, and the projects were negotiated by different stakeholders.

The circumstances surrounding the IPTL agreement have been widely debated; several stakeholders allege corruption and point to the fact that since the project was not included in the Power System Master Plan, it would make Songas redundant. Other stakeholders argue that the project emerged from a genuine south-south collaboration with Malaysia, was identified as a viable solution by the government as early as December 1994, and that the parties agreed (legally) to the terms of the PPA.[22]

The impact of the IPTL agreement was not immediate. Negotiations with Songas were ongoing and the project company continued to make equity disbursements to fund the development of the project (with an impact on the AFUDC) until 1997. In this year, several things happened. First, IPTL reached financial close, with funding committed by two Malaysian banks, and started construction.[23] Second, in the latter part of 1997, Tanzania's hydrological situation reversed due to the weather phenomenon of El Niño. Starting in December, reservoirs began filling and would ultimately overflow (sustaining the country until 2001). Finally, IPTL plant costs amounted to \$150 million (with an additional \$13 million budgeted for fuel conversion to natural gas, for a total of \$163 million). As a result, Tanzania found itself overcommitted in terms of capacity; the country needed at the most one plant but certainly not two.

With power now in abundance and financial liabilities mounting, TANESCO served a notice of default to IPTL in April 1998, with an intention to terminate the contract. The charge made by the utility was that IPTL substituted medium-speed engines for slow-speed ones, but did not pass on the capital cost savings to the utility. Contrary to earlier cost estimates, the government determined that a plant of similar size, using similar technology, would cost no more than $90 million. Disagreement over the substitution[24] and the capacity payment persisted throughout 1998, culminating in a Request for Arbitration on behalf of TANESCO at the International Centre for Settlement of Investment Disputes (ICSID). Meanwhile, IPTL filed a petition with the High Court of Tanzania claiming that commercial operations were to commence in August 1998, and as a result, IPTL was owed capacity charges of $3.6 million for each month from that date. This petition would eventually become part of the ICSID tribunal once it was convened in June 1999.

While the tribunal involved several phases, the final award, made in May 2001, upheld the PPA signed in 1995, adjusted the capacity charge to $2.6 million per month, and indicated that conversion to natural gas would be as per the original PPA—with the costs of conversion paid by TANESCO (with a benchmark of $11.6 million set) and work to be carried out by Wartsila.[25]

During the three-year dispute between IPTL and TANESCO, Songas would be put on hold amid concerns that the utility could not absorb power from two plants. Three critical developments occurred during this period. First, although no additional work was completed by the sponsors, the AFUDC continued to compound at a rate of 22 percent per year. Second, the scope of Songas was scaled down from 151 MW (as per the 1995 negotiations) to 106 MW in light of the expected IPTL capacity. Third, significant changes occurred in the composition of the project sponsors.

Both the IFC and DEG pulled out of Songas shortly after the IPTL dispute became known (with the CDC taking over their associated financial obligations of approximately $12 million). Furthermore, by 1999, TransCanada arranged for the sale of its majority share to a U.S.-based power development firm, citing a strategic decision to consolidate its assets in North America. Two years later, Ocelot would do the same, though for a different reason, namely, consolidating its interests in the Songo Songo gas field exclusively (see details on the production-sharing agreement between the TPDC and PAT in annex 9D). Thus, by the time the IPTL arbitration had been concluded and sufficient demand had been ascertained, the AFUDC had increased substantially and the original lead sponsors of Songas had all but transformed (with only the CDC, TPDC, and TDFL maintaining their minority shares in the project).

It was under AES that the PPA was completed; financing for Songas was eventually finalized in October 2001, nearly a decade after Ocelot had first approached the government.[26] By 2003, however, with work well under way on the refurbishment of the Songas turbines, AES would sell the majority of its shares to Globeleq.[27] During this sale, the government negotiated with the new lead shareholder to buy down the AFUDC to keep future tariffs sustainable.

Initially, the AFUDC was to be wrapped into the capacity charge; however, because of the extensive project delays, by April 2003 the amount had ballooned to $103 million and would have meant a monthly capacity charge of more than $6 million, equivalent to almost 30 percent of TANESCO's revenues. The buy down of the AFUDC was agreed to by Songas's new owners and financed by the Ministry of Finance (50 percent), TANESCO (10 percent), and the Songas Escrow facility[28] (40 percent), which by 2003 totalled about $50 million. Globeleq did not require an escrow facility as a condition of its purchase, and the facility has not been replenished.

Controversy Continues

In the years since these events, power has been supplied by both Songas and IPTL, with IPTL power being considerably more expensive. Despite the original plan dating to 1995 and reinforced in the 2001 arbitration, IPTL has still not been converted to run on natural gas.[29] One of the impediments to the conversion is that while the ICSID tribunal was concluded, legal issues related to project sponsors stymied further developments.

Another plan was for the government to buy back IPTL's debt; however, this has not materialized. Furthermore, controversy surrounded the sale of IPTL to Pan Africa Power Solutions (PAP) and the subsequent transfer of funds from the Bank of Tanzania (escrow account) to PAP. According to TANESCO, there is no near-term plan to convert IPTL to natural gas.

The lessons from Tanzania's experience with IPTL could not be more explicit. When power is not planned, procured, and contracted transparently and consistently, the implications are potentially grave, far-reaching, and ongoing. Rather than being considered a planning and procurement mishap, however, IPTL is often used to emphasize the drawbacks of private sector participation. Meanwhile, Songas has not been widely recognized as a successful competitive bid or as an example of how the private sector can work strategically to harness more power. Instead, it has been charged with having advanced private interests at the expense of the state, including obtaining key assets such as pipeline infrastructure that are in the strategic interests of the country.

Symbion, Following Independent Power Tanzania Ltd.

At its inception, the Symbion case seemed to replicate some of the planning, procurement, and contracting issues experienced around IPTL. Originally specified for a two-year contract to plug an immediate power shortage in 2006, Symbion Ubungo (a 126 MW project previously known as Richmond/Dowans) is now slated for a long-term IPP contract; its project duration has already exceeded eight years. Apart from its longevity, it is worth noting the controversy surrounding the project.

Agreement was struck, in a nontransparent manner, with Richmond, a special-purpose vehicle (SPV) formed in 2006 to provide 100 MW of emergency power.

The contract was stipulated for two years starting in September 2006 (20 MW) followed by the balance (80 MW) by February 2007, which was safeguarded by a government guarantee. The first 20 MW (of the 100 MW) was, however, brought online in October 2006, and fueled with natural gas supplied by Songo Songo. This occurred only after the government advanced Richmond funds, as neither the parent company (which it turns out is a publisher with no prior experience in power supply) nor the subsidiary (operating from a residential address in Houston) had money to lift the generators. Dowans Holdings, based in the United Arab Emirates (UAE), subsequently bought the plant and took over the contract, and saw the addition of 60 MW capacity, albeit only by August 2007—six months later than expected. When the plant finally came online it was not fully functioning and by the time all issues had been resolved Tanzania was no longer in need of the power, yet it was legally contracted to purchase it or pay penalties. The Richmond/Dowans fallout led to the resignation of then–prime minister Edward Lowassa and two other ministers on charges of alleged associated corruption in 2008.

In contrast to the nontransparent arrangements of 2006, the present negotiations with Symbion are overseen by EWURA and governed by the Electricity Act (CAP 131) of 2014, and thus different outcomes may be anticipated. The expectation is that the cost structure will change, both with respect to the capacity charge and the fuel. The reference point TANESCO provided for the Symbion negotiation is Kilwa, a 308 MW combined-cycle gas turbine (CCGT) presently under negotiation, for which the target total unit cost should not be more than \$0.08/kWh. Nonetheless, the Kilwa negotiation is still ongoing. As previously indicated, Kilwa was not competitively bid—project sponsors involved retired public servants and one private foreign investor—and it is not yet recognized as a success relative to other IPPs.

Wind East Africa (Singida 100 MW) versus NDC (Singida 50 MW)

In 2004, TANESCO, in collaboration with the Danish government, identified stimulating investment and harnessing Tanzania's wind power as priorities. TANESCO invited any party (through an open, general invitation that does not necessarily fall under the definition of international competitive bidding) to develop wind projects. Five entities came forward, including the precursor to Wind East Africa (Singida, 100 MW), as well as two of the partners that since formed the Singida 50 MW project (namely National Development Corporation [NDC] and Power Pool East Africa Ltd; the third party in the consortium is TANESCO). Initial wind-mapping studies were undertaken by Wind East Africa, though there was little in terms of project development by either the sponsors of Wind East Africa (100 MW) or Singida (50 MW). In 2009, Aldwych International, a U.K.-based private IPP firm with a focus on Africa, joined the Singida 100 MW project.

Momentum picked up, including the engagement of the World Bank and the IFC, which today are involved at several levels in the 100 MW project.

Despite the involvement of Aldwych, the World Bank, and the IFC, the project stalled. Meanwhile, Singida 50 was identified among near-term PPPs for TANESCO.

Delay and hesitation surrounding the wind projects were partly due to the fact that at 11–12 USc/kWh, the cost of power was higher than for power generated with domestic gas (at 6–7 USc/kWh). With more gas expected to come on stream, there was an argument that wind power was not competitive. This argument has less traction now, given the delays in gas infrastructure and contracting. Also, wind would prove significantly less expensive than the EPPs of the recent past and IPTL. While both projects are now progressing, the question arises as to why such extreme delays occurred—almost 12 years and counting since Wind East Africa expressed interest.

Another key feature of the wind story is the relationship between the two projects, with Wind East Africa viewed to be in competition with Singida. There was no reason for the two projects to be pitted against each other for multiple years; they could have instead been phased in one after the other, or undertaken simultaneously.

The wind story provides further evidence that the lessons of the IPTL debacle have not been internalized by key stakeholders. Various factions compete within state agencies, based on vested interests; and transparency remains compromised, despite efforts to embolden the EWURA with regulatory powers.

Future Projects, Public and Private

As private developments are beset with challenges related to planning and other issues, how does the public sphere fare, especially with a cash-strapped utility? Is private investment being crowded out?

As mentioned earlier, TANESCO maintains a dominant share in generation—53 percent of installed capacity, which is skewed by the dominance of EPPs. If EPPs are excluded, TANESCO's installed capacity stands at 64 percent, of which 495 MW have been built since 2000. In addition, and as highlighted earlier, in recent years all new long-term power plants have been or will be built and owned by TANESCO, and PPPs have been identified as the way forward. Thus the trend has been to expand, not curtail, state-owned assets, despite repeated calls for privatization.

Going forward, four of the seven priority generation projects in the near term (that is, to be completed before or by 2018) are expected to be owned by TANESCO with varying degrees of PPPs and associated funding; these four projects are Kinyerezi I–IV (with Kinyerezi I and II specified for government funding and Kinyerezi III and IV identified for PPP funding, with Chinese partnerships)—see table 9.6.

Of the estimated $1.91 billion earmarked for investment in the earlier-noted generation projects, the government is expected to contribute $615 million or approximately 32 percent of the new capacity. Thus while ownership of assets is

Table 9.6 Generation Projects Planned in the Near Term, Tanzania

Ownership	*Project name*	*Capacity (MW)*	*Tech/ fuel*	*Investment (US$, millions)*	*Funding source*
TANESCO	Kinyerezi I	150	OCGT	183.3	GoT
TANESCO	Kinyerezi II	240	CCGT	432	GoT
TANESCO	Kinyerezi III	300	OCGT	389.7	PPP
TANESCO	Kinyerezi IV	450	CCGT	400	PPP
IPP	Kilwa Energy	308	CCGT	365	ETG Power, United Arab Emirates
IPP	Singida	50	Wind	136	National Development Corporation, TANESCO, and Power Pool East Africa Ltd.
IPP	Wind East Africa	100	Wind	285	Aldwych, IFC, Six Telecoms

Source: Authors' compilation, based on NKRA 2013 and data received from TANESCO (January 9, 2015).
Note: 210 MW OCGT cited in NKRA 2013, revised to 308 MW (2015); 210 MW is for OCGT to operate for two years, thereafter expanded to CCGT. CCGT = combined-cycle gas turbine; ETG = Export Trading Group; GoT = Government of Tanzania; IFC = International Finance Corporation; IPP = independent power plant; MW = megawatt; OCGT = open-cycle gas turbine; PPP = public-private partnership; TANESCO = Tanzania Electric Supply Company.

dominated by TANESCO in the near term, funding is supplemented notably by the Chinese (as discussed in greater detail below) and IPPs including local IPP sponsors.

The tariff for each of these projects has yet to be announced. For Kinyerezi I and II, which are financed directly by the government, the government has to determine whether there will be on-lending or equity shares provided to TANESCO. Kinyerezi III and IV, which are PPPs, are still in negotiations and the tariff remains undecided. It has been indicated that for gas-fired plants the total unit cost should not exceed $0.08/kWh; however, this is highly dependent on gas prices and still does not reflect the critical capital component, which calls into question the true efficacy of the publicly procured plant.

It is important to note that as of 2015, Kinyerezi II, III, and IV had encountered delays. The following issues have been cited as impediments: a lack of serious developers, a lack of funding potential, a lack of credit enhancement mechanisms, the viability of the power off-taker (TANESCO), and the availability of certain types of fuel.

There is a direct connection between the near-term projects planned by the government and the phasing out of the EPPs. According to TANESCO officials, "there will be no more EPPs" (TANESCO, personal communication, November 19, 2014). Instead, the use of TANESCO's hydropower plants, Mwanza 60 HFO, and IPTL will fill the gap before the new TANESCO plants come online. But the EPPs are not being fully retired as predicted, and Symbion is still in flux.

Parallel to this expansion, the goal (at least on the books) is to achieve retail competition and the privatization of TANESCO. The year 2024 has been identified for preparing generation and distribution companies for listing and privatization. Thus, state ownership will probably continue in the near term (albeit with a larger portion of supplementary funding), but in the longer term a phasing out of direct public ownership and asset funding is anticipated. Nonetheless, there seems to be a real disconnect between plans and action, and the necessary buy-in to realize the plans.

Further Gas Sector and Power Developments: The Government Looks East

In the meantime, the availability (or not) of domestic natural gas continues to play a pivotal role in determining outcomes in the power sector. The government sought private participation in the development of the Mnazi field for over six years. However, no viable interest was found, due in part to a low level of proven reserves in the field and a limited investment-enabling environment.

Meanwhile the Songo Songo fields were slated for expansion by the private sector to meet the near-term needs of the country's gas supply, approximately 50 million standard cubic feet per day (mmscfd) of gas to power 250–300 MW (single cycle). A deal was negotiated with PAT, the existing developer, for a gas infrastructure expansion in 2011 (which had a tariff approved by EWURA; a signed engineering, procurement, construction [EPC] contract; and financing arranged).

On the cusp of the Songo Songo expansion, Tanzania engaged China to help fund natural gas infrastructure connecting Mnazi Bay and Songo Songo to Dar es Salaam, also known as the National Natural Gas Infrastructure Project (NNGIP). As a result, the government put the Songo Songo expansion on hold and focused on the development of the Mnazi field, which was reconfigured from a private infrastructure project to one led by the public sector. Gas deliveries from Songo Songo were estimated to be able to feed (and had been earmarked for) near-term power generation, even as the government sought longer-term gas supply. This shift, from near-term Songas expansion to the long-term NNGIP, exacerbated a gap that was plugged in part by the continued use of EPPs. Thus, the consequences of this policy decision are far-reaching.

The NNGIP, which includes a 532 km natural gas pipeline from Mtwara to Dar es Salaam and gas-processing plants, was completed in 2015 and should be sufficient to run all the plants in an ideal scenario. Despite its mega capacity of 784 mmscfd (1,002 mmscfd compressed), the Mtwara-Dar pipeline initially had only about 80 mmscfd of gas entering it from Mnazi Bay for a limited period of time, about enough to run 350–450 MW (that is, slightly more than what the Songo Songo expansion could have provided for near-term developments).[30] Most of the gas is expected to be consumed by the existing gas turbine plants (including Kinyerezi I, TANESCO's Jacobsen 120 MW at Ubungo, Siemens gas turbines, and the extended Symbion 40–120 MW, LM6000s and TM2500s).

The following questions arise: Is large infrastructure such as the NNGIP needed? Is there enough gas to flow into the pipeline to start with? Most likely not. Tanzania has an impending need for more gas to fuel new projects (Kinyerezi II–IV, Mtwara 400 MW, and so on), but that has proven to be a challenge to date. For example, there is a long-running dispute between PAT and the TPDC at Songo Songo related to cost-recovery and their existing production-sharing agreement. TANESCO also owed PAT approximately $60 million as of 2Q2016, which prevented it from undertaking further investment in gas development. In recent months, progress has been made (although not yet finalized) on a new gas contract between the parties, and the plan is to expand production from Songo Songo by approximately 100 mmscfd, which could be sufficient to supply around 400 MW of open-cycle gas turbine (OCGT) capacity or 50 percent more if configured for the combined cycle.

It is envisaged that the existing Songo Songo gas infrastructure can accommodate 70 mmscfd in total (it is currently processing approximately 91 mmscfd but will revert back to its design capacity of 70 mmscfd). Any additional volumes beyond this will utilize the NNGIP. Considering that PAT has not yet commenced this new drilling, it was anticipated that these volumes would not be in place before 2Q2016. Also, the significant offshore gas discoveries (of up to 55 Tcf of gas initially in place, GIIP) are promising, but unlikely to be delivered onshore and available for power generation before 2022–24.[31] Regardless, the offshore gas is spread out along the coast and is unlikely to be landed in Mnazi Bay. A proposed LNG terminal will be built farther north, so the NNGIP pipeline may not readily serve the offshore gas without further modifications.

Thus, there is a real possibility that gas supply in the medium term will be insufficient to justify an investment such as the NNGIP. To compound the problem, it should be noted that EWURA played no part in the NNGIP despite it being the largest energy infrastructure project undertaken in the country to date. The project was carried out on an emergency basis, and EWURA was only asked to approve a tariff when construction was nearly completed. The China ExIm loan facility of $2.2 billion was premised on a cost of $3.00 per million British thermal units (MMBtu); however, ultimately, EWURA approved a tariff of $2.14/MMBtu (for gas processing and transportation), and the shortfall of $0.86 was to be made up by the government. By comparison, Songas's gas-processing and transportation tariff is $0.59/MMBtu.[32] Although the pipeline is now almost complete, gas off-take agreements and power plan investments are still to be finalized. This is not a minor point, given the burgeoning gas sector.

Parliament has only recently enacted the corresponding Petroleum Upstream, Midstream, and Downstream Act, which mandates a similar vetting process for the gas sector. Legislation was initiated in 2008, but the act was withheld by the Chief Draftsman's Office, and finally passed on July 5, 2015. The act establishes the Petroleum Upstream Regulatory Authority (PURA), which is to regulate upstream gas and also lay out how competitive bidding is to be carried out. On paper, this looks positive, but the question is whether the laws will be sufficiently enforced to help Tanzania avoid the nontransparent deals of the past. Furthermore, it is anticipated that it will take an additional three years for all subsidiary legislation to be designed, drafted, and enacted.

This is more of a concern given the increasing and changing involvement of new financiers, notably China, in the sector. To date, Chinese capital has not been directly involved in financing power projects in Tanzania. That may soon change. Two of the PPPs identified in the near term and noted earlier, Kinyerezi III and IV, have Chinese equity and debt;[33] Chinese companies have also made major gas discoveries. The real question lies in how Chinese-funded projects will be vetted and regulated and whether the Gas Act will afford both the PURA and EWURA the necessary oversight.

In the near term, among the greatest concerns is the ongoing imbalance of payments. There are presently two China ExIm loans (one with a grace period of seven years ending in June 2020 and another with a grace period of four years ending in June 2017). Since 2013, the government has been paying interest twice a year (July, January). This could last up until 2017, when midterm gas supplies are expected. For now, Tanzania potentially will have a costly gas storage facility in the form of a pipeline.

Finally, industry stakeholders have voiced serious concern about the government's lack of consultation, either with the general public or with businesses that will be directly affected by the Petroleum (Upstream, Midstream, and Downstream) Act, and anticipate that this failure to vet the act will impact adversely on investment in the electricity sector.

Conclusions

BRN has set goals of achieving 10,000 MW of generation capacity by 2025, doubling access rates, increasing efficiency, boosting transparency and financial integrity, and privatizing generation and distribution assets. The plans are admirable and ambitious, but viewed in light of the recent past, it is uncertain whether the government has the requisite capacity to deliver on these objectives. It has repeatedly committed to reforms, but been slow to implement them and has wavered in its commitment to integrate private power sustainably and systematically.

Generally, the sector has suffered from poor governance. Frequent turnover at the MEM has impeded consistent and robust decision making. Planning has become a political exercise; coordination, which is intricately linked to planning, has been poor; interagency fighting has been common; and communication among ministries, stakeholders, and donors has broken down, as during the negotiation of Songas and IPTL.

Private power and its benefits are by no means a forgone conclusion in Tanzania. All new projects in recent years have been or are going to be built by TANESCO, regardless of its financial situation, thus crowding out private sector investment. The push to promote public sector projects is not only the result of vested interests, but also of a general bias against private sector participation that has at times informed decision making in Tanzania.

The issues at stake go beyond the question of private vs. public sector involvement. A lack of competitive procurement and transparent contracting has resulted in costly deals and disputed contracts, with large drains on time and resources lost. Although Songas and IPTL run on different fuels and are not exactly comparable, Songas is clearly the least-cost privately owned supply option in Tanzania; IPTL is the most expensive. IPTL power costs six times more than Songas's power and just a little less than the EPPs' power. Beyond technical considerations, it is apparent that such a large price difference between the two is also due to a lack of competition and the disputes that have affected IPTL procurement. Symbion is another powerful example of a deal initially contracted in a nontransparent manner, with costly and disruptive outcomes, which may only now potentially be mitigated by EWURA oversight.

EWURA has been given the mandate to reject unsolicited proposals, like IPTL, that are not within the Power Sector Master Plan and are not financially viable. However, negotiated deals persist, and noncompetitive procurement remains the preferred method at the governing level.

Incoherent planning, interagency disagreements, vested interests, and noncompetitive practices have unraveled contracts and impeded the timely procurement of generation. As a result, the country has been forced to depend on EPPs and expensive oil-fired generation over the past several years.

The supply of natural gas, which is directly tied to electric power development, looks to be a positive story, though not without uncertainties. Delays in agreements with the private sector may mean that plans materialize only from 2022. Delays in expanding the gas supply have already resulted in costly contingency plans such as EPPs, which in turn have bankrupted TANESCO. Should PAT not conclude its second gas supply agreement with the TPDC in a timely manner and offshore gas be delayed, this could impact the rollout of plants adversely. Gas coming from Mnazi Bay will provide fuel in the short term, but it is critical that more sources be secured. And although EPPs were to be phased out, one has been retained in the short term to make up for delays in gas arriving in Dar es Salaam.

Also, the delay of the Petroleum (Upstream, Midstream, and Downstream) Act, passed in July 2015, left the gas sector with no consistent regulation for seven years. The engagement of Chinese funding ushers in a new wave of development.

To address these challenges, private and public stakeholders alike have called for a commitment to improve governance across Tanzania's gas and power sectors in three main focus areas.

First is to *improve planning and processes* to ensure that plans feed through to decision making. Such improvements need to be institutionalized, and the selection of projects be removed from political appointees' and senior bureaucrats' hands. A clear, dynamic, and realistic vision for the future structure of the sector is in order. This would include a sustained commitment to addressing the dire financial condition of TANESCO to ensure a solvent off-taker.

Second, is to improve the *procurement and contract negotiating processes* carried out by the relevant government and parastatal stakeholders. Developers have reported that negotiating processes are ineffective and cumbersome, which has often led to extensive delays or potential projects being abandoned. Clear, transparent processes and accountability for contracting with IPPs and engaging with any public funds (including that of China ExIm) need to be prioritized.

Third, it is necessary for the government to reestablish its *commitment to contracting with IPPs*. Of late, most new power projects are being built as TANESCO-owned plants; this puts the government's commitment to attracting private capital into doubt, despite repeated statements to the contrary.

It is to be hoped that a secure gas supply will be established, putting an end to Tanzania's costly dependence on imported fuel. Private power has, largely through Songas, helped benchmark the state-owned utility, raised the bar, and provided critical new generation. Other projects, such as IPTL and the EPPs, have proven to be costly experiments, primarily due to planning and procurement failures. Tanzania deserves a new decade of private and public project successes, which are within reach of a united approach.

Annex 9A Cost Comparison, TANESCO and Independent Power Projects

Dividing the total cost in table 9A.1 by the Tanzania Electric Supply Company's (TANESCO's) units generated in 2013—namely, 3,109,117,152 kilowatt-hours (kWh)—comes to $0.10/kWh (with an associated off-grid cost of $0.328, albeit representing only 5 percent of the total generation). Thus, TANESCO's total own-generation grid per unit costs, excluding capital costs, are approximately 60 percent of the average end-user tariff, that is, before adding the requisite transmission and distribution (T&D) costs.

For Songas, the average 2013 monthly figure, including both variable and capacity charges, was equivalent to $5.49 million (excluding value added tax [VAT], which is not a cost to TANESCO, and the disputed loan amount).[34] Divided by the average monthly generation of 110,133,333 kWh, the per kilowatt-hour all-inclusive charge comes to approximately $0.0498. The average variable charge amounts to a fraction of this total cost, namely U.S. cents (USc) 1.2–1.3/kWh (billed in Tanzania shillings, T Sh).[35]

Independent Power Tanzania Ltd. (IPTL) trails the emergency power projects (EPPs) in terms of kilowatt-hours contributed, but it resembles Songas in

Table 9A.1 TANESCO's Own-Generation Costs: Tanzania, 2013

TANESCO	*Cost (US$, millions)*
Fuel and oil	287.60
Natural gas purchase	59.78
Plant maintenance	6.33
Staff costs	12.15
Other administrative costs	6.04
Minus off-grid	*–58.85*
Total	**313.06**

Source: Authors' compilation, based on correspondence with TANESCO stakeholders (2014).
Note: TANESCO = Tanzania Electric Supply Company.

its cost structure, as a traditional independent power project (IPP), and therefore is highlighted here. Capacity charges averaged $0.08/kWh in 2013, almost double Songas's total cost. Of the remaining $0.23 in charges for IPTL, $0.22 is accounted for by the fuel (variable charge); thus the overwhelming cost of IPPs remains the fuel.

Annex 9B IPTL and Songas Project Costs, Tanzania

Table 9B.1 IPTL Project Costs, Tanzania

IPTL	*Project cost (US$, millions)*	*Financing*	
Projected total project cost	163.0		
Actual total project cost (postarbitration)			
EPC contract	98.2	70% debt (at 8.5%)	30% equity
Construction contingency	4.9		
Land	1.0		
Insurance	4.1		
Advisers (lenders, project)	3.0		
Working capital	1.7		
Fuel oil reserve	3.2		
Interest during construction	4.6		
Financing and agency fees	1.9		
Miscellaneous[a]	4.6		
Total project costs for diesel	127.2		
Conversion to natural gas			
Estimate of ICSID	11.6		
2005 estimation of Wartsila	20.0	TANESCO	
Total project costs (postconversion)	**147.2**		

Sources: ICSID, MEM, TANESCO.
Note: EPC = engineering, procurement, and construction; ICSID = International Centre for Settlement of Investment Disputes; IPTL = Independent Power Tanzania Ltd.; MEM = Ministry of Energy and Minerals; TANESCO = Tanzania Electric Supply Company.
a. Miscellaneous includes funds termed "development," "mobilization," and "commitment" fees.

Table 9B.2 Songas Project Costs, Tanzania

Songas	*Project costs (US$, millions)*	*Financing*	
Initial Songas costs			
Gas processing and pipeline	100	70% debt (on-lent by GoT at 7.1%)	30% equity
Assumed loans for turbines 1–4 (106 MW)	45		
Work done on wells	25		
Overhaul/refurbishment and conversion of turbines 1–4	35		
Balance of plant costs[a]	61		
Total for 106 MW project, delivered July 2004	266		

table continues next page

Table 9B.2 Songas Project Costs, Tanzania *(continued)*

Songas	*Project costs (US$, millions)*	*Financing*
Songas expansion		
Turbine 5 (35 MW)	7.1	100% equity (Globeleq)
Turbine 6 (40 MW)	14	
Balance of plant costs for expansion	28.9	
Total for 75 MW expansion	50	(revised down to $45 million)
Total on which (2005/present) capacity charges calculated	316	
Additional Songas costs incurred by GoT		
Drilling of original wells	100	Sunk cost, GoT (concessionary loans 1970s)
AFUDC	103	Treasury (40%), TANESCO (10%), escrow (50%)
Escrow account	50	Surcharge on fuel (used to pay down AFUDC), presently now only $2.5 million
Liquidity facility of 4 months' capacity on 106 MW	16.8	Interest on the escrow
Total additional costs	220	Does not include escrow since used to pay down AFUDC
Total project costs	**536**	

Sources: World Bank Project Appraisal Document (http://www.globalclearinghouse.org/infradev/assets%5C10/documents/Tanzania%20-%20Songo%20Songo%20PAD%20-%20WB%20(2001).pdf), Songas personal interviews, TANESCO, MEM.
Note: AFUDC = allowance for funds used during construction; CDC = Commonwealth Development Corporation; EIB = European Investment Bank; FMO = Netherlands Development Finance Company; GoT = Government of Tanzania; IDA = International Development Association; IPTL = Independent Power Tanzania Ltd.; MEM = Ministry of Energy and Minerals; MW = megawatt; Sida = Swedish International Development Cooperation Agency; TANESCO = Tanzania Electric Supply Company; TDFL = Tanzania Development Finance Company Limited; TPDC = Tanzania Petroleum Development Corporation.
a. Songas equity: total equity for original scope is $60 million—Globeleq ($33.8 million), FMO ($14.6 million), TDFL ($4 million), CDC ($3.6 million), TPDC ($3 million in kind), and TANESCO ($1 million in kind). Songas debt: total debt is $206 million—IDA ($136 million), EIB ($55 million), Sida ($15 million). In reference to the IDA loan, $108 million was sourced from the World Bank Credit 3569-TA. In addition, the old loans from previous credits and grants include $22 million (salvage value) for UGT3 and UGT4 LM600 GE turbines installed at Ubungo in 1995; and $8 million paid out of the Sixth Power Project for the working over of Songo Songo wells in 1996–97. Sida contributed a grant to the government of Tanzania, but the loan to Songas was the equivalent to $15 million (salvage value) for UGT1 and UGT2 ABB GT10A in 1994. Balance of plant costs refers to refurbishment of the plant, building of a warehouse, as well as soft costs, for example, project management, build-up of operation and maintenance, and refinancing of turbines 5 and 6 completed in 2009.

Annex 9C ICSID Tribunal, IPTL

The case brought before the tribunal of the International Centre for Settlement of Investment Disputes (ICSID) involved several phases. In the first phase, the Tanzania Electric Supply Company (TANESCO) attempted to rescind the power purchase agreement (PPA) on the basis of technical issues (namely that medium-speed engines were substituted for slow-speed engines). In April 2000, in the midst of first phase proceedings, TANESCO additionally requested the tribunal to hear corruption charges. The request was refused, as no allegations of bribery had been formally pleaded. In May 2000, the tribunal ruled against rescinding the PPA, but stipulated that the capacity payment be lowered to match actual construction costs. Following the initial ruling, in what may be termed a second phase, TANESCO made additional efforts to rescind the PPA, this time formally raising bribery charges through an ancillary claim. Sworn statements were provided by the permanent secretary of the Ministry of Energy and Minerals (MEM), assistant commissioner for energy (petroleum and gas), and assistant commissioner for energy (electricity). In June, the tribunal ruled that TANESCO could pursue bribery charges, but only within the existing time frame of the final hearing (that is, in one month's time). The tribunal ordered both parties to produce any documents in relation to the charges. The tribunal did not allow wide-ranging interrogations or include a forum to require parties to answer specific questions on bribery allegations.

By July 2000, TANESCO produced some documents to the tribunal but requested an extension of three months as it had not yet completed its bribery investigation. The tribunal disallowed any such extension, but proposed that TANESCO withdraw the bribery charges with the option of raising them later in separate ancillary proceedings after completing its investigation, which the utility never pursued. The tribunal ultimately ruled that: (1) allegations of bribery had failed based on the information presented, (2) capacity charges should be reduced based on actual and reasonable costs incurred, and (3) there had been no breach in the fuel supply, as alleged by TANESCO. The final award, made in May 2001, upheld the PPA signed in 1995, adjusted the capacity charge to $2.6 million per month, and indicated that conversion to natural gas would be as per the original PPA—with the costs of conversion paid by TANESCO (with a benchmark of $11.6 million set) and work to be carried out by Wartsila.

Annex 9D Production-Sharing Agreement, TPDC and PanAfrican Energy

Under the production-sharing agreement (PSA) between the Tanzania Petroleum Development Corporation (TPDC) and PanAfrican Energy Tanzania Limited (PAT), profits are shared on production with respect to "additional gas" only. Additional gas is defined as all gas other than that "protected gas" designated for

Table 9D.1 PSAs between the TPDC and PanAfrican Energy Tanzania Limited

	Share of proven section profit gas revenues (%)	
Average daily sales (mmscfd)	*TPDC*	*PanAfrican Energy Tanzania Limited*
0–20	75	25
>20 ≤ 30	70	30
>30 ≤ 40	65	35
>40 ≤ 50	60	40
>50	45	55

Source: Orca Exploration 2007: 9.
Note: mmscfd = million standard cubic feet per day; PSA = production-sharing agreement; TPDC = Tanzania Petroleum Development Corporation.

Ubungo turbines I–V (150 megawatts, MW), plus the cement factory for the 20-year power purchase agreement (PPA).

Profit sharing for gas in the as-of-yet unproven section of Songo Songo, will, regardless of average daily sales, be divided on the following terms: TPDC, 45 percent; PanAfrican (EastCoast Energy), 55 percent.

Notes

1. A considerable amount of information for this case study was collected directly from private and public sector stakeholders who requested anonymity, including, at times, regarding their organizational affiliation. Efforts are made to identify the date when information was collected by way of personal communication.

   Generation is the primary focus of this case study; it is, however, worth noting that as of 2014, 32 percent of the population had access to electricity (a low rate, but on par with the Sub-Saharan African average of 35 percent, notably the lowest among developing regions in the world) (TANESCO, personal communication, January 15, 2015). The connection rate, meanwhile, is 24 percent for the population (MEM 2014: 2). Under the program "Big Results Now" access rates are projected to double in a decade, along with efficiency, transparency, and financial integrity (MEM 2014: 49).
2. This section is based on "Chapter 2: Tanzania: Learning the Hard Way" (Kapika and Eberhard 2013: 53–58). The author is collaborating with Anton Eberhard, who has given permission to draw freely on relevant material.
3. Tanzania's BRN plan took its cue from Malaysia (as well as Thailand and Vietnam, whose economic development levels in the 1960s were akin to Tanzania's now, before implementing similar programs).
4. Further targets are spelled out for access to electricity and the sector's financial sustainability.
5. Average exchange rate for 2013: $1 = T Sh 1,584.05 (Oanda historical exchange rates, http://www.oanda.com/currency/historical-rates/, accessed December 19, 2014). Thus, the net loss in 2013 was $295 million (up from $112 million in 2012). Meanwhile, accumulated losses as of 2013 stood at $915 million (up from $620 million in 2012). According to the Energy and Water Utilities Regulatory Authority, the audited accounts supersede the Development Policy Operation losses.
6. Songas, which will be described in detail shortly, is part of the Songo Songo gas-to-electricity project, a $316 million project that encompasses the Songas power plant in Dar es Salaam, a natural-gas-processing plant on Songo Songo Island, a 225-kilometer (km) pipeline from the island to Dar es Salaam, and rights to two onshore and three offshore natural gas wells at Songo Songo Island. The gas-processing plant and pipelines were built and are owned by Songas Ltd., a local joint venture company which, following a number of transactions, was formed by the power company, the Commonwealth Development Corporation/Globeleq, TANESCO, the Tanzania Petroleum Development Corporation, and the Tanzania Development Finance Co. Ltd. Globeleq has the controlling interest in the project, including the electric power project (which was expanded by the consortium), and the wells are operated by PanAfrican Energy Tanzania Ltd., a local subsidiary of Orca Exploration Group Inc. Construction of the pipeline network was completed in May 2004, and the project started commercial operation in July 2004. The network transports natural gas to Dar es Salaam, where, apart from the Songas power plant, it is used as the principal

fuel for turbine generators at TANESCO's Ubungo I and II power plants (102 and 105 MW, respectively), as well as its 45 MW Tegeta plant. Other outlets for the gas include the Twiga Cement Factory (Wazo Hill) and an electrification project that generates electricity for villages along the pipeline route.

7. While TANESCO remains the dominant player, Songas supplies between 20 and 25 percent of grid electricity, as seen in the next section.
8. The Songo Songo gas-to-electricity project was initially supposed to be expanded in 2006–07 but was delayed following disagreements on gas pricing. The main expansion—adding new gas-processing trains and pipeline compression—was planned to commence operations in late 2012, but development effectively stopped in 2011. There was a tariff order in April of that year, when the government started developing the National Natural Gas Infrastructure Project, as described in detail later in this chapter. The supply gap was plugged during the term with costly liquid-fueled emergency power plants.
9. The mandate for these regulations was given in Clause 5 of the Electricity Act (2008): "The Authority shall have powers to: (i) award licenses to entities undertaking or seeking to undertake a licensed activity; (ii) approve and enforce tariffs and fees charged by licensees; (iii) approve licensees' terms and conditions of electricity supply; and (iv) approve initiation of the procurement of new electricity supply installations."
10. According to the resource classification standards employed in the petroleum industry, the term "reserves" refers to those volumes of gas that are commercially recoverable from known accumulations (SPE 2011). While not all announced reserve figures adhere to this strict definition, the commerciality tests for gas reserves normally require the existence of an established market, available infrastructure, and an approved field development plan. The term "proved reserves" refers to those reserves that are reasonably certain to be recovered, and "probable reserves" denotes gas volumes that are more likely than not to be recovered. The sum of proved and probable reserves, denoted as 2P reserves, is often considered a "best guess" estimate of ultimate recovery from commercial fields.
11. Based on the average 2012 exchange rate of $1 = T Sh 1,562.41.
12. Annex 9A provides details on how each price was derived by the author.
13. If the capacity charge component of a plant's tariff is U.S. cents (USc) 4/kilowatt-hour (kWh) at 90 percent plant load factor (PLF), it would be USc 24/kWh at 15 percent PLF; that is, the differences in headline tariff arising from the PLF may be substantial.
14. Songo Songo 1 (SS1) was drilled and funded by the Azienda Generale Italiana Petroli (AGIP), which had a production-sharing agreement with the government of Tanzania; SS2, SS3, and SS4 were drilled by the Tanzania Petroleum Development Corporation (TPDC) using financial and technical assistance from the government of India; the rest of the wells (SS5, SS6, SS7, SS8, SS9) were drilled in the 1980s by the TPDC.
15. The following overview is based in part on "Generating Power and Controversy: Understanding Tanzania's Independent Power Projects" (Gratwick, Ghanadan, and Eberhard 2006: 39–56), which provides a detailed account of the development of both Songas and Independent Power Tanzania Ltd.'s (IPTL's) independent power projects (IPPs).
16. Ocelot, the initial investor in the Songo Songo gas-to-electricity project, was replaced by its subsidiary company, Pan Ocean. Pan Ocean sold its shares in the power project

in 2001 to AES, the American power development company, to concentrate exclusively on gas development. In 2004, Pan Ocean spun off its interest in Songo Songo to a separate company, EastCoast Energy, which in April 2007 changed its name to Orca Exploration, but operates under the name PanAfrican Energy Tanzania Limited (PAT).

17. Export of gas and electricity from Tanzania to Kenya was recommended by Hardy BBT Limited; the Songo Songo gas development project (gas for domestic use) was recommended by the National Economic Research Associates, based in the United States.
18. The turbines were a conditional grant to the government of Tanzania, but a loan to TANESCO and whoever inherited or bought the units. The book value of these two turbines amounted to $15 million on the transfer date (August 31, 2004).
19. The World Bank involvement at the time included the Power VI Programme, a $200 million loan to help rehabilitate the Tanzanian electric supply industry under which the Kihansi hydropower station of 180 MW would eventually be developed (it was initially planned for 1995 but came online only in 2000). A key provision of this program was that the World Bank had to be informed of any new investments in the power sector greater than $5 million—a less stringent condition than that spelled out in the Songas loan agreement, which required World Bank approval. The rationale behind this policy, which applies generally to the countries eligible for International Development Association assistance, was to ensure coordination with the World Bank, one of the largest lenders to the sector.
20. This electric power component of the project concept would evolve significantly over the decade 1993–2003, from 60 MW to 151 MW. It was then scaled back to 106 MW before eventually increasing to the present 189 MW. The present scope, including gas infrastructure, is outlined in note 6.
21. Enron put up a proposal but did not submit it in July 1993 (due to a court injunction against the firm). Only two proposals were received—one from the joint venture of Ocelot Energy Inc. and TransCanada Pipelines Limited, and the other from Andrade Gutierrez. The latter had experience in only road infrastructure construction and lacked petroleum exploration skills. Thus, during the clarification period (and after Enron was cleared by a court of law), Andrade Gutierrez and Enron formed a joint venture and resubmitted their proposal (in the form of a clarification addendum) in November 1993 before negotiations started.
22. Due to sensitivities, stakeholder names and organizations have been withheld from this reference. See the first endnote in this case study. Apart from the arbitration proceedings, discussed later, in which corruption figured prominently, an investigation was also conducted to document the corruption, but charges were never brought by the government of Tanzania. Certain stakeholders indicated that the failure to bring charges was due to the fact that “too many were implicated”; others said that “the investigation itself was flawed”; and still others noted that it was “in the best interest of the country not to pursue” the investigation.
23. Annex 9B provides information on the total cost for IPTL and the Songo Songo gas-to-power project.
24. IPTL contends that it briefed TANESCO on the substitution well in advance and that it was designed to enhance the maintenance of the plant.
25. Annex 9C provides additional details on the ICSID tribunal.
26. As referenced in table 9B.2 in annex 9B of this chapter, Songas’s debt was $206 million; IDA, $136 million; EIB, $55 million; and Sida, $15 million. In reference to the IDA

loan, $108 million was sourced from the World Bank Credit 3569-TA. In addition, old loans from previous credit lines and grants included $22 million (salvage value) for UGT3 and UGT4 LM600 GE turbines installed at Ubungo in 1995; and $8 million paid out of the Sixth Power Project for Songo Songo well work-overs in 1996–97. Sida contributed a grant to the government, which was loaned to Songas, and equivalent to $15 million (salvage value) for UGT1 and UGT2 ABB GT10A in 1994.

27. AES's exit from the project was a product of the global downturn in the private power sector and foreign direct investment in general, caused by the Asian and subsequent Latin American financial crises, the aftershocks of 9/11, and the Enron scandal—with which AES was closely associated by the mere fact that it was an American power company. AES also lost significant amounts of money on its investments in imploding markets in South America. With a plummeting stock price, AES was pressed to sell assets, among them Songas. As referenced in table 9B.2 in annex 9B of this chapter, after the AES sale, equity shares and associated financial commitments (expressed in $ million) in Songas were as follows: Globeleq: $33.8 (56 percent); the Dutch development bank (FMO): $14.6 (24 percent); TDFL: $4 (7 percent); CDC: $3.6 (6 percent); TPDC: $3 (5 percent); and TANESCO: $1 (2 percent). This does not reflect the additional $45 million that Globeleq committed to expand the power plant, which was subsequently refinanced in 2009.
28. Sponsors required an offshore escrow facility to cover 100 percent of target equity contributions ahead of the transfer date (July 31, 2001), as an exit strategy if nationalization occurred prior to the construction completion date. The amount in the escrow account was to be reduced to 50 percent on the third anniversary of the transfer date (August 1, 2007) and zero on the sixth anniversary (October 2010). The escrow was to be raised through a surcharge on fuel.
29. In 2008 this conversion cost was pegged at $20 million. By 2014 there was no cost estimate available and no date set for conversion (TANESCO, personal communication, November 2014).
30. While it is anticipated that more reserves may be proven and supplies increased, presently that is not part of the gas contract.
31. The schedule for long-term gas in Mozambique, which is widely regarded as ahead of Tanzania, would suggest that long-term gas for Tanzania is likely to come after 2022.
32. It should be noted that this tariff of $0.59 is levied only on certain third-party gas that is processed and transported by Songas and is not based on the underlying capital base of the gas infrastructure.
33. Singida 50 IPP would also avail Chinese funding via TANESCO's equity portion.
34. The disputed loan amount, described below, effectively gets absorbed by the government and serves as a subsidy to TANESCO. TANESCO does not pay the full charge of Songas's power, which amounted to U.S. cents (USc) 6.79/kilowatt-hour (kWh) in 2013 (and USc 6.28/kWh in 2014). In turn Songas is unable to repay its government loan (which relates to funds on lent from the concessionary World Bank and EIB funds received by the government of Tanzania). Both parties are thus absolved, with the liability remaining with the government. This arrangement has been in place for the past 10 years.
35. Information in this paragraph and the paragraph below it is based on personal communication with TANESCO and Songas through 2014 and 1Q2015, various dates.

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CHAPTER 10

Case Study 5: Power Generation Developments in Uganda

Introduction

Uganda occupies a unique space in the history of power sector reform and investment in Africa. It was the first country to unbundle generation, transmission, and distribution into separate utilities and to offer separate, private concessions for power generation and distribution. Critics said that Uganda's power system was too small to reap the possible benefits that might flow from competition in generation, and more focused management of transmission and distribution (T&D). The years that immediately followed the reforms seemed to bear out the critics' views: the private distribution operator struggled to reduce losses, and there were delays in investments in large new hydropower capacity, resulting in costly dependence on short-term thermal power.

Despite ongoing challenges, Uganda's power sector reforms are now bearing fruit. The performance of the distribution utility has improved. Losses are down, and collections, investment, and connections are up, although access rates remain low. After a torturous start, Uganda concluded the largest private hydropower investment in Africa, the Bujagali plant, built by an independent power project (IPP). Simultaneously, it has attracted a raft of smaller IPP investments, including the innovative competitive bids for small hydropower, biomass, and solar projects solicited under the global energy transfer feed-in tariff (GETFiT) program, which was developed jointly by Uganda's Electricity Regulatory Authority (ERA) and the Kreditanstalt für Wiederaufbau (KfW, German Development Bank). After South Africa, Uganda has the largest number of IPPs in Sub-Saharan Africa and the only other competitively bid grid-connected solar photovoltaic (PV) program.

Alongside these IPP successes, Uganda has now embarked on two large Chinese-funded hydropower projects. Private investment in power is still politically contested, and IPPs are seen locally to be potentially expensive, complex, and time-consuming.

Uganda thus offers much pertinent experience and many valuable lessons in power sector reform, private sector participation, IPPs, competitive bidding, grid-connected renewable energy, and Chinese-supported projects.

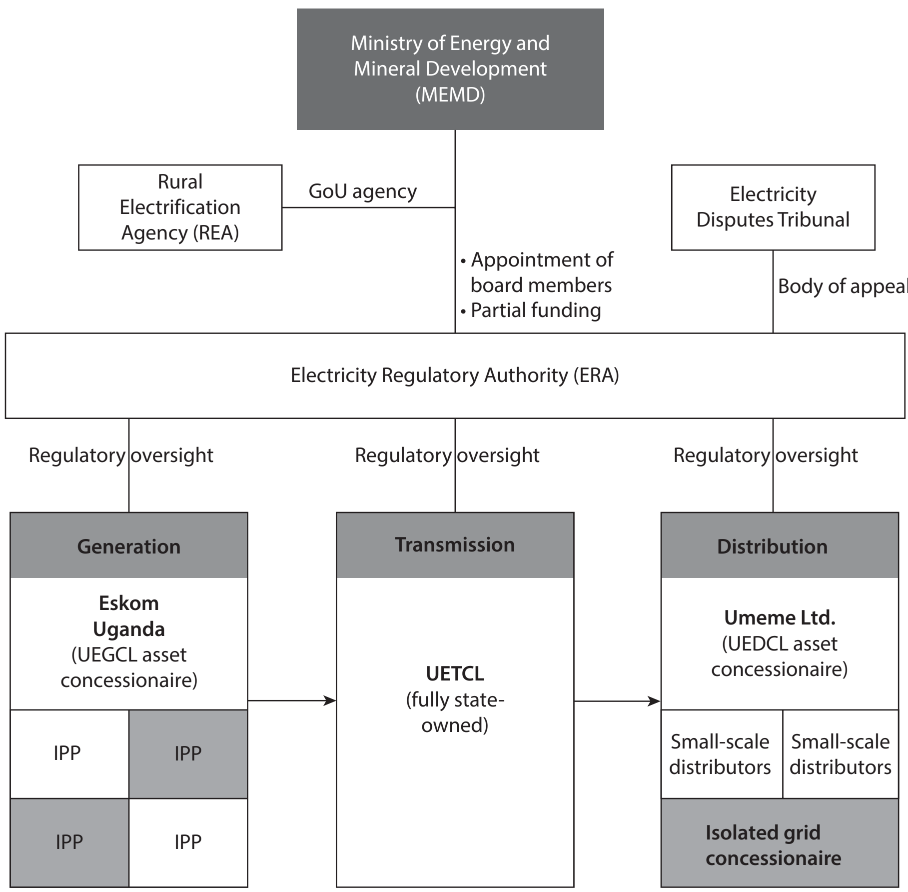
The History and Structure of Uganda's Electricity Sector

The structure and regulatory setup of Uganda's electricity sector are among the most advanced in Sub-Saharan Africa.[1] The sector as it stands today is the result of an ambitious reform process begun in the late 1990s and completed in mid-2000. The structure of the Uganda electricity sector is shown in figure 10.1. The sector's main institutions are profiled in box 10.1.

History of Power Sector Reform

Before the reform, continuous mismanagement and underperformance of the vertically integrated utility, the Uganda Electricity Board (UEB), had resulted in an underfinanced sector, worn-out infrastructure, and poor service.[2] The objectives of a 1998 strategic plan[3] that evolved into the 1999 Electricity Act were fourfold: (1) to improve overall sectoral performance; (2) to enhance both the

Figure 10.1 Structure of Uganda's Power Sector



Source: Compiled by the authors, based on various primary and secondary source data.
Note: GoU = Government of Uganda; IPP = independent power project; UEDCL = Uganda Electricity Distribution Company Ltd.; UEGCL = Uganda Electricity Generation Company Ltd.; UETCL = Uganda Electricity Transmission Company Ltd.

Box 10.1 Major Institutions in Uganda's Power Sector

Ministry of Energy and Mineral Development (MEMD). The MEMD is the focal point for energy policy matters within the Ugandan government. To meet its mandate of overseeing the power sector, the MEMD aims to create an enabling environment for investment through modern policies and appropriate legislation and standards. For public or emergency power generation projects, the MEMD continues to act as a procurement entity, either in its own right or through the sector's parastatals. Procurement for the ongoing Karuma and Isimba hydropower projects is directly handled by the MEMD. In its 2014 Sector Performance Report, the MEMD includes among its priorities (1) increasing electricity generation capacity and transmission networks, and (2) increasing access to modern energy services through rural electrification and renewable energy development.

Electricity Regulatory Authority (ERA). ERA's main responsibilities include the setting of cost-reflective electricity tariffs, which involves proposing and/or approving tariffs for generation, transmission, distribution, bulk supply, and system operation. ERA also defines and monitors technical standards within the sector and enforces adherence to the National Grid Code. It issues and monitors the licenses required to generate, transmit, and distribute power. ERA also sets and reviews renewable energy feed-in tariff (REFiT) levels for generation projects between 1 and 20 megawatts (MW). In its capacity as a tendering authority under Section 33 of the Electricity Act (1999), ERA has recently conducted the first competitive tender for 20 MW of on-grid solar concessions.

Uganda Electricity Generation Company Ltd. (UEGCL). The UEGCL is the holding company for state-owned generation assets. Its two main roles are (1) to supervise and review the performance of the concessionaire, Eskom Uganda Ltd., which operates the Kiira and Nalubaale hydropower plants (HPPs), as well as the thermal-power plant at Namanve; and (2) to negotiate and administer contracts for engineering, procurement, and construction (EPC) and operation and maintenance (O&M) related to mid-tier public projects such as the recently commenced Muzizi HPP and Nyagak III small hydropower (SHP) projects.

Eskom Uganda Ltd. Eskom Uganda Ltd. is a subsidiary of South Africa's utility giant Eskom Holdings SOC Ltd. In 2003, Eskom Uganda was awarded a 20-year concession for the O&M of the UEGCL's generation assets in Jinja (Nalubaale, Kiira).

Uganda Electricity Transmission Company Ltd. (UETCL). State-owned UETCL owns, operates, and plans Uganda's medium- and high-voltage transmission infrastructure (>33 kilovolts, kV), procuring necessary equipment and facilities in its own name. It also functions as the system operator, bulk single buyer (and hence signatory of all power purchase agreements, PPAs), and dispatcher for almost all electricity generated in Uganda. (The electricity generated in isolated grids is excluded. Furthermore, the Electricity Act allows for direct sale from generators to small energy cooperatives.)

Uganda Electricity Distribution Company Ltd. (UEDCL). The UEDCL, the holding company for state-owned distribution assets, administers and supervisors the private distribution concession agreement (presently held by Umeme, discussed next). The UEDCL also operates a small number of mini-grids.

box continues next page

Box 10.1 Major Institutions in Uganda's Power Sector *(continued)*

Umeme Ltd. Umeme Ltd., the major privately owned electricity distributor in Uganda, won the 20-year concession for operating the UEDCL's main distribution network in 2005. Umeme Ltd. purchases electricity at a bulk tariff from the UETCL and sells it as a retailer to roughly 575,000 customers. Industrial and government customers account for about 70 percent of the utility's annual revenue. (The Ugandan government has accrued an account deficit of roughly $42 million, which has led Umeme Ltd., in line with the concession agreement, to withhold equivalent payments to the UETCL.)

Source: Compiled by the authors, based on various primary and secondary source data.

economic and environmental sustainability of the sector; (3) to foster energy security; and (4) to open the sector to private investment, especially in generation and distribution. The National Energy Policy of 2002 reinforced these comprehensive sector reforms and reemphasized the importance of attracting private investment into the Ugandan energy sector. Proposing measures to attract more private capital and international developers into the sector, the National Energy Policy called for using incentives such as loans on concessionary terms, government guarantees, and "smart subsidies" (grants) for power sector investments.

The core reform and restructuring process initiated by the 1999 legislation lasted six years. Between 1999 and 2005, the UEB was unbundled into the generation, transmission, and distribution companies known as the Uganda Electricity Generation Company Ltd. (UEGCL), Uganda Electricity Transmission Company Ltd. (UETCL), and Uganda Electricity Distribution Company Ltd. (UEDCL). The plan enshrined in the legislation also provided for some key early strategies for the expansion of all three subsectors, with varying degrees of private sector participation. The Ugandan government conducted international competitive tenders for the operation and maintenance (O&M) of generation plants and for the leasing of distribution assets. The tendering process resulted in the award of concessions to Eskom Uganda Ltd. in 2003 and to Umeme Ltd. in 2005.[4] Through these concessions, the government increased the financing base for rehabilitation and incentivized good performance in accordance with private sector benchmarks. The UETCL remained a publicly operated transmission utility but unraveled due to immediate governmental influence and was reorganized with an operationally independent board and a corporate management structure. Despite plans to privatize the UETCL, the government has so far refrained from doing so. Uganda has, meanwhile, maintained the single-buyer model, and the UETCL is still the sole off-taker of all electricity entering the main grid.

The reform process was supported by a credit from the International Development Association (IDA) of the World Bank. The credit was extended under a program that promoted divestiture and restructuring of state-owned enterprises (SOEs), greater private sector participation, and strengthening of regulatory frameworks. A supplementary IDA contingent credit of $5.5 million was made to support a liquidity facility for Umeme. The World Bank Group's (WBG's) Multilateral Investment Guarantee Agency (MIGA) extended insurance coverage for up to $45 million in equity and shareholder loans to cover transfer restrictions, expropriation, war and civil disturbances, and breach of contract.

The IDA contingent credit acted as a guarantee, giving Umeme the right to be compensated for losses of revenue stemming from the following potential events: (1) failure by ERA to approve tariff adjustments according to the tariff methodology in the distribution and supply license; (2) nonpayment of power bills by governmental entities; (3) early termination of the concession by Umeme resulting from a breach of the privatization agreements by the national government or its entities during the first 18 months of the concession; (4) early termination of the concession by Umeme for reasons related to the company during the first 18 months (entitling Umeme to return of half its initial investment of $5 million); (5) and refunds by Umeme of the concession fees and security deposits paid by customers of UEDCL before the transfer date; (6) termination of the concession in the event of default or *force majeure* (including for political reasons) by the UEDCL or the government of Uganda.

The IDA contingent credit was the first recorded instance of a development finance institution (DFI) covering regulatory risk.

The security package consisted of the following support measures: (1) monthly lease rents, (2) an escrow account, (3) a letter of credit (LC) facility, and (4) an IDA contingent credit to backstop the latter. The LC facility and the IDA contingent credit were accessible to Umeme only for the first three events just listed and only after other mitigation measures (from monthly lease rents and the escrow account) were exhausted.

Under the distribution concession, the concessionaire was contractually obligated to invest a minimum of $65 million by the end of the fifth year. With that, the company was expected to provide up to 60,000 new connections, reduce total losses from 33 percent to 28 percent, and improve collection rates from 75 percent to 92.5 percent.

An amendment to the distribution concession was signed in 2006.[5] Umeme made progress in expanding connections and investment, but losses remained stubbornly high, oscillating with no discernible pattern between 31 and 35 percent.

In 2006, seven years after the start of the sector restructuring process, the supply deficit was in the range of 90 to 210 megawatts (MW) (USAID 2013), entailing extensive load shedding. It had been envisaged that the 250 MW Bujagali hydropower plant (HPP) downstream from the existing Nalubaale and Kiira dams would be on-grid by this date. However, allegations of corruption resulted in the collapse of the contracted consortium led by U.S.-based AES Corporation and to the abandonment of the project in 2004. The relaunch of the procurement process in 2005 was then supervised by the WBG and the European Investment Bank (EIB). The plant was completed in 2012. Arguably, this large investment was facilitated by the presence of a private distribution concession, which instilled confidence that, over time, collections and loss-reduction initiatives would be sustained.

In total, the Bujagali HPP procurement preparation and implementation, and the subsequent construction process, took seven years, during which the electricity supply shortage had to be mitigated by expensive thermal power. At peak times in 2011–12, Uganda had 200 MW of generation facilities under operation, using heavy fuel oil (HFO) and diesel. Operation of these facilities first drained the UETCL's capital savings and then affected the single buyer's liquidity. In addition, the depreciation of the Uganda shilling, which fell 25 percent against the U.S. dollar in 2011 alone, and the depletion of the World Bank's partial financing of the thermal-based power production costs, led to a severe shortfall of funding in the power sector. Until fiscal year (FY) 2011/12, the government of Uganda paid a cumulative total of $623 million in subsidies to the UETCL, at its peak, roughly 7 percent of the national budget per year.[6] In FY2010/11 alone, the Ugandan government paid more than $170 million of direct subsidy to the UETCL, almost equivalent to the government's annual budget allocations for health (SE4ALL 2012). Furthermore, in 2005, the government also had to compensate Umeme Ltd. for not being able to supply the amount of energy specified in the concession agreement, an additional drain on the national budget. Despite these severe and unsustainable circumstances, the government did not permit ERA to increase end-user tariffs to sustainable levels until 2012.[7] Electricity tariffs had been increased twice in 2006—by 41 percent and 35 percent, respectively (Dhalla 2011). Since then, the weighted-average tariff had effectively declined by 6.6 percent in Uganda shilling terms and by 23.2 percent in U.S. dollar terms, the latter being significant because most of Uganda's power sector revenue requirements were denominated in foreign currency. As a result, the weighted-average retail tariff in 2011 was $0.126/kilowatt-hour (kWh), while a fully cost-reflective tariff would have been about twice that, at $0.251/kWh (Dhalla 2011).

In 2012, the government finally took steps to fix an unsustainable sector and remedy the liquidity situation of the UETCL. It supported ERA's request to increase the end-user tariff by a weighted average of 46 percent, which, together with power produced by the Bujagali HPP after October 2012, reduced the pressure on the UETCL's balance sheet.

To stimulate private investment in small-scale renewable energy technologies (RET), which were needed to bridge the anticipated supply gap until major hydropower schemes came online in FY2018/19, ERA conducted a review of feed-in tariffs (FiTs) pertaining to renewable energy in 2012, which led to the adoption of the "Phase 2 REFiT guidelines" and a new attempt to offer cost-reflective RET-specific FiTs for small projects.

With these measures implemented, Uganda appeared prepared to expand generation capacity and improve the overall performance of the sector. Yet, it quickly became clear that problems remained in expanding generation capacity, owing mainly to constraints on cost-reflective tariffs for new projects.[8] Financing and project development costs remained high. In particular, the vital small-scale power projects remained unviable, even under the revised renewable energy feed-in tariff (REFiT) scheme. Another period of thermal-based power supply and depleting subsidies loomed.

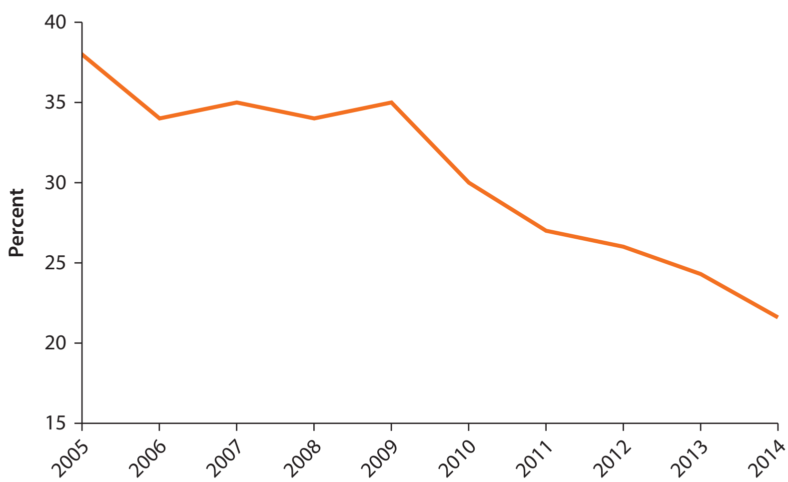
The government responded to this crisis in two ways. First, the procurement of roughly 800 MW of large hydropower capacity was fast-tracked. Financing and construction deals were reached with China's ExIm Bank and Chinese contractors. Second, for small-scale projects, ERA, in cooperation with KfW, developed and implemented the GETFiT program.[9] Through this facility, up to 20 IPPs of various RET generation types totaling 150 MW of generation capacity were targeted for commercial operation between 2015 and 2018.

By late 2014, it seemed that the Ugandan energy sector had overcome the most demanding phase of a market transition and was sufficiently prepared for future challenges, in particular with regard to the procurement of generation capacity. The increase in investor interest in Uganda is tangible, and Sub-Saharan African partners and stakeholders closely monitor ERA's activities. Not surprisingly, *Bloomberg New Energy Finance* ranked the country 10th in a 2013 global survey of the investment climate in 55 emerging economies (and third in Africa, after the significantly larger African economies of South Africa and Kenya).[10]

Umeme's performance has improved steadily in recent years, as indicated in figures 10.2–10.5. Umeme now faces new loss-reduction targets—from 23.4 percent in 2014 to 14.9 percent in 2018.

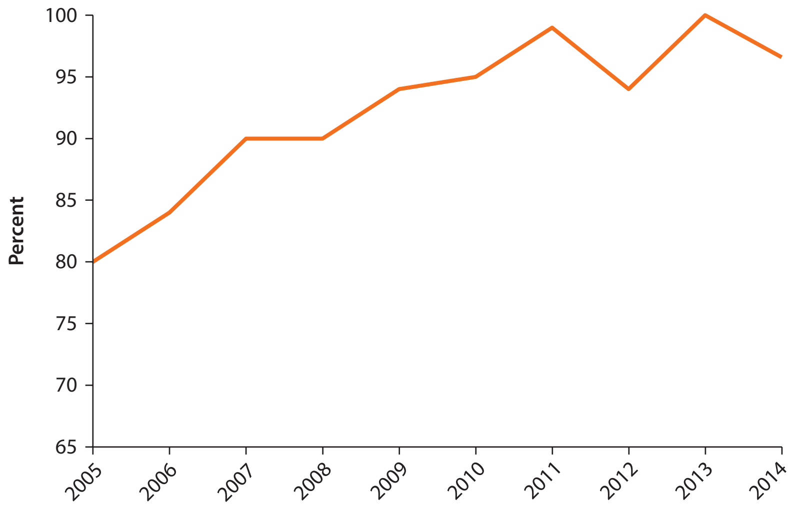
Umeme listed its shares on the Uganda Securities Exchange through an initial public offering in 2012. More than 6,000 Ugandans bought the firm's stock, as did African institutional investors, foreign equity funds, and venture capital funds. Funds raised from the stock offering were used to reduce the company's interest-bearing debt and enabled Umeme to secure additional commercial debt over the next few years to help finance its expansion strategy. Umeme's shares were cross-listed at the Nairobi Securities Exchange in 2013. The strategic investor Actis, previously known as Globeleq, became a minority shareholder by

Figure 10.2 Umeme Energy Losses: Uganda, 2005–14



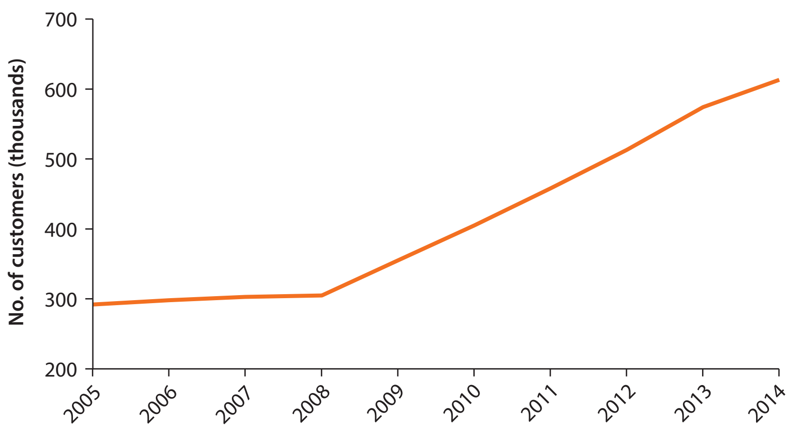
Source: World Bank 2014.

Figure 10.3 Umeme Collection Rates: Uganda, 2005–14



Source: World Bank 2014.

Figure 10.4 Umeme Customers: Uganda, 2005–14

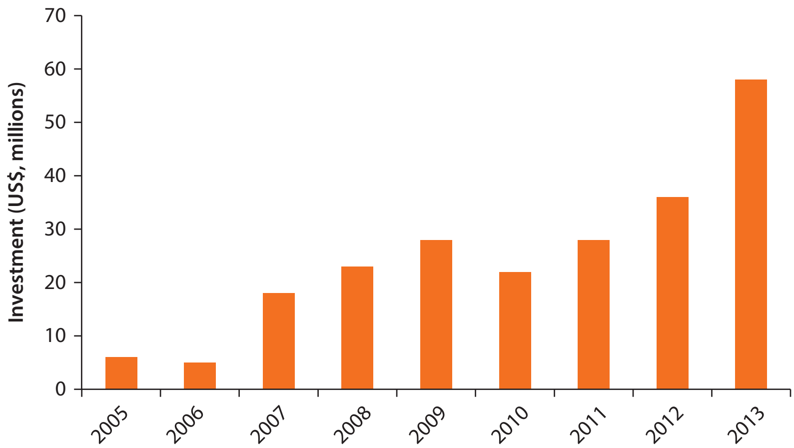


Source: World Bank 2014.

reducing its equity participation to 14 percent in May 2014. By May 2014, the top shareholders of Umeme were Investec Asset Management, Actis, the National Social Security Fund, Farallon Capital, Coronation Funds, Allan Gray Africa Funds, the International Finance Corporation (IFC, WBG), Utilico Emerging Markets, Patrick Bitature, and Everest Capital.

However, it has not been all smooth sailing. In 2006, Umeme shareholders were ready to exercise their termination rights due to the power supply crisis. The IDA strongly encouraged both parties to renegotiate the concession and

Figure 10.5 Umeme Investment: Uganda, 2005–13



Source: World Bank 2014.

extended its guarantee in support of the resulting restructuring. The IDA also provided financial support to help Uganda finance emergency power to mitigate supply shortages. In 2008, Umeme and the Ugandan government entered into a dispute concerning the compliance of both parties with contractual obligations. While the government acknowledged that it could have been more supportive of Umeme's efforts to reduce nontechnical losses, its perception was that Umeme's management was not doing enough in accelerating efforts in other areas. In response, Umeme brought in a new management team. In early 2009 a new minister of energy and some members of parliament tried to unilaterally terminate Umeme's concession on grounds of nonperformance. The IDA joined forces with the MIGA and IFC to prepare a report that showed the progress and conditions of Uganda's distribution network since the onset of the concession. The Ugandan government acknowledged, at the highest level, that despite "mixed" performance in certain areas, Umeme had improved distribution services overall. Subsequently a new minister of energy was appointed. In FY2011/12 a deadlock in negotiations over performance targets for the 2013–18 regulatory period was eventually resolved with the aid of an independent adviser to ERA and support from the WBG (World Bank 2014).

However, tariff challenges remain. With an estimated annual increase in demand of 10–12 percent through 2020, and higher beyond, Uganda needs to embark on proactive planning for additional generation capacity. The export of promising oil and gas resources might generate investment funds for power projects in the medium term. However, it remains essential that Uganda continue to pursue the bold course charted during the first decade of this century.

Power Sector Planning, Allocation, Procurement, and Contracting

The Electricity Act (1999) and pertinent sector documents (such as the 2002 Energy Policy, the 2007 Renewable Energy Policy, and various joint sector reports) affirm that the government, in particular the Ministry of Energy and Mineral Development (MEMD), holds primary responsibility for the expansion of generation capacity. Although Uganda's electricity sector has been fully unbundled, all generation, transmission, and distribution assets remain ultimately under state ownership. O&M of the state-owned generation facilities and the main distribution grid, however, have been concessioned to private companies (see figure 10.1).

The MEMD's electricity sector functions, as described in the *2014 Sector Performance Report* and the 2007 Renewable Energy Policy, bear striking similarities to Section 11 of the Electricity Act (1999), which outlines the responsibilities of ERA, the regulator. ERA understands its role as the promoter of frameworks that stimulate investment and competition and as the "guardian" and facilitator of the least-cost development path for future resource development. In broader terms, ERA aims to increase the quantity, reliability, and diversity of generation (interview with Benon Mutambi, CEO, ERA, April 2015). Beyond the supply side, ERA also claims responsibility for providing cost-efficient and sustainable frameworks to ensure financial resources for further reinforcements and extensions of the T&D grid.

The responsibilities for procuring new power generation capacity are effectively split among three actors: the MEMD, UEGCL, and ERA. Yet there is no doubt that the MEMD remains the chief forum for the development of political consensus and for decisions on the implementation of policies governing the broad electricity sector. The MEMD's Energy Resources Department is responsible for forecasting demand and supply at the national level. It is within the MEMD that policy proposals and inputs of sector stakeholders such as the Rural Electrification Agency (REA) and ERA are coordinated and blended into a national policy framework.

ERA has, however, exercised its role as the facilitator of private sector development to set up market mechanisms and competition. This has led to an increase of its leverage and importance in recent years, as evidenced by the 2012 hike in end-user tariffs, which was advocated by ERA to encourage further investments in generation capacity and other sectorial necessities. Furthermore, the introduction of a quarterly automatic adjustment mechanism for end-user tariffs, which was promoted by ERA for years and which effectively floats electricity prices on the basis of macroeconomic parameters (beyond political control), could not have occurred without ERA's strong standing in the sector.

As the sector's data collection hub, ERA has unrivaled insight into the market subsectors and their respective dynamics. Armed with this knowledge, it is the de facto policy adviser for all other sector stakeholders, including the MEMD, in matters involving data and strategy. Beyond these advisory responsibilities, ERA autonomously originates sector policy in two ways. First, it is the driver behind the development and monitoring of the least-cost generation path as stipulated in the Power Sector Investment Plan (PSIP), even though that path must be officially adopted by the MEMD. Second, it affects sector planning by shaping the future energy mix in the country, specifically by determining and enforcing capacity targets and limits (as seen under the REFiT scheme) and by licensing generation projects based on marginal cost.

Planning and procurement are guided by the Renewable Energy Policy of 2007 and the 2011 PSIP. The latter expands on the sector strategies mandated in the 2010 National Development Plan for the period 2010/11 to 2014/15 (Government of Uganda 2010). It encompasses investment proposals for generation through 2030 and prioritizes projects along the trajectories of supply reliability and least costs (discounted) (MEMD 2011). In the PSIP, the MEMD estimated that the total capital investment cost for generation to meet demand through 2030 would be nearly $5.5 billion.[11] In the proposed scenario (which has not yet been realized), the government was to provide, in the medium term, equity of more than $1.6 billion. The MEMD has opened the public space for Chinese-funded investments and development as well as attempted to create an attractive environment for private investment and development.

The first procurements of generation capacity following the 1999 reforms were the Bujagali HPP and various thermal power projects, all implemented between 2004 and 2010. Bujagali HPP was initially undertaken by the MEMD, which awarded the contract to the AES consortium. The award process was implemented under internal and external pressures resulting from a severe supply deficit, economic woes, and turmoil in the sector in the years following the reforms. The procurement of thermal power was realized by a multitude of players using a variety of procurement arrangements. The MEMD, through the UETCL, awarded the first contract to Aggreko in 2005 after competitive bidding. The second award to Aggreko for the Kiira project in 2005/06 was effectively the result of a direct negotiation process, one accompanied by allegations of secretiveness and mismanagement.[12] The 2008 procurement of the Mutundwe project was partially supported by the IDA and implemented by the UETCL on behalf of the MEMD and World Bank. The contract for the Namanve plant, awarded to Jacobsen of Norway in 2008, was the result of a competitive procurement process under the Electricity Act, but this time implemented by ERA. The last thermal project followed a classic IPP model: Electro-Maxx's Tororo project resulted from an unsolicited bid process under Section 32 of the Electricity Act (1999).

For IPP-promoted projects across all generation types, ERA can receive unsolicited bids under Section 30 of the Electricity Act (1999) or implement competitive bidding for concessions pursuant to Section 33. For all unsolicited bids, ERA is the lead entity and guides and monitors the planning and implementation of projects. For nonstandard tender procedures, such as the recently closed competitive bidding for solar generation jointly implemented with KfW and the GETFiT facility,[13] ERA can utilize the expertise of external consultants in compliance with Section 15 of the 1999 Act. The procurement processes hosted by ERA follow the legislative framework set forth in Sections 30–52 of the act, which deal with the licensing and permitting. For both unsolicited proposals and competitive bids, ERA initiates the procurement and conducts the necessary due diligence for the award of permits and licenses and then monitors the performance of the IPPs. For all RET-based projects having a capacity of between 1 MW and 20 MW, ERA is also in charge of the REFiT scheme, which offers predefined, technology-specific off-take prices per kilowatt-hour over the 20-year lifetime of the power purchase agreement (PPA). After some further minor increases,[14] the terms of REFiTs are as shown in table 10.1.

For the two currently implemented large-scale hydropower projects—Karuma (600 MW) and Isimba (183 MW)—the MEMD took the lead in procurement starting in 2005/06, when Karuma was earmarked for implementation as a publicly procured engineering, procurement, and construction (EPC) project.[15] The first tenders went out in 2006. However, the process of obtaining financing and a contractor for the project gained decisive momentum only after 2010.

In this context, it is noteworthy that the 1999 Act does not foresee any *direct* role for the Ugandan government in developing generation projects or procuring new capacity. The sector reforms of 1998–99 and the subsequent act stipulated the development of IPPs (through unsolicited bids or competitive bidding for concessions) under the direction of ERA, as well as public EPC procurement through parastatals such as the UEGCL and UETCL. The act contemplated only "persons" as legitimate applicants for a permit to conduct feasibility studies (Section 30) or as holders of a generation license (Section 34). A person is defined as "any individual, firm, company, association, partnership or body or persons, whether incorporated or not."

Whereas this clause, narrowly construed, stipulates only that the MEMD cannot be the holder of a permit or license, it is noteworthy that the ministry is otherwise not mentioned once in the respective section of the act. From this, one may conclude, as other stakeholders affected by the act have done, that the development and procurement of generation capacity are not the role of government, but exclusively of private actors and incorporated parastatals.[16]

The emergence of direct procurement by the MEMD has thus been considered "a challenge for the integrity of sector structures."[17] Although both the

Table 10.1 REFiT Overview: Uganda, as of January 2015

Renewable energy technology	*Tariff (US$/kWh)*	*O&M (%)*[a]	*Cumulative capacity limits (MW)*				*Payment period (years)*
			2013	*2014*	*2015*	*2016*	
Hydro (9 ><= 20 MW)	0.085	7.61	30	90	135	180	20
Hydro (1 ><= 9 MW	Linear tariff[b]	7.24	30	75	105	135	20
Hydro (500 kW ><= 1 MW)	0.115	7.08	1	2	2.5	5.5	20
Bagasse	0.095	22.65	30	70	95	120	20
Biomass	0.103	16.23	5	15	25	45	20
Biogas	0.115	19.23	5	15	25	45	20
Landfill gas	0.089	19.71	0	10	20	40	20
Geothermal	0.077	4.29	10	30	50	75	20
Wind	0.124	6.34	25	75	100	150	20
Solar	0.11	n.a.	n.a.	n.a.	n.a.	n.a.	20

Source: Compiled by the authors, based on various primary and secondary source data.
Note: kW = kilowatt; kWh = kilowatt-hour; MW = megawatt; O&M = operation and maintenance; REFiT = renewable energy feed-in tariff; USc = US cents; n.a. = not applicable.
a. The REFiT scheme also allows for an inflation indexation of the O&M share on an annual basis.
b. Linear tariff for small hydro computed as a regressive allocation of costs with increase in plant size, range USc 10.9 (1 MW) to USc 7.9 (Uganda REFiT guidelines, www.era.co.ug).

Karuma and Isimba HPPs will be transferred to the UEGCL ownership after reaching financial close, and thus brought into compliance with the provisions of the act, ERA's regulation of these projects will remain marginal. The conclusion of financing agreements for the projects implies that tariffs have already been negotiated, which precludes ERA from exercising its mandate and obligations under Section 76 of the act. Furthermore, as the design of the projects has been determined, ERA will have difficulty monitoring and enforcing compliance with technical and quality standards.

The UEGCL and, in the past also the UETCL, are the parastatal entities that regularly procure generation capacity for the government, often in cooperation with development partners or international financial institutions and on the basis of concessional official development assistance (ODA) or grant finance. The procurements presently under implementation by the UEGCL are the Muzizi HPP (46 MW) and Nyagak III small hydropower (SHP) project (4.3 MW). The UEGCL is also the governmental body designated to participate in public-private partnerships (PPPs). Nyagak III SHP is the first project currently considered a PPP, and its process of identifying a private partner recently closed, despite the fact that the PPP legislation has been pending in parliament since early 2012. Projects realized by the UEGCL are also subject to full regulatory scrutiny by ERA.

Incentive Frameworks

During the sector crisis of the late 2000s, the government introduced an array of incentives to facilitate investments in the power sector (table 10.2). Beyond the FiT for small-scale RET, the government implemented other measures

Table 10.2 Overview of Available Tax Incentives for Power Generation Investments, Uganda

Type	*Details*
Initial capital allowances	Initial allowance on plant and machinery of 50–75 percent[a]
	Start-up cost spread over four years (25 percent per year)
	Initial allowance of 20 percent on hotels, hospitals, and industrial buildings
	Deductible annual allowances (depreciable assets) of 20–40 percent
VAT	Exemptions for hydro (full/public and IPP[b])
	Partial exemptions for solar (sole-purpose electromechanical equipment only)
Import duty/tax	Duty- and tax-free import of plant and machinery
	Rebate of fuel duties
	Stamp duty exemption
	Exemptions from withholding on plant and machinery, scholastic materials, human and animal drugs, and raw materials
	Ten-year tax holiday
Repatriation of profits	No limits and no tax on repatriation of profits or dividends

Source: Compiled by the authors, based on various primary and secondary source data.
Note: IPP = independent power project; VAT = value added tax.
a. Revoked in the tax reforms of 2014. Now plant and equipment must qualify under the Income Tax Act for accelerated depreciation, with a maximum annual deductible of 20 percent.
b. After the tax reforms of 2014, costs incurred during the feasibility stage are no longer exempted from the value added tax.

Table 10.3 Risk Mitigation and Investment Incentives for Thermal and RET Projects, Uganda

Risk	*Thermal*	*RET (2008–12)*	*RET/GETFiT (since 2012)*
Nonpayment by sole off-taker resulting in liquidity shortage	Governmental/World Bank guarantees for UETCL payments Implementation agreements	Governmental guarantees for UETCL payments Implementation agreements (some)	Governmental/World Bank guarantee for UETCL payments Implementation agreements (standardized) Up-front payment of GETFiT subsidy for supported projects
Dispatch	Capacity payments	Capacity payments (large) Take-or-pay arrangements for small-scale projects	Take-or-pay arrangements Interconnection support (policy, development partner grant or concessional finance support for power infrastructure)
Fuel, hydrology	Fuel cost pass-through to UETCL/ government of Uganda Joint fuel procurement arrangement with Ugandan government for some projects	None	None by Ugandan government Limited hydrology risk sharing under GETFiT financing agreements
Termination, government default, expropriation	Implementation agreements	Implementation agreements (some)	Implementation agreements (standardized) Direct agreements between lenders and Ugandan government World Bank partial risk guarantee

Source: Compiled by the authors, based on various primary and secondary source data.
Note: GETFiT = global energy transfer feed-in tariff; RET = renewable energy technology; UETCL = Uganda Electricity Transmission Company Ltd.

specifically targeting RET and thermal-based power investments, such as take-or-pay arrangements and capacity deals. Additional supporting measures, such as sovereign guarantees, were introduced, and tax exemptions for general investments were extended to the power generation subsector.

In its Sector Performance Report for 2014, the government confirmed its willingness to promote power generation across all available technologies. However, whereas RET development has dedicated policies, the thermal sector has not benefitted from such specific proposals, presumably because it lacks donor funding and support. This has not impeded thermal power development in Uganda in the past. However, the implementation of further projects is not likely to materialize until the timeline for development of Uganda's petroleum potential becomes clearer (a topic discussed further on).

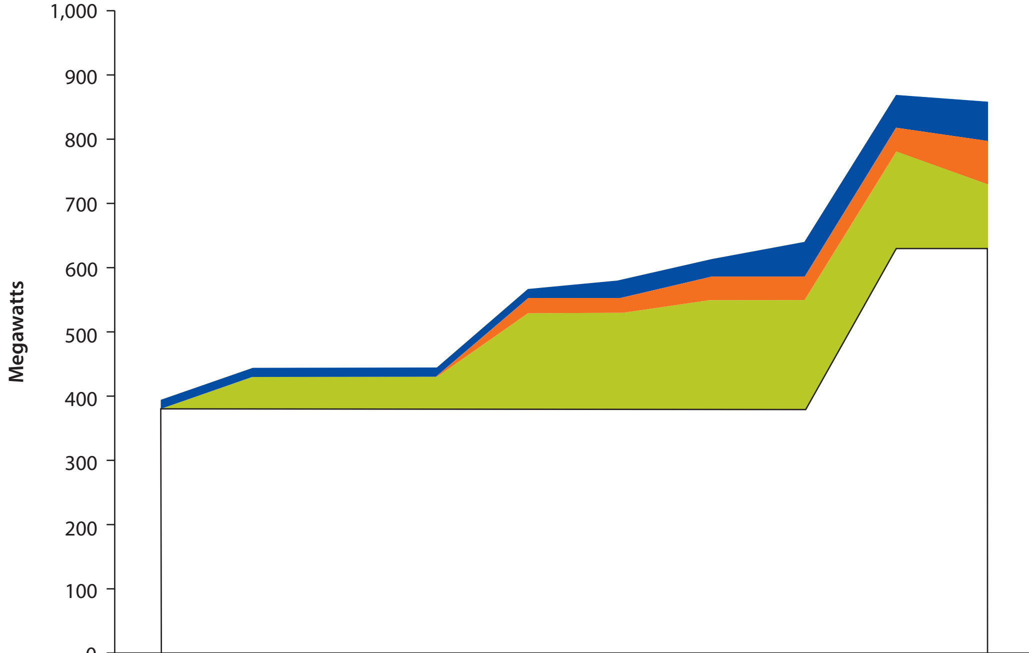
For RET, as previously noted, the government and its entities have developed a more comprehensive policy, accompanied by the risk mitigation instruments and incentive mechanisms detailed in table 10.3.

Current Attributes and Recent Performance of the Electricity Sector

Installed Generation Capacity

Large hydropower projects accounted for 74 percent of Uganda's power capacity in 2013, followed by thermal plants (12 percent). Bagasse and small HPPs

Figure 10.6 Total Capacity, by Technology: Uganda, 2004–13



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Small hydro	15.5	15.5	15.5	15.5	15.5	28.5	28.5	52.9	52.9	61.9
Bagasse	0	0	0	0	22	22	36.5	36.5	36.5	66.5
Thermal	0	50	50	50	150	150	170	170	150	100
Large hydro	380	380	380	380	380	380	380	380	630	630

Source: Compiled by the authors, based on various primary and secondary source data.

supplied roughly equal shares of the remainder (figure 10.6). Details on Uganda's power plants are shown in table 10.4.

Electricity production in 2013 was split more or less evenly between IPPs (1.492 gigawatt-hours, GWh) and public projects (1.239 GWh), with a small share of thermal emergency capacity (figure 10.7). (All conventional thermal capacity in Uganda—the Namanve and Tororo plants—is currently operated as emergency or standby capacity.)

IPP production increased dramatically with the commissioning of the Bujagali HPP in 2012, which reduced the need for emergency power generation.

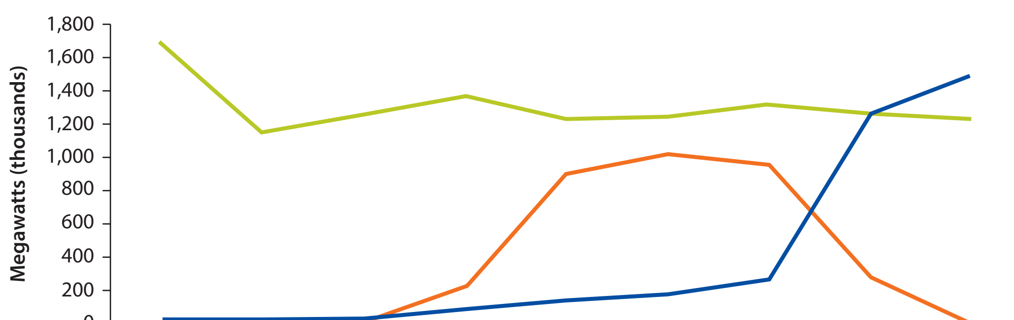
Figures 10.8 and 10.9, viewed together, reveal the expected evolution in ownership and funding of Uganda's generation assets through 2020. The advent of the Bujagali HPP resulted in a roughly even share of power generation between the public utility and IPPs. The share of public projects will grow again (to roughly 75 percent of total installed capacity by 2020) with the completion of the current Chinese-funded hydropower investments, which are discussed further on.

Table 10.4 Uganda's Power Plants

Owner/operation	*Plant*	*Ownership (public, PPP, or IPP)*	*Type*	*Installed MW (noncaptive)*	*Peak (and average) capacity to grid*	*Comment*
UEGCL/Eskom Uganda	Nalubaale	Public	Hydro	180	220 (140)	Capacity shown is for both projects
	Kiira			200		
BEL Ltd.	Bujagali	IPP	Hydro	250	170	
Jacobsen	Namanve	IPP	Thermal (diesel/ HFO)	50	50	Emergency plants (2013)
Electro-Maxx	Tororo	IPP		50	50	
SAEMS	Mpanga	IPP	Small hydro	18	9	
TrønderEnergi	Bugoye	IPP		13	9	
Hydromax	Buseruka	IPP		9.0	4	
Eco Power	Ishasha	IPP		6.4	3	
Mubuku III	KCCL	IPP		10.5 (7.5)	3	
Mubuku I	Kilembe Mines	IPP		5.4	2	
Kakira Sugar Works	Kakira	IPP	Cogeneration (bagasse)	52 (32)	32	
Kinyara Sugar Ltd.	Kinyara Cogen	IPP		14.5 (7.5)	3	
West Nile Rural Electrification Company	Nyagak I	IPP	Small hydro	3.4	n.a.	Isolated grid
Oil Palm Uganda		PPP/ ODA	Solar/thermal hybrid	1.6	n.a.	
Total MW				**858.4**		

Source: Compiled by the authors, based on various primary and secondary source data.
Note: HFO = heavy fuel oil; IPP = independent power project; KCCL = Kasese Cobalt Company Ltd.; MW = megawatt; ODA = official development assistance (concessional aid); PPP = public-private partnership; SAEMS = South Asia Energy Management Systems; UEGCL = Uganda Electricity Generation Company Ltd.; n.a. = not applicable.

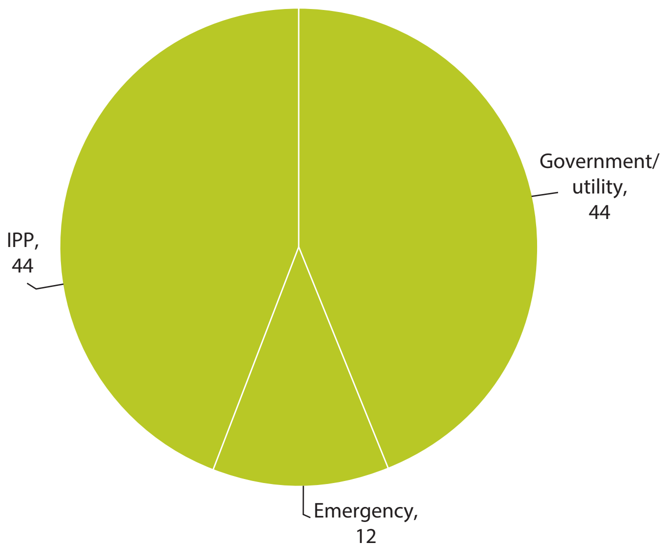
Figure 10.7 Sources of Electricity Sold to UETCL: Uganda, 2005–13



	2005	2006	2007	2008	2009	2010	2011	2012	2013
IPP	22,310	30,021	32,687	88,474	138,377	177,202	260,359	1,272,351	1,492,036
Emergency	140.91	370.08	556.27	217,104.71	896,610.26	1,020,278.08	957,992.91	275,292.78	1.40
Government	1,702,690	1,160,456	1,263,544	1,373,444	1,234,975	1,255,803	1,335,935	1,274,637	1,239,140

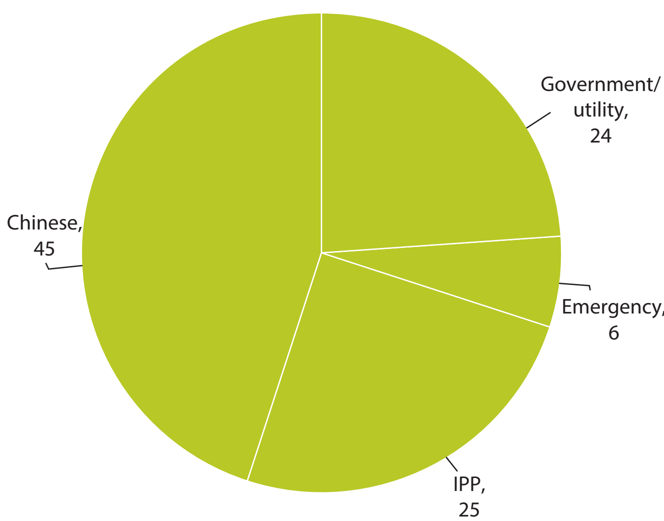
Source: Compiled by the authors, based on various primary and secondary source data.
Note: In the table, "emergency" indicates thermal plant capacity that is now mostly used for backup power on the grid. It is not a short-term rental plant. The steep drop from 2012 to 2013 reflects the entry into commercial service of the Bujagali hydroelectric IPP, which reduced the need for emergency supplies from thermal plants. IPP = independent power project; UETCL = Uganda Electricity Transmission Company Ltd.

Figure 10.8 Ownership and Funding, by Share of Installed Capacity: Uganda, 2014
percent



Source: Compiled by the authors, based on various primary and secondary source data.
Note: IPP = independent power project.

Figure 10.9 Sources of Funding, by Estimated Share of Installed Capacity: Uganda, 2020
percent



Source: Compiled by the authors, based on various primary and secondary source data.
Note: IPP = independent power project.

Costs of Generation

Generation costs in Uganda are not uniformly or universally transparent, even apart from variable components such as the cost of the HFO and diesel fuel used in thermal plants. All large hydropower assets have capacity payment arrangements with the UETCL linked to annual operational targets. The Nalubaale and Kiira projects are fully depreciated, and the unit costs presented in table 10.5 result from the provisions in the concession agreement, pursuant to which Eskom Uganda Ltd. receives a 12 percent return on capital expenditures and an O&M charge, plus its concession fee. For the Bujagali HPP, the agreements are more complex. According to ERA, the final tariff arrangement between BEL Ltd. and the UETCL depends on a final cost audit for the project, which was not yet complete in early 2015.

For existing small-scale IPPs, unit costs are higher than for the large hydropower projects but still much lower than those of thermal plants. Their numbers would appear viable even under the current REFiT regime. However, some factors are not incorporated in the tariffs, as agreed in the PPAs, and need to be incorporated into the real cost of the projects. First, ERA and the UETCL had to agree to extended PPA durations for the Buseruka (40 years) and Bugoye (25 years) SHPs, with high up-front tariffs. The latter project also received substantial grant support through Norwegian development cooperation institutions, which brought the tariff for this $65.7 million project down to the levels presented here. It must further be assumed that some of these sites (Mpanga, Ishasha) represented "low-hanging fruit" among the SHP portfolio in Uganda and hence could be realized at a very competitive cost.

It is difficult to compare hydroelectric costs as they are highly dependent on hydrological and geological site conditions.

The emergency thermal plants are the highest-cost producers. They are being run less and less often, however, as other, more competitive, generation assets are exploited.

Table 10.5 Electricity Costs for All Operational Generation Assets, Uganda

Asset owner/ operator	*Type*	*Form of ownership*	*Specific investment cost (US$/ kW)*	*Levelized cost[a] (USc/ kWh, 2013)*	*PPA duration (years), project finance structure*	*Comment*
Nalubaale GoU/Eskom Uganda	HPP	GoU concession	n.a.	1.2	n.a.	Guaranteed return on CAPEX concession fee O&M costs Capacity availability payment
Kiira GoU/Eskom Uganda	HPP	GoU concession	n.a.	1.2	n.a.	Guaranteed return on CAPEX concession fee O&M costs Capacity availability payment

table continues next page

Table 10.5 Electricity Costs for All Operational Generation Assets, Uganda *(continued)*

Asset owner/ operator	*Type*	*Form of ownership*	*Specific investment cost (US$/ kW)*	*Levelized cost[a] (USc/ kWh, 2013)*	*PPA duration (years), project finance structure*	*Comment*
Bujagali	HPP	IPP	3,444	11.0	30 BOOT	Capacity payment Stepped tariff
Namanve Jacobsen	Emergency thermal	IPP	1,240	24.1	5.5 (extended) BOOT	Fixed cost/capacity charge plus fuel costs
Electro-Maxx	Emergency thermal	IPP	980	27.1	20 BOO	Fixed cost/capacity charge plus fuel costs
Mpanga SAEMS	SHP	IPP	1,517	9.0	20 BOO	Stepped tariff Levelized tariff over PPA: USc 7.732
Buseruka Hydromax	SHP	IPP	4,244	13.5	40 BOO	Three-tier tariff (peak, off-peak, shoulder) Stepped tariff (16 years/24 years) Levelized tariff over PPA: USc 8.3
Bugoye TrønderEnergi	SHP	IPP	5,054	12.9	25 BOO	Stepped tariff Levelized tariff over PPA: USc 8.14
Ishasha	SHP	IPP	2,298	8.3	20 BOO	Three-tier tariff (peak, off-peak, shoulder) Stepped tariff Weighted and levelized tariff over PPA: USc 8.3
Mubuku I	SHP	IPP	n.a.	3.0	2 BOO	Privatized government asset
Mubuku III	SHP	IPP	2,143	5.38	20 BOO	Privatized government asset
Kakira Sugar	Bagasse	IPP	n.a.	8.83 (weighted average across all PPAs)	20 (each) BOO	3 PPAs PPA1+2 (12 MW) PPA3 (20 MW)
Kinyara Sugar	Bagasse	IPP	930	8.1	20 BOO	

Source: Compiled by the authors, based on various primary and secondary source data.
Note: The average 2013 rate of exchange of the Uganda shilling to the U.S. dollar was taken from www.oanda.com ($1 = U Sh 0.0004), accessed February 1, 2015. BOO = build-own-operate; BOOT = build-own-operate-transfer; CAPEX = capital expenditure; GoU = Government of Uganda; HPP = hydropower plant; IPP = independent power project; kW = kilowatt; kWh = kilowatt-hour; MW = megawatt; O&M = operations and maintenance; PPA = power purchase agreement; SAEMS = South Asia Energy Management Systems; SHP = small hydropower plant; USc = U.S. cent; n.a. = not applicable.
a. Projects have been granted varying percentages of indexing for inflation on O&M costs, which has changed the effective tariffs since the conclusion of the PPAs, according to data from the Electricity Regulatory Authority (ERA) website (http://www.era.co.ug, accessed February 1, 2015).

Public Projects

Nalubaale (Owen Falls) HPP/Kiira HPP

Both of the large hydropower projects of the Jinja-Nile hydropower complex, Nalubaale (formerly Owen Falls) and Kiira, are located roughly 2 kilometers (km) downstream from the source of the Nile as it exits Lake Victoria.[18] The projects have an installed capacity of 180 MW and 200 MW, respectively. However, the cumulative average power supply from the entire complex is no more than about 140 MW (peak 220 MW).[19] The low effective power generation capacity results from two factors. First, the hydrology of Lake Victoria, which is 80 percent dependent on regional rainfall, has shrunk markedly since the drought of 2006. Second, the treaty between Egypt and Uganda that regulates the permissible outflow of Lake Victoria—and hence possible power generation—has come increasingly under challenge.[20]

The Owen Falls HPP was built under British colonial rule and commissioned in 1954, initially with a capacity of 150 MW. The project was then owned and operated by the UEB, established in the same decade. In subsequent years, the plant's performance deteriorated until, after the Idi Amin regime, its capacity dropped to 50 MW. In the 1990s, the project was rehabilitated and expanded to its current installed capacity of 180 MW, with World Bank support.

The Kiira HPP was fully commissioned in 2004. The project, which is considered an expansion of the Nalubaale HPP, was initiated by the government in 1993 with financial support from the World Bank and the Swedish International Development Cooperation Agency (Sida), but its first stage was not completed until 2003. As previously noted, both are now operated under the Eskom concession.

Public Projects in the Pipeline

At the time of this report, the government was in the process of finalizing the financing for the Muzizi HPP, a 46 MW hydropower project in the Lake Albert region. This initially PPP-earmarked project is being implemented by the UEGCL, which will procure an EPC contractor through an international competitive bid (ICB). KfW, along with the French Agence Française de Développement (AfD), intend to provide concessional loans for this project, which is expected to reach financial close in 2016.

The Nyagak III SHP, a 5 MW project located in the West Nile Rural Electrification Company (WENRECO) isolated grid in the West Nile region, was also in the later stages of project preparation at the end of 2014. This PPP project, the first of its kind in Uganda, will be implemented through a special-purpose vehicle (SPV), in which the private developer will be co-shareholder with the UEGCL. KfW also supports this project. Financial close is expected in 2016.

Independent Power Projects

Uganda's experience in IPP development is among the most interesting in Africa. By 2012, it had implemented 11 IPP projects across a diverse set of generation technologies and project capacities. Between 2015 and 2018 it is expected that up to 20 small-scale (1–20 MW) projects will be added to this portfolio through the government's cooperation with KfW on the GETFiT Uganda program.[21]

A Short History of IPPs in Uganda, 1950–2012

Mubuku I SHP (5 MW) was commissioned in the 1950s to provide electricity for the copper ore extraction ventures of Kilembe Mines Ltd. Since these core operations stalled in the 1970s, the company has been selling electricity to the Ugandan grid.

Kakira Sugar Ltd. (52 MW/32 MW available to grid) is East Africa's biggest sugar producer. After effective expropriation through Idi Amin's forced exodus of Indians in 1972, the owners began rebuilding the sugar production facilities in 1985 with support from IDA and the African Development Bank (AfDB). Since 2003, the cogeneration facilities of the sugar plant in Jinja have been feeding noncaptive electricity into the Uganda grid. From initially only marginal excess power, the available capacity increased to 32 MW by 2014. The latest expansion (to 30 MW total capacity, with 20 MW to grid in 2012/13) went hand in hand with an expansion of sugar production facilities. The expansion was realized with financing from local commercial banks and the East African Development Bank (EADB).

Mubuku III SHP (10.5 MW) is a hydropower plant linked to the extraction operations of the Kasese Cobalt Company Ltd., which uses most of the electricity generated. The IPP project was commissioned in 1998 and realized at a cost of $22.5 million. In the first decade of its operation, nearly all of the plant's generation was for captive use.

Namanve Thermal (50 MW), one of the two remaining thermal power plants in the country, is operated by Jacobsen of Norway. Currently, the plant is on cold standby for emergency backup. The company won the build-operate-transfer (BOT) deal after a much-disputed ICB process. The total investment cost of $62 million was financed through one Ugandan and one Norwegian commercial bank, and supported by the Norwegian Agency for Development Cooperation (NORAD). Until the expiry of the PPA in March 2015, Jacobsen was paid a capacity charge by the UETCL, although effectively payments come directly from the government. The future ownership and operation of this project is under discussion. The most likely scenarios are that the PPA with Jacobsen is extended until 2021 or that ownership is transferred to the UEGCL on the basis of a build-own-operate-transfer (BOOT) arrangement. The second option would require that the government repay, in full, the outstanding debt to the Norwegian financiers.

Kinyara Sugar Cogen (14.5 MW/4.5 MW available to grid) is the second power plant based on bagasse cogeneration technology currently operative in Uganda. The cogeneration facilities were installed in 2009 at an estimated investment cost of $13.2 million. In 2014, Kinyara Sugar Works Ltd. was in the final stages of planning an expansion of the power plant, which will increase its installed capacity to 44 MW (24 MW available to grid).

Bugoye SHP (13 MW), located on the Mubuku River, is currently operated by TrønderEnergi of Norway. A financing consortium consisting, on the equity side, of TrønderEnergi and Norfund, and of the Emerging Africa Infrastructure Fund (EAIF) on the debt side, raised the total investment costs of $65.7 million, with some grant support from the government of Norway. The plant began commercial operation in 2011. The project was implemented through an EPC contract (Noremco, ABB, Mavel).

Tororo Thermal (50 MW) is often considered the first indigenous African IPP; it is financed, built, and operated solely by Africans. The HFO-based thermal plant was implemented in two stages. In 2009, the first 20 MW came online, while the additional 30 MW were commissioned in 2012. The project cost of $49 million was funded by local investors and commercial banks and was considerably cheaper than the Jacobsen plant.

Mpanga SHP (18 MW) was commissioned in 2011. The project was developed and is operated by the South Asia Energy Management Systems (SAEMS), a U.S.-based renewable power developer. The $27.5 million project was financed through a multiproject international facility of $110 million, of which the EAIF, the Netherlands Development Finance Company (FMO), and the German Investment and Development Corporation (DEG), financed $72 million. VS Hydro of Sri Lanka was the EPC contractor for the project.

Ishasha SHP (6.4 MW) is the first power plant of an expected series of projects developed by Sri Lankan developers. Eco Power Ltd. realized the build-own-operate (BOO) project in the remote west of the country at a cost of $14.71 million, of which the 65 percent debt portion was financed by Sri Lankan commercial banks. The construction process was partially implemented and entirely supervised by Eco Power Ltd. under a split contract.

Buseruka SHP (9 MW) was developed by Hydromax (Uganda) Ltd., a domestic hydropower developer backed by the Uganda civil contractor Dott Services Ltd. The project was commissioned in 2012 and realized at a total cost of $38.2 million, for which African Preferential Trade Area Bank (PTA) and AfDB provided the debt financing. This project, too, was carried out under a split contract, with Dott Services Ltd. being responsible for the civil works and Tata Consulting Engineers for design and engineering.

As indicated, with an estimated total investment volume of $860 million, the *Bujagali HPP (250 MW)* still ranks among the largest privately financed hydroelectric power projects in Sub-Saharan Africa. From the government's side, the project was supported by ODA (which took the form of equity contributions) and by a sovereign guarantee of payments by the off-taker. The security package offered to the developer and lenders also included significant contributions by the WBG, which provided a partial risk guarantee (PRG) for the debt tranche and a $115 million equity investment guarantee from the MIGA. Further project financing and operational details are provided in table 10.6.

The GETFiT Project Portfolio

One of the key measures in the 2007 Renewable Energy Policy was the introduction, through ERA, of a REFiT scheme. To avoid impacts on end-user tariffs, REFiTs were purposefully kept low and did not cover the levelized cost of

Table 10.6 Overview of Bujagali HPP—Implementation, Financing, and Cost: Uganda

Date of entry into commercial operation	2012
Financial close	2007
Contract type	BOOT
Shareholder equity	$151 million
Amount supplied by development finance institutions (and participating institutions)	$512 million (IFC, EIB, Proparco, KfW, AfDB, FMO, DEG, AFD)
Commercial lending (and participating banks)	$115 million (Standard Chartered, Absa)
Engineering, procurement, and construction	Salini
Equipment supplier	Alstom/Sinohydro
Capacity charge (levelized average over lifetime of PPA)	USc/kWh 0.987
Sales to the grid (MWh, 2013)	1,375.57

Source: Compiled by the authors, based on various primary and secondary source data.
Note: Absa = South African commercial bank; AFD = Agence Française de Développement; AfDB = African Development Bank; BOOT = build-own-operate-transfer; DEG = German Investment and Development Corporation; EIB = European Investment Bank; FMO = Netherlands Development Finance Company; HPP = hydropower plant; IFC = International Finance Corporation; KfW = Kreditanstalt für Wiederaufbau; kWh = kilowatt-hour; MWh = megawatt-hour; PPA = power purchase agreement; USc = U.S. cent.

electricity for the renewable energy technologies included. Also ERA was not successful in obtaining international funding subsidies or carbon credit facilities for renewable energy. The IPP projects implemented between 2007 and 2012 were either financed against the balance sheets of sugar factories or came at higher prices than the REFiTs, both in terms of effective tariff charges[22] and transaction costs. A key positive outcome of this phase, however, was that the basic regulatory framework started to be operationalized and capacitated.

The 2007 REFiT levels were revised by ERA in 2011, but the proposed tariffs still did not cover the levelized cost of electricity over all RETs. KfW then helped ERA to develop the GETFiT approach to incentivize new investments to plug the gap between supply and demand until the two new large hydropower projects, Isimba and Karuma (described in the next section), came online.

The primary GETFiT mechanism is a grant-based premium payment over the REFiT levels to close the gap with the levelized cost of energy for eligible technologies—namely, small hydropower, biomass, bagasse, and solar PV. The per-kWh-based GETFiT subsidy is calculated over the 20-year lifetime of the PPA but works as a performance-based payment over the first five years of operation to enhance the project's debt-service profile.

An important and valuable part of the program was the development of a full set of legal documents—among them standardized (and investor-approved) PPAs, implementation agreements (IAs), and direct agreements (DAs) (securing lender takeover rights).

In addition, World Bank PRGs are available to successful projects to address off-taker and termination risks. This was an innovative offering in the sense that the Bank offered in-principle approval for a portfolio of projects, thus potentially reducing the transaction costs for individual projects. The PRGs are designed to backstop government support for letters of credit (LCs) issued by commercial banks against defaults by the utility. The letters can be drawn by a developer in the event of an interruption in PPA payments by the UETCL, and the PRG guarantees the issuing bank's debt, thus offering certainty about liquidity to lenders and project developers. Once an LC is drawn, the national government is obligated to repay the amount drawn (with interest) to the issuing bank within a certain period. The repayment period allows time for the resolution of the issues that led to the default and for the World Bank to intervene if necessary. If the issuing bank is not reimbursed during this period, then it may call in the PRG. At the time of writing, no GETFiT project had used this facility. This may change as projects that rely more on commercial debt rather than on funding from other development finance institutions approach financial close.

GETFiT also supports lender due diligence and has assisted the government of Uganda in streamlining procedures essential for IPP project implementation, such as the permit and licensing process as well as the operationalization of tax and custom exemptions provided for IPP projects in Uganda.

Three competitive tenders were run between 2013 and 2015 for small hydropower and biomass (1–20 MW) based on quality, rather than the price of projects. Projects had to meet minimum qualitative benchmarks (table 10.7). Prices were determined by the REFiT plus the premium payment. Project developers had to propose their own sites, conduct full feasibility and interconnection studies, and secure ERA permits and environmental and social impact assessments in compliance with the performance standards of the IFC, including, where

Table 10.7 GETFiT Evaluation Criteria, Uganda

Classic GETFiT (small hydro, biomass, bagasse)	*GETFiT solar facility*
Financial and economic performance	Economic performance
Minimum financial internal rate of return, debt-service cover ratio, sensitivity	Economic rate of return
Dynamic production cost, economic rate of return, contribution to energy balance and grid stability	Project maturity and location
Environmental and social performance	Environmental and social performance
Quality and compliance with IFC rules on environmental and social impact assessment and environmental and social action plan	
Quality and compliance with IFC rules on Resettlement Action Plan and livelihood restoration framework	
Technical and organizational performance	Technical and organizational performance
Feasibility of proposed site	Quality of technical documentation
Quality of technical documentation	Project implementation timeline/expected commissioning date
Project implementation timeline	Price proposed per kilowatt-hour (70 percent of total score)
Maturity of project and financial package	
Risk analysis	

Source: Compiled by the authors, based on various primary and secondary source data.
Note: GETFiT = global energy transfer feed-in tariff; IFC = International Finance Corporation.

applicable, a Resettlement Action Plan. An additional competitive tender was run in 2014 for solar PV projects with a maximum size of 5 MW.

GETFiT also funded a secretariat supported by an implementation consultant. The secretariat ran the tenders and assessed bids with ultimate approval from an investment committee. By early 2015, GETFiT had confirmed support for a total of 15 projects with an accumulated capacity of 128 MW (table 10.8). Forty-one applications were received over three bid rounds.[23] In January 2015, the third and last request for proposals (RfP) under the original GETFiT setup was launched. At the final GETFiT Investment Committee meeting in June 2015 a further six projects were approved although, because of funding constraints, just three small hydropower projects totaling 25 MW were to be set up: Nyamagasani I and II and Ndugutu.

For the solar PV tenders, 24 candidates submitted expressions of interest, out of which 9 were short-listed and 7 submitted bids. Two developers were awarded two 5 MW projects each at a tariff of $0.164/kWh, substantially lower than the directly negotiated deals in Rwanda and Nigeria, which are above $0.25/kWh. Nevertheless, the Ugandan GETFiT PV prices are disappointing; they are twice the levels obtained in South Africa's Renewable Energy Independent Power Project Procurement Programme (REIPPPP). Granted, the investment context in Uganda is very different from that of South Africa in terms of scale and risk, but the premium still seems high. Hopefully greater competition in subsequent rounds will drive prices lower.

GETFiT was designed as a temporary facility and will likely be phased out. The idea was to stimulate the small-scale renewable energy market, initially through a premium payment but also by firming up the contractual framework and providing confidence to investors. It remains to be seen whether further regular competitive tenders will be conducted by ERA after the withdrawal of donor support.

Chinese-Funded Projects

In February 2015, financing conditions for two large Chinese-funded projects had been approved by the Ugandan parliament.[24] According to the PSIP, the third major hydropower scheme, Ayago (also 600 MW), is scheduled for launch in 2018.

The bidding and award processes used for the Karuma and Isimba HPPs have taken various turns over the past two decades. The government's plans for Karuma were revised many times before a decision was made sometime in 2009/10 to implement it as a public project. Initially listed as a PPP, Karuma had been under development by Norway's Norpak Power Ltd. since the late 1990s, based on a 250 MW design. Norpak lost its exclusivity in 2008 after it failed to raise sufficient funds to advance the project beyond the feasibility stage.[25] After the government decided to increase Karuma's planned capacity to 600 MW and procure a new feasibility study, support from Western donors waned over concerns about the environmental impact of the project, which lies on the boundary of one of Uganda's most pristine national parks. One additional comment frequently made by stakeholders has been the considerably larger "ticket size" (financing packages) offered by Chinese and other non-Western financiers,

Table 10.8 Overview of Approved GETFiT Projects, Uganda

Name	*Capacity (MW)*[a]	*RET*	*Developer/promoter*	*Total investment cost (US$, millions)*	*REFiT (USc/kWh)*	*GETFiT top-up (USc/kWh)*	*Equity/debt origin*
Nyamwamba	9.2	SHP	SAEMS	26.8	8.5	1.4	SAEMS/FMO
Rwimi	5.5	SHP	Eco Power	20.8	9.8	1.4	Eco Power/BIO
PH Industrial Biomass	1	Biomass gasification	PH Industrial Farms	3.5	10.3	1	Shareholder/domestic commercial
SAIL Cogen	11.9 (6.9)	Bagasse cogeneration	Sugar Allied Industries Ltd.	21.6	9.5	0.5	Shareholder/domestic commercial
Kikagati	16	SHP	TrønderEnergi	64.4	8.5	1.4	Norfund/EAIF
Kakira Cogen extension	32 (20)	Bagasse cogeneration	Kakira Sugar Ltd.	60.7	9.5	0.5	Shareholder/domestic commercial
Nengo Bridge	6.7	SHP	Jacobsen	30	9.4	1.4	Jacobsen/EADB
Muvumbe	6.5	SHP	Vidullanka	14.1	9.4	1.4	Muvumbe/international commercial
Lubilia	5.4	SHP	DI Frontier	18.7	9.9	1.4	DI Frontier/FMO
Siti I	6.1	SHP	DI Frontier	14.8	9.6	1.4	DI Frontier/FMO
Siti II	16.5	SHP	DI Frontier	34	8.5	1.4	DI Frontier/FMO
Sindila	5.2	SHP	KMR Infrastructure	17.1	9.9	1.4	KMRI/OPIC
Waki	4.8	SHP	Hydromax Ltd.	18.11	10.1	1.4	Shareholder/PTA
Tororo North/South	10	Solar	Simba/Building Energy	18	11	5.3[b]	Shareholder/shareholder
Soroti I/II	10	Solar	Access/TSK	18	11	5.3[b]	Access/FMO

Source: Compiled by the authors, based on various primary and secondary source data.
Note: EADB = East African Development Bank; EAIF = Emerging Africa Infrastructure Fund; FMO = Netherlands Development Finance Company; GETFiT = global energy transfer feed-in tariff; kWh = kilowatt-hour; MW = megawatt; OPIC = Overseas Private Investment Corporation; PTA = Preferential Trade Area Bank; REFiT = renewable energy feed-in tariff; RET = renewable energy technology; SAEMS = South Asia Energy Management Systems; SHP = small hydropower plant; USc = U.S. cent.
a. For plants with captive use (bagasse), only the generation capacity available to the grid will be supported through GETFiT premiums.
b. Average top-up.

which exceed the maximum loan amounts available from international financial institutions. The tedious coordination efforts and transaction costs occasioned by the multitude of financiers involved in the Bujagali HPP project apparently had left a lasting impression on Ugandan government officials.

Once the new consultant submitted the revised studies for Karuma, the MEMD implemented a new procurement process on the basis of a public EPC model, including project financing.[26] The MEMD, following the provisions of the Public Procurement and Disposal of Public Assets (PPDA) Act, established evaluation and contract committees, both staffed solely with senior officials from the MEMD and other sector institutions. Although the PPDA Act generally offers comprehensive guidelines for conducting public procurement, the highly politicized process soon ran aground after allegations of bribery and violation of the guidelines surfaced.[27] As a result, in September 2012 the PPDA Authority, and subsequently the Inspectorate General of Government (IGG), called, in March 2013, for a halt to the process, called for a review, and opened investigations. Its report identified various violations of procurement regulations.[28] Although Uganda's High Court confirmed a violation of procurement guidelines assessed by the PPDA Authority in November 2012,[29] the tender process continued after a short interruption with a reevaluation of the technical bids. CWE of China again emerged as the best-qualified bidder. However, the procurement process had lost all public credibility and was effectively suspended.

Confronted with the impasse, President Yoweri Museveni utilized the occasion of the 2013 Durban, South Africa, BRICS[30] conference and a meeting with Chinese president Xi Jinping to award the Karuma HPP to Sinohydro and the Isimba HPP to CWE. For both projects, the China ExIm Bank committed, in principle, the required debt financing.

Awarding the Isimba HPP at this point in time surprised many donors and DFIs. However, the prospect of receiving an attractive financing deal for both projects from the China ExIm Bank swayed the government.[31] As appealing as the deal may have been, its acceptance may have not been in compliance with Ugandan law, in particular with the PPDA Act.[32]

In early 2014, the final financing conditions for both projects were presented to the Ugandan parliament, which approved the $1.4 billion loan agreement for Karuma in March 2015. The deal specified that the government would provide a 15 percent advance equity investment (amounting to $253 million for Karuma), which the contractors used to kick off preliminary works. Funds came from the dedicated reserves that the government had earmarked and accumulated since 2007.

Loan repayments will be made through electricity payments under a still-to-be-concluded PPA with UETCL. Payments will be backed by the government through separate guarantee agreements, as for the Bujagali HPP. At the time of this writing, details of the contractual arrangements were still under discussion. However, the Ugandan government and ExIm Bank of China have agreed on a capacity payment basis for both projects. Effective tariff levels for Isimba and Karuma were not presented to the public.

Karuma HHP

The ExIm Bank of China is providing financing for the Karuma HPP in the amount of $1.437 billion (85 percent of the total funding required)—see table 10.9).

Forty-five percent of the loan amount will take the form of an export buyers' credit (a commercial loan) at an annual interest rate equal to the LIBOR[33] plus 3.5 percent, with a repayment period of 15 years and a five-year grace period. The lender will assess a one-time management fee of 0.75 percent and a commitment fee of 0.5 percent of the loan amount. The terms include the cost of loan insurance.

Fifty-five percent of the loan amount will be in the form of a "preferential export-based credit." The repayment period is 20 years, with a 5-year grace period. The interest rate is 2 percent per year. The lender will assess a one-time management fee of 1 percent and a commitment fee of 0.75 percent.

Isimba HHP

The ExIm Bank of China, through its preferential export buyers' credit window, is providing financing for the Isimba HPP in the amount of $482.2 million (85 percent of the total funding required) at an annual interest rate of 2 percent over a period of 20 years, with a 5-year grace period (table 10.10).

Table 10.9 Karuma HPP Project Data, Uganda

Installed capacity	600 MW
Estimated total cost	$1.6 billion, including interconnection
Estimated cost per megawatt	$2.34 million[a]
Engineering, procurement, and construction	Sinohydro
Commitment of Ugandan government	15 percent of total costs; guarantee agreement
Funding source	ExIm Bank of China
Expected date of entry into commercial operation	2019

Source: Compiled by the authors, based on various primary and secondary source data.
Note: HPP = hydropower plant; MW = megawatt.
a. This figure assumes construction costs of $1,400 million for the Karuma HPP, and $200 million to build the required high-voltage grid infrastructure.

Table 10.10 Isimba HPP Project Data, Uganda

Installed capacity	183 MW
Estimated total cost	$570 million, including interconnection
Estimated cost per megawatt	$3 million[a]
Engineering, procurement, and construction	CWE (subcontracting to Sinohydro)
Commitment of Ugandan government	15 percent of total costs; guarantee agreement
Funding source (and amount)	ExIm Bank of China ($482.2 million)
Expected date of entry into commercial operation	2018

Source: Compiled by the authors, based on various primary and secondary source data.
Note: HPP = hydropower plant; MW = megawatt.
a. This figure assumes construction costs of $550 million for Isimba HPP. In comparison with the Karuma HPP, this project will require significantly less expenditure for power evacuation owing to its proximity to the Bujagali HPP.

The lender is charging a one-time management fee of 1 percent of the loan amount and a commitment fee of 0.75 percent. Concerns remain about the project's compliance with applicable international environmental and social safeguards.

Ayago HHP

Ayago HPP, another major Nile-based hydropower project, located in the vicinity of Murchison Falls National Park, had long been promoted by Japanese developers—the Electric Power Development Company Ltd. (J-Power) and Nippon Koei Co. Ltd.—supported by the Japan International Cooperation Agency (JICA). After a prefeasibility study was submitted to the MEMD, the Ugandan government, in April 2013, signed a memorandum of understanding (MoU) with the Mapa Construction Company, a Turkish infrastructure conglomerate. Subsequently, Japanese support for the project ceased.[34] After negotiations with the Turkish developer reached an impasse (owing to a $1.9 billion price tag and the denial of a sovereign guarantee), this developer, too, abandoned the project.

In late 2013, the Ugandan government awarded the EPC contract for Ayago HPP to China Gezhouba Group for a price of $1.6 billion (table 10.11).

In early 2015, financing arrangements for the project were still under discussion with the ExIm Bank of China. Compared with the swift conclusion of the financing arrangements for the Karuma and Isimba HPPs, progress on Ayago has been slow. This may be due to the government's initial plan to implement the three major hydropower projects in staged phases. Others have pointed to the large risk exposure of the ExIm Bank of China to the Ugandan energy sector. Alternatively, given the current dip in demand growth, some doubts may have emerged about whether demand would be sufficient for the 1,000 MW under implementation. If that is true, projects situated in environmentally sensitive areas may be delayed. Finally, Uganda has not yet fully incorporated opportunities for energy imports through the Eastern Africa Power Pool (EAPP) into sector planning and practice. Once relevant infrastructure is built between Ethiopia, Kenya, and Uganda, imported electricity may become a cost-competitive solution.

Table 10.11 Ayago HPP Project Data, Uganda

Installed capacity	600 MW
Estimated total cost	$1.6 billion, including interconnection
Estimated cost per megawatt	$2.67 million
Engineering and construction	China Gezhouba Group
Commitment of Ugandan government	To be confirmed
Funding source	ExIm Bank of China
Expected date of entry into commercial operation	To be confirmed

Source: Compiled by the authors, based on various primary and secondary source data.
Note: HPP = hydropower plant; MW = megawatt.

Measuring the Outcomes

This section compares the results obtained from international competitive bidding, directly negotiated projects, FiTs, and the recent Chinese-funded projects.

In general, it can be said that the government has been successful in achieving its development goals for the power generation sector. With close to 1,000 MW under implementation or in later feasibility stages, capacity under development has multiplied within a short time frame of three years. Uganda has also managed to develop a mix of public projects financed by Chinese sources and privately financed small-scale IPP projects, a mix that is unique in Sub-Saharan Africa.

The late 2000s were shaped by the need to attract international investment to replace costly diesel-based generation and to avert the financial demise of the energy sector. The facilitation of small-scale RET projects and the implementation of the GETFiT program were based on a desire to mitigate the interim supply shortages expected to emerge in 2015. Since the commissioning of the Bujagali HPP in 2012, pressures on the Ugandan government have eased noticeably—albeit only on the supply side, not the consumer tariff side. Since then, the sector strategy seems to have consolidated, and more forward-looking policies are reflected in decision making.

Procurement Approaches: A Shift in Policy

The Ugandan government intends to follow a two-pronged policy for procuring generation capacity in the years to come. For large-scale projects, international competitive bidding seems to have been abandoned in favor of direct awards to international—effectively Chinese—contractors. On the other end of the scale, targeted policies (promoted in particular by ERA) aim to further encourage foreign investment in IPP projects involving all types of generation from small to medium scale.[35]

The government has utilized the full spectrum of procurement approaches over the past 15 years (table 10.12). With the current uptake in small-scale RET development facilitated by the GETFiT support mechanism, up to 15 REFiT and

Table 10.12 Summary of Procurement Models Used since the Sector Reform of 1999/2000, Uganda

International competitive bidding	*Direct award*	*Unsolicited bids*
Lugogo (emergency diesel)	Kiira (HPP)	Kakira Sugar (bagasse)[a]
Namanve (emergency HFO)	Kiira (emergency diesel)	Kinyara Sugar (bagasse)[b]
Bujagali (HPP)	Mutundwe (emergency diesel)	Bugoye (SHP)[b]
	Karuma (HPP)	Tororo (emergency HFO)[b]
	Isimba (HPP)	Mpanga (SHP)[b]
		Ishasha (SHP)[b]
		Buseruka (SHP)[b]

Source: Compiled by the authors, based on various primary and secondary source data.
Note: HFO = heavy fuel oil; HPP = hydropower plant; SHP = small hydropower plant.
a. The first and second power purchase agreements were individually negotiated, and the third occurred under the renewable energy feed-in tariff (REFiT), with global energy transfer feed-in tariff (GETFiT) support.
b. Individually negotiated tariff.

2 competitively bid projects will complete the picture. Some aspects of the country's procurement methods, in particular the abandonment of international competitive bidding in favor of direct awards for large hydropower, merit further analysis and consideration.

The Case for the Direct Award of the Karuma and Isimba Projects

Whereas the ICB process is regulated by legislation, in particular the PPDA Act, the direct award of contracts such as utility-scale hydropower projects has no specific legal foundation. The Ugandan government has therefore achieved its objective of setting up large projects of critical importance to the security of the nation's energy supply. Only six months passed between the awards and the first steps by the EPC contractors toward final design studies. Another six months later, after the provision of a substantial advance payment by the government, the projects are in early stages of construction.

For the time being, ICB and IPP are perceived by the government of Uganda as too costly and time consuming for large-scale projects. Public and government perceptions have been shaped—understandably, but nevertheless erroneously—by unfavorable comparisons of the government-owned Nalubaale and Kiira with the privately sponsored Bujagali HPP, in particular, with regard to cost and implementation timelines.

The Argument for Lower Costs

Whereas these projects sell electricity to the UETCL at an estimated $0.012, Bujagali-generated electricity is bought at roughly USc 10 more. There is little appreciation that the costs of Nalubaale and Kiira are fully amortized or that the tariffs approximate short-run, rather than long-run marginal costs. For the Karuma and Isimba HPPs, the government publicly communicates an expected tariff range of USc 4–6/kWh. Representatives of development partners, as well as the private sector, have questioned these numbers, and a closer look at current cost estimates and the financing conditions under discussion do not immediately bear out the government's expectations.

At $3.44 million/MW, the Bujagali HPP certainly ranks among the more expensive projects of its scale in the world (IRENA 2012). Karuma's likely cost is estimated at $2.33 million/MW, whereas Isimba's, at $3 million/MW, is close to Bujagali's. The government argues that final costs for public projects will be lower owing to lower transaction costs between lenders and, as government officials have recently maintained, the "hidden cost" or "financing premium" of private investment—the suggestion being that private investors seek a higher return than the currently favored alternatives.

Overall, it is too early to support or reject the government's stance, and it remains to be seen whether actual costs match the projections. Neither Karuma nor Isimba has reached formal financial close, which indicates that the government's equity contribution or some other aspect of the financing arrangements may still be altered to the disadvantage of the Ugandan government and consumers. Furthermore, frequent cost overruns for large hydropower projects mean that the attractiveness of these projects is more likely to diminish than to improve. Ultimately what counts is the contracted tariff, which still has to be revealed. The government's cost argument for pursuing direct awards may turn out to be built on sand. Meanwhile, the lack of transparency surrounding the award and the related negotiation process create the risk that the final total costs of the two projects may be inflated by illicit money flows.

The ICB/IPP approach was arguably more beneficial for the national budget, at least in the short term. For the Chinese-promoted projects, the government had to make an advance payment of roughly $320 million (equivalent to 15 percent of estimated total project costs); its equity contribution for the Bujagali HPP was only $20 million (or 2.3 percent of the total cost). Although dedicated reserves for this investment had been accumulated over the past years, this significant capital expenditure is no longer available for other strategic investments in the energy sector.

The Argument for Shorter Implementation Timelines

The other main argument presented for direct awards is their comparatively shorter implementation timelines. The full procurement cycle for the Bujagali HPP is said to have taken more than 12 years. In contrast, the implementation of the similar-sized Kiira HPP in the early 2000s is recorded—inaccurately—as having proceeded without complication or delay.

If the Karuma and Isimba projects took six years from award to expected commission, a transparent international competitive bidding procurement process that conforms to all (international) legalities and formalities cannot compete.[36] Several major factors cause delay in ICBs:

- An ICB process can effectively encompass up to three consecutive procurements: (1) developer/investor, (2) EPC, and (3) O&M provider.
- An ICB is more sensitive and prone to interference by external actors. As illustrated by the first Karuma procurement attempt, in an imperfect procurement environment and absent clear judicial procedures and remedies, this can easily lead to an impasse in procurement and thus to delays
- The time required for coordination among a multitude of commercial and development finance institutions, along with associated transaction costs, has been named as a serious disadvantage by Ugandan stakeholders.
- If they apply, international high standards for environmental and social sustainability require substantive baseline studies and implementation schemes that are, in contrast to domestic environmental legislation, time consuming.

With specific reference to the two latter points, officials of the Ugandan government speak frankly about a "lesson learned" from the Bujagali HPP procurement. And, indeed, lengthy and expensive investor arrangements and delays occasioned by protracted environmental studies at a time when Uganda was relying on costly thermal power have justifiably caused lasting grievances among officials. At first glance, therefore, the decision for direct awards would seem to be based on sound facts and judgment, particularly if one takes into account the recent international competitive bidding experience around the Karuma HPP.

It is possible that international competitive bidding per se was not the cause of the failure, but rather the institutional arrangements made for its implementation, especially the exclusion of external experts from the procurement process and decision-making bodies. Furthermore, Ugandan government officials seem to forget that the first failed attempt to implement the Bujagali HPP was the result of a flawed direct-award process, which in the end had to be aborted after illicit money flows and corruption came to light.

At the time of writing, the direct award of the Karuma and Isimba HPPs may result in a gain of about two years in comparison with Bujagali. Present delays in reaching financial close may yet shrink that gain. Construction delays may shrink it further.

The Future of Private Sector Investment and of Thermal and RET Project Development

President Museveni and numerous officials now often publicly discourage private sector involvement in the energy sector.[37] In so doing, they effectively negate the impressive development of the Ugandan private sector in the last decade. With good reason, investors rank Uganda as one of the top destinations worldwide for private sector investment in RET (BNEF 2014). With regard to thermal-based power generation, by contrast, the near-term prospects for the private sector do not seem as bright.

The Legacy of the Sector Crisis

With existing emergency thermal capacity only occasionally dispatched and unreliable government payments for the availability of Namanve and Tororo, there are few incentives for additional international investment into thermal power. The current balance of demand and supply, coupled with lower-than-expected growth in demand, has contributed to a deterioration of the business case for expensive thermal power. With tariffs ranging from \$0.23 to \$0.30/kWh, thermal-based power is not competitive. Moreover, in the wake of the sector crises of the late 2000s, the government, jointly with development cooperation partners, has taken steps to avoid the need for installation of additional thermal-based power plants. With an estimated additional generation capacity of 170 MW facilitated through the GETFiT program, which will come on-grid between 2015 and 2018, the likelihood of dispatch of (additional) thermal power has been brought close to zero.

Nevertheless, future market opportunities for thermal power could arise as a consequence of petroleum exploitation in Uganda. Once commercial operations have started, residual gas or, if the envisaged refinery is built, residual heavy fuel could generate a business case for promoters of thermal power plants. Yet recent media reports suggest that the commencement of oil exploitation may well be postponed beyond 2018. The thermal power sector will likely remain dormant for some years to come.

In the past, the government has utilized a range of procurement methodologies, from direct awards to "pure" IPP-promoted, unsolicited bids. The outcomes of these arrangements are inconclusive, as tariffs were heavily influenced by externalities such as fuel prices, fuel sources, and the government's decreasing dependency on thermal power, among other factors. Across the various procurement processes tariff levels declined without any discernible connection to procurement type.

The Rise of Small-Scale RET Projects

Since the first IPP projects were commissioned in the late 2000s, the RET sector has undergone a remarkable evolution. At the time of writing, in addition to the four assets already operational, more than 15 RET projects across various generation types are in their late feasibility stages and approaching financial close and implementation. The reasons for these developments are multifaceted, but some core lessons are clear.

Until 2012, sectoral arrangements and contractual conditions were directly negotiated between ERA, the UETCL, and the MEMD, resulting in high transaction costs and comparably high tariff levels. These projects reflected an energy sector in transition, characterized by grant support through development cooperation, varying tariff arrangements, and divergent provisions in PPAs and governmental guarantees. All tariffs effectively agreed upon by ERA between 2008 and 2012 went significantly beyond the then-applicable REFiT levels introduced in the 2007 Renewable Energy Policy,[38] which, as previously indicated, had purposefully been set low to shield the end-user tariff from price impacts.

Since 2012, the Ugandan government and its entities, notably ERA, have enhanced and complemented the existing policy on private investment in renewable energy by addressing regulatory shortfalls. The government and ERA have understood the need for investment security in the face of high up-front capital expenditures for RET project development and long return timelines. While some of these enhancements can certainly be attributed to the government's cooperation with the GETFiT program, other key requirements for a successful IPP environment were promoted at the government's and ERA's own discretion. The 2012 interconnection policy, which recognized the government's responsibility to provide a grid connection for REFiT projects, is a noteworthy example. Furthermore, the establishment of the joint interconnection task force in 2014 to address the cumulative effects of decentralized generation and the integration of RET projects has further increased investor confidence.

In the facilitation of small-scale RET, ERA has demonstrated regulatory flexibility in the implementation of suitable incentivizing mechanisms. This has been achieved by opening the sector to competitive bidding structures for different RET types in cooperation with the GETFiT program. Two approaches have been taken. First, for small hydropower, biomass, and bagasse, ERA and GETFiT have introduced a hybrid system of REFiT and top-up payments, with a competitive tender procedure. As previously presented, projects are evaluated by an external appraisal team and ranked according to their overall quality, the capacity of the developer, and the level of project preparedness. As an outcome, an external expert team effectively supports ERA in selecting the most promising and advanced projects eligible for the REFiT. Simultaneously, this external expertise has further sparked investor interest in the Ugandan project pipeline and made it significantly easier for investors to attract financing.

The second procurement approach introduced a price-competitive component into the general project selection process, enabling ERA to include solar PV in the power generation mix. This methodology was adopted to reflect the levelized cost of solar PV, which presently is not easily quantified. For the time being, price-competitive bidding has been implemented only for solar PV, but the Electricity Act (1999) generally allows competitive bidding across all technologies. In the future, a similar approach might be used to harness wind or biomass resources.

Other instruments to facilitate project-financed RET projects complemented the incentivizing frameworks. Examples include standardized legal agreements and the mitigation of off-taker risks through a sovereign guarantee and the World Bank PRG program. Most important, however, the Ugandan government and ERA have understood the need for cohesiveness in policy and frameworks, as well as the importance of transparency and reliability. If Uganda firmly pursues its current path, it is well positioned to become a model for RET facilitation in Sub-Saharan Africa.

Notes

1. The following section draws heavily (and with permission) from Kapika and Eberhard (2013).
2. The UEB was not able to finance investments or service debts and was thus financially dependent on government support. Collection rates were as low as 50 percent; loss rates exceeded 30 percent. Less than 5 percent of Uganda's population had access to electricity.
3. The full name of the plan was the Ugandan Power Sector Restructuring and Privatisation: New Strategy Plan and Implementation Plan, Government of Uganda, 1999.
4. Umeme's shareholders were Globeleq (56 percent) and Eskom Enterprises (44 percent).
5. Eskom Enterprises exited at this stage, with Globeleq the sole remaining shareholder.
6. http://uk.reuters.com/article/2012/01/12/uganda-electricity-subsidy-idUKL6E8CC2D120120112, last accessed February 1, 2015.
7. In some regards, the period between 2005 and 2012 also produced positive outcomes: for example, the doubling of electricity connections and available generation capacity, which effectively exceeded the increase seen in the years 1950 until the initialization of the 1998 reforms. Furthermore, the improvements in loss and collection rates generated stable money flows between sector actors and enabled UETCL and Umeme to further rehabilitate and expand electricity infrastructure (USAID 2013).

8. Incentives to invest in new generation capacities could arguably be boosted by increasing end-user tariffs as in 2012. However, the political and sectoral environment is currently not favorable for such measures. In the context of the 2016 elections, government has repeatedly declared that it intends to reduce end-user tariffs particularly for industrial consumers.
9. http://www.getfit-uganda.org/, accessed February 1, 2015.
10. http://global-climatescope.org/en/, accessed February 1, 2015.
11. All inclusive of interest during construction. Interestingly, the Power Sector Investment Plan (PSIP) already lists the Isimba hydropower plant as a public project, long before the IPP or PPP approach had been publicly dismissed by the government.
12. With a total final price of $300 million (installation + capacity payments), the Kiira 50 MW plant was four times as expensive as Aggreko's plant in Rwanda at $74 million and twice as expensive as the $160 million for the Lugogo 50 MW. Furthermore, stakeholders and observers characterized the procurement process "as rushed and shrouded in secrecy," which led the World Bank to pull out and instead provide IDA support for the $206 million Mutundwe plant, which was commissioned in 2008 (http://www.theeastafrican.co.ke/news/EAC-foots-huge-energy-bill-as--thermal-plants-have-a-field-day/-/2558/1226360/-/7dtern/-/index.html, accessed February 1, 2015).
13. http://www.getfit-uganda.org/information-for-developers/get-fit-solar-facility-eoi/, accessed February 1, 2015.
14. For small hydropower and bagasse in 2013.
15. Under the EPC model, the government or public utility hires a private firm to build the plant, but ownership resides with the state. This is distinctly not an IPP, where the utility purchases electricity from a private firm that builds, owns, and operates the power plant in question.
16. The direct awards of the Karuma, Isimba, and Ayago HPPs may not be in line with the Public Procurement and Disposal of Public Assets Act (PPDA, 2003). In this act, which defines the rules of procurement for public entities, direct awards are lawful only in specified circumstances. Section 85 of the PPDA stipulates: "(1) Direct procurement or disposal is a sole source procurement or disposal method for procurement or disposal requirements where exceptional circumstances prevent the use of competition; (2) Direct procurement or disposal shall be used to achieve efficient and timely procurement or disposal, where the circumstances do not permit a competitive method." Due to the existing energy surplus at the time of the award, it can hardly be argued that circumstances did not permit a competitive tender.
17. Electricity Regulatory Authority, personal communication, November 2014.
18. Other public projects funded and implemented in cooperation with Chinese investors and contractors are dealt with in the section on Chinese-funded projects.
19. The Nalubaale and Kiira HPPs have the capacity of running a higher peak capacity, but 220 MW has been chosen to match the 800 cubic meters per second (m^3/s) average release from Lake Victoria (140 MW) that is currently permitted and the current plant factor of 62 percent (data from May 2012–February 2013).
20. The 1929 Nile Waters Agreement, amended in 1953, was concluded between Egypt and Great Britain, which represented its then-protectorate, Uganda. The agreement stipulates that no works are to be undertaken on the Nile, its tributaries, or the Lake Basin that would reduce the volume of water reaching Egypt. These agreements are currently being challenged by Ugandan officials claiming that Uganda was not

effectively represented at the conclusion of this agreement and cannot be bound to supranational legal acts of the British colonial government. However, it seems that Uganda confirmed commitment to the 1953 agreement in a bilateral memorandum of understanding in 1991.

21. GETFiT Uganda is supported by the United Kingdom (through the Department for International Development [DfID]/Department of Energy and Climate Change [DECC]), Norway, Germany, and the European Union's Infrastructure Trust Fund. It also cooperates with a World Bank partial risk guarantee facility. http://www.getfit-uganda.org/, accessed February 1, 2015.
22. No IPP that reached financial close between 2007 and 2012 utilized the Ugandan renewable energy feed-in tariff (REFiT), but tariff levels were individually negotiated between the developer or sponsor and ERA, the UETCL, and the MEMD.
23. Fifteen bids were submitted in round 1; 8 in round 2; and 18 in round 3. GETFiT policy allows rejected projects to apply again. Overall, more than 30 projects applied.
24. Financial close for the Karuma and Isimba HPPs, following parliamentary approval of their financing conditions, is still a matter of debate. Whereas some representatives of the MEMD claim the deal is "sealed," other sector stakeholders and development partners have not been informed of the final decision. The 2014 Sector Performance Report also does not announce the conclusion of the financing agreement. One remaining point of discussion is allegedly the collateral demanded for the loans made by the China ExIm Bank. That collateral is in the form of future oil revenues.
25. http://www.newvision.co.ug/D/8/21/655225, accessed February 1, 2015.
26. Before this time, procedures primarily prescribed by multilateral financing institutions had been utilized, as exemplified in the case of Bujagali.
27. http://www.independent.co.ug/cover-story/7709-chinese-firm-warns-uganda-on-karuma?format=pdf, accessed February 1, 2015.
28. According to media reports, the bidder, CWE, had unduly relied on capacities and guarantees of its parent company, Three Gorges Hydro, and made false statements regarding reference projects.
29. Another chamber of the High Court found no violations of procurement procedures. In late 2014, the case was still pending before the East African Court of Justice, an organ of the East African Community.
30. Brazil, Russian Federation, India, China, and South Africa.
31. Personal communication.
32. http://allafrica.com/stories/201310070369.html, accessed February 1, 2015.
33. London Interbank Offered Rate.
34. The JICA and the Japanese developers' consortium cited environmental concerns as their reasons for renouncing the project. While these (valid) concerns may have contributed to the decision, it seems apparent that the government's involvement of another developer led to frustrated expectations and, consequently, the decision to abandon.
35. A third possible pillar for future project implementation is suggested by the recently initiated PPP projects, Muzizi and Nyagak III. At the time of writing, however, it is too early to say whether PPPs will become a steady part of Uganda's approach to capacity procurement.
36. A time frame of six years obviously excludes the time "lost" during the preceding struggle to make an award following the international competitive bidding process.

37. http://www.wsj.com/articles/privately-funded-electricity-too-expensive-for-uganda-president-says-1413827013, accessed February 1, 2015.
38. $0.589 for hydro and $0.596 for bagasse projects.

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APPENDIX A

Total Investments in Electric Power Generation in Sub-Saharan Africa

Table A.1 Total Annual Investments in Electric Power Generation, by Country or Territory: Sub-Saharan Africa, 1990–2014
US$, millions

Country or territory	*Cumulative, 1990–2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
Angola	—	—	—	45.0	—	—	—	—	—	—	—	—	—	—	163.2
Benin	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Botswana	—	—	—	—	—	—	—	—	—	1,252.0	—	—	—	—	—
Burkina Faso	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Burundi	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Cabo Verde	—	—	—	—	—	—	—	—	6.6	—	80.0	—	—	—	—
Cameroon	—	—	—	—	—	—	—	—	—	126.0	342.0	637.0	—	—	—
Canary Islands	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Central African Republic	—	—	—	—	—	—	—	—	—	—	—	25.0	—	—	—
Ceuta	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Chad	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Comoros	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Congo, Dem. Rep.	—	—	—	—	—	—	—	—	—	341.0	—	367.5	—	—	40.3
Congo, Rep.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Côte d'Ivoire	465.0	—	—	—	—	—	—	—	—	134.0	—	—	571.0	341.0	—
Djibouti	14.8	—	—	9.9	18.9	—	—	—	—	—	—	—	—	—	—
Equatorial Guinea	—	—	—	—	—	—	—	—	—	—	356.6	—	—	—	—
Eritrea	17.0	—	68.8	—	—	—	—	—	—	—	—	—	—	—	—
Ethiopia	233.0	—	—	—	—	324.0	—	—	—	244.5	—	123.0	951.0	—	420.3
Gabon	—	—	—	—	—	—	—	—	—	—	398.0	—	—	—	—
Gambia, The	—	—	—	—	—	36.2	—	—	—	—	—	—	—	—	—
Ghana	411.3	—	—	—	—	—	—	200.0	—	761.0	—	—	—	330.0	—

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Table A.1 Total Annual Investments in Electric Power Generation, by Country or Territory: Sub-Saharan Africa, 1990–2014 *(continued)*
US$, millions

Country or territory	*Cumulative, 1990–2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
Guinea	107.3	—	—	—	—	—	—	—	—	—	446.2	—	—	—	—
Guinea-Bissau	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Kenya	333.7	—	—	—	—	—	—	51.1	205.0	188.5	—	126.2	284.0	258.0	900.0
Lesotho	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Liberia	—	—	—	—	—	—	—	—	—	—	—	—	—	—	12.8
Madagascar	92.0	—	—	—	—	23.1	—	17.8	—	—	—	—	—	—	—
Madeira	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Malawi	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mali	144.4	—	—	—	—	—	—	—	—	—	—	—	—	467.0	—
Mauritania	—	—	—	—	23.8	—	—	—	—	—	—	—	—	—	—
Mauritius	317.4	—	—	—	95.2	120.4	—	—	—	—	—	—	—	—	—
Mayotte	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Melilla	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mozambique	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Namibia	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Niger	—	—	—	—	—	—	—	—	125.0	—	—	20.5	—	—	—
Nigeria	—	240.0	1,182.7	—	—	—	—	—	540.0	—	660.0	—	—	1,753.0	—
Réunion	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Rwanda	—	—	—	—	—	—	—	—	—	—	—	200.0	—	—	—
Saint Helena	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
São Tomé and Príncipe	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Senegal	65.0	—	—	—	—	110.0	—	—	—	—	22.0	—	—	254.3	163.5

table continues next page

Table A.1 Total Annual Investments in Electric Power Generation, by Country or Territory: Sub-Saharan Africa, 1990–2014 *(continued)*
US$, millions

Country or territory	*Cumulative, 1990–2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
Seychelles	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Sierra Leone	204.1	—	—	—	33.0	—	15.0	—	35.4	—	1.6	30.0	—	—	—
Somalia	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
South Africa	—	—	—	—	—	13.7	9.9	—	—	—	3,076.5	—	6,164.4	4,213.8	3,405.4
Sudan	—	300.0	—	—	1,071.4	221.5	—	—	361.0	87.0	—	—	—	—	—
Swaziland	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Tanzania	127.2	316.0	—	—	—	32.0	123.2	—	—	—	—	—	—	—	—
Togo	—	—	—	—	—	—	—	—	196.0	—	—	—	—	—	308.0
Uganda	274.0	—	—	56.0	—	—	56.0	860.0	180.7	97.5	—	—	41.5	—	1,688.4
Western Sahara	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Zambia	—	—	—	—	—	—	—	—	—	279.0	—	—	72.0	—	821.5
Zimbabwe	—	—	—	—	—	—	—	—	—	—	—	—	—	389.0	—
Total	**2,806.2**	**856.0**	**1,251.5**	**110.9**	**1,242.4**	**880.9**	**204.1**	**1,128.9**	**1,649.6**	**3,510.5**	**5,382.9**	**1,529.2**	**8,083.9**	**8,006.1**	**8,875.6**
Total without South Africa	**2,806.2**	**856.0**	**1,251.5**	**110.9**	**1,242.4**	**867.2**	**194.2**	**1,128.9**	**1,649.6**	**3,510.5**	**2,306.4**	**1,529.2**	**1,919.5**	**3,792.3**	**5,470.2**

Sources: IPP and China investment totals are based on extensive primary and secondary source data (including the Private Participation in Infrastructure database, AidData, and direct correspondence with country and project contacts). ODA, concessionary DFI/MFI, and Arab funding have been sourced by AidData (for which OECD data are a reference point) and cross-checked with secondary sources. The authors have also actively engaged with researchers at both AidData, OECD, and those involved in AICD.
Note: ODA is defined as those flows to countries and territories on the DAC List of ODA Recipients (available at http://www.oecd.org/dac/stats/daclist.htm) and to multilateral development institutions which are provided by official agencies, including state and local governments, or by their executive agencies. AICD = Africa Infrastructure Country Diagnostic; DAC = Development Assistance Committee; DFI = development finance institution; IPPs = independent power projects; MFI = multilateral finance institution; ODA = official development assistance; OECD = Organisation for Economic Co-operation and Development.
"—" indicates 0 investment.

Table A.2 Total Annual Investments in Electric Power Generation, by Source of Funding: Sub-Saharan Africa, 1990–2013
US$, millions

Source of funding	*Cumulative, 1990–2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*
IPPs	1,427.4	556.0	462.0	101.0	95.2	312.3	189.1	1,077.8	1,121.7	686.0	843.0	356.2	6,561.9	5,857.1
ODA (OECD)	295.4	—	—	—	—	324.0	—	51.1	18.0	58.5	—	—	—	—
DFI	947.6	—	18.0	9.9	530.7	13.0	15.0	—	129.0	282.0	2,679.1	—	—	—
Arab flows	135.6	—	50.8	—	616.4	10.1	—	—	381.0	—	—	20.5	—	—
China flows	—	300.0	720.7	—	—	221.5	—	—	—	2,484.0	1,860.8	1,152.5	1,522.0	2,149.0

Sources: IPP and China investment totals are based on extensive primary and secondary source data (including the Private Participation in Infrastructure database, AidData, and direct correspondence with country and project contacts). ODA, concessionary DFI/MFI, and Arab funding have been sourced by AidData (for which OECD data are a reference point) and cross-checked with secondary sources. The authors have also actively engaged with researchers at both AidData, OECD, and those involved in AICD.
Note: ODA is defined as those flows to countries and territories on the DAC List of ODA Recipients (available at http://www.oecd.org/dac/stats/daclist.htm) and to multilateral development institutions which are provided by official agencies, including state and local governments, or by their executive agencies. AICD = Africa Infrastructure Country Diagnostic; DAC = Development Assistance Committee; DFI = development finance institution; IPPs = independent power projects; MFI = multilateral finance institution; ODA = official development assistance; OECD = Organisation for Economic Co-operation and Development.
"—" indicates 0 investment.

Table A.3 Total Annual Investments in Electric Power Generation, by Source of Funding: Sub-Saharan Africa (Excluding South Africa), 1990–2013
US$, millions

Source of funding	*Cumulative, 1990–2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*
IPPs	1,427.4	556.0	462.0	101.0	95.2	298.6	179.2	1,077.8	1,121.7	686.0	444.0	356.2	397.5	1,643.3
ODA (OECD)	295.4	—	—	—	—	324.0	—	51.1	18.0	58.5	—	—	—	—
DFI	947.6	—	18.0	9.9	530.7	13.0	15.0	—	129.0	282.0	1.6	—	—	—
Arab flows	135.6	—	50.8	—	616.4	10.1	—	—	381.0	—	—	20.5	—	—
China flows	—	300.0	720.7	—	—	221.5	—	—	—	2,484.0	1,860.8	1,152.5	1,522.0	2,149.0

Sources: IPP and China investment totals are based on extensive primary and secondary source data (including the Private Participation in Infrastructure database, AidData, and direct correspondence with country and project contacts). ODA, concessionary DFI/MFI, and Arab funding have been sourced by AidData (for which OECD data are a reference point) and cross-checked with secondary sources. The authors have also actively engaged with researchers at both AidData, OECD, and those involved in AICD.
Note: ODA is defined as those flows to countries and territories on the DAC List of ODA Recipients (available at http://www.oecd.org/dac/stats/daclist.htm) and to multilateral development institutions which are provided by official agencies, including state and local governments, or by their executive agencies. AICD = Africa Infrastructure Country Diagnostic; DAC = Development Assistance Committee; DFI = development finance institution; IPPs = independent power projects; MFI = multilateral finance institution; ODA = official development assistance; OECD = Organisation for Economic Co-operation and Development.
"—" indicates 0 investment.

APPENDIX B

Government Investments in Electric Power Generation in Sub-Saharan Africa

Table B.1 Government Investments in Electric Power Generation, by Country or Territory: Sub-Saharan Africa, Cumulative 1990–2013

Country or territory	*Total installed capacity (MW)*	*Investment (US$, millions)*
Angola	841	1,809.1
Benin	145	189.8
Botswana	76	317.1
Burkina Faso	177	279.0
Burundi	2	2.9
Cabo Verde	74	94.1
Cameroon	307	444.3
Central African Republic	0	—
Chad	99	143.3
Comoros	22	31.3
Congo, Dem. Rep.	0	—
Congo, Rep.	390	608.8
Côte d’Ivoire	0	—
Djibouti	0	—
Equatorial Guinea	93	126.6
Eritrea	38	58.0
Ethiopia	1,048	2,818.0
Gabon	0	—
Gambia, The	60	86.6
Ghana	379	546.6
Guinea	99	156.4
Guinea-Bissau	0	—
Kenya	464	1,022.0
Lesotho	0	—
Liberia	0	—

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Table B.1 Government Investments in Electric Power Generation, by Country or Territory: Sub-Saharan Africa, Cumulative 1990–2013 *(continued)*

Country or territory	*Total installed capacity (MW)*	*Investment (US$, millions)*
Madagascar	300	549.5
Malawi	166	444.2
Mali	73	104.9
Mauritania	13	18.8
Mauritius	156	225.3
Mozambique	24	35.3
Namibia	238	261.3
Niger	62	90.4
Nigeria	1,298	2,043.8
Rwanda	59	99.5
Saint Helena	2	2.9
São Tomé and Príncipe	24	37.9
Senegal	250	361.1
Seychelles	62	90.2
Sierra Leone	7	43.6
Somalia	10	14.5
South Africa	10,098	13,954.0
Sudan and South Sudan	502	508.3
Swaziland	0	—
Tanzania	726	1,322.5
Togo	0	—
Uganda	90	129.6
Western Sahara	2	2.9
Zambia	285	763.3
Zimbabwe	0	—
Total, SSA	**18,761**	**29,837.9**
Total, SSA, excluding South Africa	**8,663**	**15,883.9**

Note: Total installed capacity from 1990 to 2012 is based on data from the U.S. Energy Information Administration. Figures for 2013 were taken from World Bank's own database. The total government or utility investment over this period was calculated by taking the total capacity added between 2013 and 1990 and subtracting the megawatts known because of IPPs, Chinese or ODA/DFI/Arab investment in the country. The number that remains is treated as government investment.
Any government numbers that were independently verified were used. Where specific projects were not available to cross-check for government investment, investment numbers were assigned based on average costs per technology in Sub-Saharan Africa. This is at best an estimate of government investment, and anyone using these numbers should look at all the assumptions carefully. DFI = development finance institution; IPPs = independent power projects; MW = megawatt; ODA = official development assistance; SSA = Sub-Saharan Africa. "—" indicates 0 investment.

APPENDIX C

Investments in Electric Power Generation in Sub-Saharan Africa Financed by Official Development Assistance and Development Finance Institutions

Table C.1 Official Development Assistance (ODA) and Development Finance Institution (DFI) Investments in Electric Power Generation, by Country and Project: Sub-Saharan Africa, 1990–2012

Project	*Technology*	*Capacity (MW)*	*Year of investment*	*Total investment (US$, millions)*	*Type of financing*	*Agency*
Botswana						
Morupule B Power Station	Coal	600	2009	214.0	Concession loan	AfDB
Morupule B Power Station	Coal		2009	68.0	Concession loan	WB
Burkina Faso						
Samendini Dam Project	Hydro	2.5	2008	44.0	Concession loan	Middle East (BADEA, KDF, SFD, Abu Dhabi)
Samendini Dam Project	Hydro		2008	7.0	Concession loan	OFID
Samendini Dam Project	Hydro		2008	36.5	Concession loan	IsDB
Samendini Dam Project	Hydro		2008	8.0	Concession loan	Bank of West Africa
Samendini Dam Project	Hydro		2008	8.1	Concession loan	Entrepreneurship and Development Bank of Western Africa Economic Association
Samendini Dam Project	Hydro		2008	26.4		Government of Burkina Faso

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Table C.1 Official Development Assistance (ODA) and Development Finance Institution (DFI) Investments in Electric Power Generation, by Country and Project: Sub-Saharan Africa, 1990–2012 *(continued)*

Project	*Technology*	*Capacity (MW)*	*Year of investment*	*Total investment (US$, millions)*	*Type of financing*	*Agency*
Cabo Verde						
Extension of Thermal Power Station at Santiago Island	Diesel	20	2008	6.6	Concession loan	African Development Fund
Djibouti						
Boulaos Power Generating Project	Diesel	10	1999	14.8	Concession loan	KDF
Boulaos Power Generating Station Project (Fourth Phase)	Diesel	14	2004	13.9	Concession loan	AFESD
Boulaos Power Generating Station Project (Fourth Phase)	Diesel		2004	5.0	Concession loan	OFID
Boulaos Power Generating Station Project (Third Phase)	Diesel	21	2003	9.9	Concession loan	AFESD
Eritrea						
Blesa Power Station Expansion	Diesel	15	1995	17.0	Concession loan	KDF
Hirgigo Thermal Power Plant Project	Diesel	88	2002	6.0	Concession loan	OFID
Hirgigo Thermal Power Plant Project	Diesel		2002	25.8	Concession loan	KDF
Hirgigo Thermal Power Plant Project	Diesel		2002	12.0	Concession loan	BADEA
Hirgigo Thermal Power Plant Project	Diesel		2002	25.0	Concession loan	ADFD
Ethiopia						
Ashegoda Wind Farm in Tigray	Wind	120	2009	58.5	ODA loan	France (AFD)
Gilgel Gibe II Project	Hydro	420	2005	264.0	Concession loan	Italy
Gilgel Gibe II Project	Hydro		2005	60.0	Concession loan	EIB
Gilgel Gibe I Hydroelectric Plant	Hydro	184	1997	189.0	Concession loan	WB (IDA)
Gilgel Gibe I Hydroelectric Plant	Hydro		1997	44.0	Concession loan	EIB and Nordic
Ghana						
Takoradi Thermal Power Plant	Combined cycle	300	1993/94	170.7	Concession loan	WB (IDA)
Takoradi Thermal Power Plant	Combined cycle		1993/94	39.5	Concession loan	EIB

table continues next page

Table C.1 Official Development Assistance (ODA) and Development Finance Institution (DFI) Investments in Electric Power Generation, by Country and Project: Sub-Saharan Africa, 1990–2012 *(continued)*

Project	*Technology*	*Capacity (MW)*	*Year of investment*	*Total investment (US$, millions)*	*Type of financing*	*Agency*
Takoradi Thermal Power Plant	Combined cycle		1993/94	9.8	Concession loan	BADEA
Takoradi Thermal Power Plant	Combined cycle		1993/94	21.5	Concession loan	KDF
Takoradi Thermal Power Plant	Combined cycle		1993/94	29.9	Concession loan	France
Takoradi Thermal Power Plant	Combined Cycle		1993/94	30.0	Concession loan	UK
Guinea						
Hydroelectricity in Garafiri	Hydro	75	1999	21.1	ODA grant	Canada (CIDA)
Hydroelectricity in Garafiri	Hydro		1999	12.0	Concession loan	BADEA
Hydroelectricity in Garafiri	Hydro		1999	4.1	Concession loan	IsDB
Hydroelectricity in Garafiri	Hydro		1999	10.9	Concession loan	IsDB
Hydroelectricity in Garafiri	Hydro		1999	20.4	Concession loan	KDF
Hydroelectricity in Garafiri	Hydro		1999	9.8	Concession loan	KDF
Hydroelectricity in Garafiri	Hydro		1999	29.0	Concession loan	SFD
Kenya						
(Sang'oro Power Plant) Sondu-Miriu Hydropower Project	Hydro	60	2007	51.1	Concession loan	Japan (JICA)
Madagascar						
Energy Sector Development Project	Diesel	19.6	1996	92.0	Concession loan	WB and EIB
Andekaleka Hydroelectric (Phase II)	Hydro	29	2005	6.5	Concession loan	OFID
Andekaleka Hydroelectric (Phase II)	Hydro		2005	10.1	Concession loan	KDF
Andekaleka Hydroelectric (Phase II)	Hydro		2005	6.5	Concession loan	BADEA
Mali						
Power Plant at Manantali Dam (plant and turbines only)	Hydro	200	1997	144.4	Concession loan	IDA, BOAD, CIDA, AFD, BID, KfW (multilateral)

table continues next page

Table C.1 Official Development Assistance (ODA) and Development Finance Institution (DFI) Investments in Electric Power Generation, by Country and Project: Sub-Saharan Africa, 1990–2012 *(continued)*

Project	*Technology*	*Capacity (MW)*	*Year of investment*	*Total investment (US$, millions)*	*Type of financing*	*Agency*
Mauritania						
Expansion of Nouadhibou Power Generation Station	Diesel	22	2004	23.8	Concession loan	AFESD
Mauritius						
Fort George Power Station Extension Project	Diesel	30	1996	13.4	Concession loan	KDF
Niger						
Kandadji Dam Project	Hydro	130	2011	20.5	Concession loan	KDF
Kandadji Dam Project	Hydro		2008	15.0	Concession loan	OFID
Kandadji Dam Project	Hydro		2008	20.0	Concession loan	SFD
Kandadji Dam Project	Hydro		2008	50.0	Concession loan	IsDB
Kandadji Dam Project	Hydro		2008	30.0	Concession loan	AfDB
Kandadji Dam Project	Hydro		2008	10.0	Concession loan	BADEA
Rwanda						
Rukarara II Micro Hydro	Hydro	2	2011	1.3	ODA grant	Belgium
Sierra Leone						
Western Area Power Generation (additional loan)	Diesel	16	2010	1.6	Concession loan	SFD
Western Area Power Generation Project	Diesel	16	2006	8.0	Concession loan	BADEA
Western Area Power Generation Project	Diesel	16	2006	7.0	Concession loan	BADEA
Bumbuna Hydro Power Project	Hydro	50	1990	50.7	Concession loan	AfDB
Bumbuna Hydro Power Project	Hydro		1995	28.8	Concession loan	AfDB
Bumbuna Hydro Power Project	Hydro		2005	1.8	Concession loan	AfDB
Bumbuna Hydro Power Project	Hydro		2008	16.4	Concession loan	AfDB
Bumbuna Hydro Power Project	Hydro		2009	1.1	Concession loan	AfDB (NTF)
Bumbuna Hydro Power Project	Hydro		2004	12.9	Concession loan	WB

table continues next page

Table C.1 Official Development Assistance (ODA) and Development Finance Institution (DFI) Investments in Electric Power Generation, by Country and Project: Sub-Saharan Africa, 1990–2012 *(continued)*

Project	*Technology*	*Capacity (MW)*	*Year of investment*	*Total investment (US$, millions)*	*Type of financing*	*Agency*
Bumbuna Hydro Power Project	Hydro		1990	124.6	Concession loan	Italy
Bumbuna Hydro Power Project	Hydro		2005	23.8	Concession loan	Italy
Bumbuna Hydro Power Project	Hydro		2008	18.0	Concession loan	Italy
Bumbuna Hydro Power Project	Hydro		2004	10.2	Concession loan	DFID
Bumbuna Hydro Power Project	Hydro		2006	10.0	Concession loan	OFID
South Africa						
Medupi Power Station	Coal	4,800	2010	1,135.5	Concession loan	AfDB
Medupi Power Station	Coal		2010	1,542.0	Concession loan	World Bank (IBRD)
Sudan						
Merowe Dam	Hydro	1,250	2004	455.0	Concession loan	AFESD
Merowe Dam	Hydro		2004	210.0	Concession loan	SFD
Merowe Dam	Hydro		2004	156.4	Concession loan	KDF
Merowe Dam	Hydro		2004	200.0	Concession loan	ADFD
Merowe Dam	Hydro		2004	50.0	Concession loan	Oman
Expansion of Roseires Dam	Hydro	775	2008	30.0	Concession loan	OFID
Expansion of Roseires Dam	Hydro		2008	73.0	Concession loan	IsDB
Expansion of Roseires Dam	Hydro		2008	36.0	Concession loan	SFD
Expansion of Roseires Dam	Hydro		2008	25.0	Concession loan	ADFD
Expansion of Roseires Dam	Hydro		2008	197.0	Concession loan	AFESD
Uganda						
Power Project 3 (Extension of Owen Falls)	Hydro	200	1994	125.4	Equity, loan	World Bank (IDA)
Power Project 3 (Extension of Owen Falls)	Hydro		1994	15.2	Concession loan	World Bank (IDA)

table continues next page

Table C.1 Official Development Assistance (ODA) and Development Finance Institution (DFI) Investments in Electric Power Generation, by Country and Project: Sub-Saharan Africa, 1990–2012 *(continued)*

Project	*Technology*	*Capacity (MW)*	*Year of investment*	*Total investment (US$, millions)*	*Type of financing*	*Agency*
***Uganda** (cont.)*						
Power Project 3 (Extension of Owen Falls)	Hydro		1994	20.0	Concession loan	IsDB
Power Project 3 (Extension of Owen Falls)	Hydro		1994	45.0	Concession loan	AfDB
Power Project 3 (Extension of Owen Falls)	Hydro		1994	24.6	Concession loan	Norway, Norfund
Power Project 3 (Extension of Owen Falls)	Hydro		1994	21.3	Concession loan	Others (UK, Sweden, Sida, etc.)

Note: ODA, concessionary DFI/MFI, and Arab funding have been sourced by AidData (for which OECD data is a reference point) and cross-checked with secondary sources. ODA is defined as those flows to countries and territories on the DAC List of ODA Recipients (available at http://www.oecd.org/dac/stats/daclist.htm) and to multilateral development institutions provided by official agencies, including state and local governments, or by their executive agencies. Several projects have various investment flows sourced from a number of aid agencies. Each agency's contribution is listed separately. However, the total installed capacity (in megawatts) for the project is listed only once. Empty cells indicate that no information was available. ADFD = Abu Dhabi Fund for Development; AFD = Agence Française de Développement; AfDB = African Development Bank; AFESD = Arab Fund for Economic and Social Development; BADEA = Arab Bank for Economic Development in Africa; BID = Banco Interamericano de Desarrollo; BOAD = West African Development Bank; CIDA = Canadian International Development Agency; DAC = Development Assistance Committee; DFI = development finance institution; DfID = Department for International Development; EIB = European Investment Bank; IBRD = International Bank for Reconstruction and Development; IDA = International Development Association; IsDB = Islamic Development Bank; JICA = Japan International Cooperation Agency; KDF = Kuwait Development Fund; KfW = Kreditanstalt für Wiederaufbau; MFI = multilateral finance institution; MW = megawatt; NTF = Nordic Trust Fund; ODA = official development assistance; OECD = Organisation for Economic Co-operation and Development; OFID = OPEC Fund for International Development; SFD = Saudi Fund for Development; Sida = Swedish International Development Cooperation Agency; WB = World Bank.

APPENDIX D

Investments in Electric Power Generation in Sub-Saharan Africa Financed by Chinese Sources

Table D.1 Investments Funded by Chinese Sources, by Country and Project: Sub-Saharan Africa, 1990–2014

Country	*Project*	*Technology*	*Capacity (MW)*	*Financial close*	*Project status*	*Total investment (US$, millions)*
Angola	CIF Cement	Hydro, large	35	2014	Operational	73.4
Botswana	Morupule B Power Station	Coal	600	2009	Operational/construction	970.0
Cameroon	Memve'ele Hydropower Project	Hydro	201.2	2011	Construction	637.0
Central African Republic	Boali No. 3 Hydropower Plant	Hydro, small	9.6	2011	Operational	25.0
Congo, Dem. Rep.	Zongo-II Hydropower Scheme	Hydro, large	150	2011	Construction	367.5
Congo, Rep.	Imboulou Dam	Hydro, large	120	2009	Operational	341.0
Congo, Rep.	Liouesso Hydropower Station	Hydro, small	19.2	2014	Construction	40.3
Côte d'Ivoire	Soubré Hydropower Project	Hydro, large	270	2012	Construction	571.0
Equatorial Guinea	Malabo Power Plant Expansion	CCGT + OCGT	84	2010	Operational	99.6
Equatorial Guinea	Djiploho Hydropower Project	Hydro, large	120	2010	Operational	257.0
Ethiopia	Fan Hydropower Project	Hydro, large	97	2009	Operational	186.0
Ethiopia	Adama Wind Farm	Wind, onshore	50	2011	Operational	123.0
Ethiopia	Genale (GD-3) Multipurpose	Hydro, large	245	2012	Construction	451.0
Ethiopia	Gilgel Gibe III	Hydro, large	400	2012	Operational	500.0
Ethiopia	Adama Wind Farm II	Wind, onshore	100	2014	Operational	293.3
Ethiopia	Messabo Harrena Wind Farm	Wind, onshore	51	2014	Construction	127.0
Gabon	Poubara Hydropower Project	Hydro, large	160	2010	Operational	398.0
Ghana	Bui Hydropower Project	Hydro, large	400	2009	Operational	621.0
Guinea	Kaleta Hydropower Project	Hydro, large	240	2010	Construction	446.2
Mali	Gouina Hydropower Project	Hydro	147	2013	Construction	467.0
Nigeria	Omotosho Power Plant Phase I	OCGT + CCGT	335	2002	Operational	361.0
Nigeria	Papalanto Power Gas Turbine Power Plant, in Ogun	OCGT + CCGT	335	2002	Operational	359.7
Nigeria	Omotosho Power Plant II (NIPP)	OCGT + CCGT	513	2010	Operational	660.0

table continues next page

Table D.1 Investments Funded by Chinese Sources, by Country and Project: Sub-Saharan Africa, 1990–2014 *(continued)*

Country	*Project*	*Technology*	*Capacity (MW)*	*Financial close*	*Project status*	*Total investment (US$, millions)*
Nigeria	Zungeru Hydropower Project	Hydro	700	2013	Construction	1,293.0
Sudan	Al Fulah	Natural gas	105	2001	Operational	300.0
Sudan	Garri (Qarre) I & II, at El Gaili	CCGT	300	2005	Operational	221.5
Sudan	Hydraulic Works for Merowe Dam and HPP Project	Hydro	12.5	2009	Operational	87.0
Togo/Benin	Adjarala	Hydro	147	2014		308.0
Uganda	Isimba Hydropower Project	Hydro	183	2015	Loan agreement signed	556.0
Uganda	Karuma Hydropower Project	Hydro	600	2014	Loan agreement in process	1,688.4
Zambia	Kariba North Bank Power Station Extension Project	Hydro	360	2009	Operational	279.0
Zambia	Mazabuka	Coal	300	2014	Construction, but financing not complete	560.0
Zambia	Lunzua	Hydro, small	14.8	2014	Operational	31.5
Zimbabwe	Kariba South Bank Power Station Extension Project	Hydro	300	2013	Construction	389.0

Note: CCGT = combined-cycle gas turbine; HFO = heavy fuel oil; MW = megawatt; OCGT = open-cycle gas turbine.

APPENDIX E

Independent Power Projects in Sub-Saharan Africa

Table E.1 IPP Investments in Angola, by Project

Project information	*Project name 1*	*Project name 2*
	Chicapa Hydroelectric Plant	**Biocom (Malanje)**
Capacity (MW)	16	30
Technology	Hydro, small (<20 MW)	Waste/bagasse
Total investment (US$, millions)	45.0	89.8
Year of financial close	2003	2014
Commercial operation date	2008	
Project status	Operational	Operational
Procurement method	Direct negotiation	Direct negotiation
Number of bids		
Contract period (years)	40	
Contract type	Build-operate-transfer	
Sponsors/developer	ALROSA Co. Ltd. (Almazy Rossii-Sakha Company) (55%—Russian Federation)	
Engineering, procurement, and construction		
Fuel arrangement		
Debt-equity ratio		
Local shareholder equity (entity, US$, millions)		
Foreign shareholder equity (entity, US$, millions)		
DFI agency and financing method		
Total DFI financing (US$, millions)		
ODA grants (US$, millions)		
Local credit enhancements and security arrangements		
Foreign credit enhancements and security arrangements		

Note: Empty cells indicate that no information was available. DFI = development finance institution; IPP = independent power project; MW = megawatt; ODA = official development assistance.

Table E.2 IPP Investments in Cabo Verde, by Project

Project information	*Project name*
	Electra Cabeolica Wind Project
Capacity (MW)	25.5
Technology	Wind, onshore
Total investment (US$, millions)	80.0
Year of financial close	2010
Commercial operation date	2010
Project status	Operational
Procurement method	
Number of bids	
Contract period (years)	20
Contract type	Build-own-operate
Sponsors/developer	Electra (Cabo Verde), Africa Finance Corporation (Nigeria)
Engineering, procurement, and construction	
Fuel arrangement	
Debt-equity ratio	
Local shareholder equity (entity, US$, millions)	
Foreign shareholder equity (entity, US$, millions)	
DFI agency and financing method	EIB (loan, $39 million, 2010), AfDB (loan, $19 million, 2010)
Total DFI financing (US$, millions)	58.0
ODA grants (US$, millions)	
Local credit enhancements and security arrangements	Variable government payments
Foreign credit enhancements and security arrangements	

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; DFI = development finance institution; EIB = European Investment Bank; IPP = independent power project; MW = megawatt; ODA = official development assistance.

Table E.3 IPP Investments in Cameroon, by Project

Project information	*Project name 1*	*Project name 2*
	Dibamba Power Plant	**Kribi Power Plant**
Capacity (MW)	88	216
Technology	HFO/MSD	CCGT
Total investment (US$, millions)	126.0	342.0
Year of financial close	2009	2010
Commercial operation date	2009	2013
Project status	Operational	Operational
Procurement method	Direct negotiation	Direct negotiation
Number of bids		
Contract period (years)	20	20
Contract type	Build-operate-transfer	Build-operate-transfer
Sponsors/developer	AES Corporation (56%, United States), Cameroon (44%)	KPDC was 56% owned by AES, with the remaining 44% in the hands of the Cameroon government. It was built by Finland's Wartsila, running on natural gas from the offshore Sanaga-South field operated by Cameroon's state oil company, SNH, and independent producer Perenco—the first major commercial development of Cameroon's substantial gas reserves. In November 2013, AES announced it would sell its stake in Cameroon to Actis (Globeleq parent company), a global pan-emerging market investor, for $220 million of net equity proceeds. Sale was completed in 2014.
Engineering, procurement, and construction		Wartsila
Fuel arrangement	Heavy fuel oil/tolling agreement with AES Sonel as toller	Gas supply agreement has been signed with a state-owned gas supplier.
Debt-equity ratio		75/25
Local shareholder equity (entity, US$, millions)		
Foreign shareholder equity (entity, US$, millions)		
DFI agency and financing method	IFC (loan, $31 million, 2010), AfDB (loan, $31 million, 2010), FMO (loan, $31 million, 2010)	AfDB (loan, $57 million, 2011), EIB (loan, $41 million, 2012), other (loan, $23 million, 2012), IDA (guarantee, $82 million, 2012), IFC (loan, $77 million, 2012)
Total DFI financing (US$, millions)	93.0	198.0
ODA grants (US$, millions)		
Local credit enhancements and security arrangements		Sovereign guarantee
Foreign credit enhancements and security arrangements	Typical project finance security agreements implemented but details not made public	WB partial risk guarantees (enabled local bank participation)

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; CCGT = combined-cycle gas turbine; DFI = development finance institution; EIB = European Investment Bank; FMO = Netherlands Development Finance Company; HFO = heavy fuel oil; IDA = International Development Association; IFC = International Finance Corporation; IPP = independent power project; KPDC = Kribi Power Development Company; MSD = medium-speed diesel; MW = megawatt; ODA = official development assistance; WB = World Bank.

Table E.4 IPP Investments in Côte d'Ivoire, by Project

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*	*Project name 6*
	Compagnie Ivoirienne de Production d'Électricité (CIPREL)	**Compagnie Ivoirienne de Production d'Électricité (CIPREL)**	**Azito Power Project**	**Compagnie Ivoirienne de Production d'Électricité (CIPREL)**	**Azito Power Project**	**Compagnie Ivoirienne de Production d'Électricité (CIPREL)**
Capacity (MW)	99	111	288	111	146	111
Technology	OCGT	OCGT	OCGT	OCGT	OCGT + CCGT	OCGT + CCGT
Total investment (US$, millions)	108.0	134.0	223.0	134.0	207.0	134.0
Year of financial close	1994	1997	1999	2009	2013	2013
Commercial operation date	1995		2000			
Project status	Operational, planning/reached financial close	Operational, planning/reached financial close	Operational	Operational	Under construction	Reached financial close
Procurement method	Direct negotiation	Direct negotiation	International competitive bid	Direct negotiation	International competitive bid	Direct negotiation
Number of bids			3			
Contract period (years)	19		24			
Contract type	Build-own-operate-transfer		Build-own-operate-transfer			
Sponsors/developer	SAUR International with 88% (a joint venture between French SAUR Group owned by Bouygues, 65%, and EDF, 35%), with BOAD, Proparco, and IFC holding the remaining 12%. In 2005, all shares sold to Bouygues (France, 98%), except BOAD (2%).	SAUR International with 88% (a joint venture between French SAUR Group owned by Bouygues, 65%, and EDF, 35%), with BOAD, Proparco, and IFC holding the remaining 12%. In 2005, all shares sold to Bouygues (France, 98%), except BOAD (2%).	Globeleq (77%, United Kingdom), Aga Khan Fund (Switzerland)	SAUR International with 88% (a joint venture between French SAUR Group owned by Bouygues, 65%, and EDF, 35%), with BOAD, Proparco, and IFC holding the remaining 12%. In 2005, all shares sold to Bouygues (France, 98%), except BOAD (2%).		SAUR International with 88% (a joint venture between French SAUR Group owned by Bouygues, 65%, and EDF, 35%), with BOAD, Proparco, and IFC holding the remaining 12%. In 2005, all shares sold to Bouygues (France, 98%), except BOAD (2%).

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Table E.4 IPP Investments in Côte d'Ivoire, by Project *(continued)*

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*	*Project name 6*
Engineering, procurement, and construction						
Fuel arrangement	Government procures fuel	Government procures fuel	Government procures fuel	Government procures fuel	Government procures fuel	Government procures fuel
Debt-equity ratio				70/30		
Local shareholder equity (entity, US$, millions)						
Foreign shareholder equity (entity, US$, millions)						
DFI agency and financing method	BOAD (loan, $9 million, 1994), IFC (loan, $18 million, 1995), IFC (equity, $1 million, 1995), IBRD (loan, $80 million, 1995)		AfDB (loan, $14 million, 1998), IDA (guarantee, $30 million, 1999), IFC (loan, $41 million, 1999), IFC (syndication, $31 million, 1999)			IFC, AfDB, and Proparco
Total DFI financing (US$, millions)	108.0	—	116.0	—	—	—
ODA grants (US$, millions)						
Local credit enhancements and security arrangements			Sovereign guarantee, escrow account equivalent to one month capacity charge			
Foreign credit enhancements and security arrangements			World Bank partial risk guarantee			

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; BOAD = West African Development Bank; CCGT = combined-cycle gas turbine; DFI = development finance institution; EDF = Électricité de France; IBRD = International Bank for Reconstruction and Development; IDA = International Development Association; IFC = International Finance Corporation; IPP = independent power project; MW = megawatt; ODA = official development assistance; OCGT = open-cycle gas turbine. In "Total DFI financing" cells "—" indicates 0 financing.

Table E.5 IPP Investments in The Gambia, by Project

Project information	*Project name*
	Brikama
Capacity (MW)	25
Technology	HFO + MSD/HFO
Total investment (US$, millions)	36.2
Year of financial close	2005
Commercial operation date	2006
Project status	Operational
Procurement method	
Number of bids	
Contract period (years)	
Contract type	
Sponsors/developer	Global Electrical Group (GEG)
Engineering, procurement, and construction	
Fuel arrangement	
Debt-equity ratio	
Local shareholder equity (entity, US$, millions)	
Foreign shareholder equity (entity, US$, millions)	
DFI agency and financing method	
Total DFI financing (US$, millions)	
ODA grants (US$, millions)	
Local credit enhancements and security arrangements	
Foreign credit enhancements and security arrangements	

Note: Empty cells indicate that no information was available. DFI = development finance institution; HFO = heavy fuel oil; IPP = independent power project; MSD = medium-speed diesel; MW = megawatt; ODA = official development assistance.

Table E.6 IPP Investments in Ghana, by Project

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*
	Takoradi II	**Sunon-Asogli Power Plant**	**CENIT Energy**	**Takoradi II**	**Kpone IPP**
Capacity (MW)	220	200	126	110	350
Technology	OCGT/CCGT	OCGT + CCGT	OCGT + CCGT	OCGT + CCGT	CCGT
Total investment (US$, millions)	110.0	200.0	140.0	330.0	900.0
Year of financial close	1999	2007	2009	2013	2014
Commercial operation date	2000	2011	2012	2014	2017
Project status	Operational	Operational	Operational	Under construction	Financial close
Procurement method	Direct negotiation	Direct negotiation	Direct negotiation	Direct negotiation	
Number of bids					
Contract period (years)	25				
Contract type	Build-own-operate-transfer	Build-own-operate	Build-own-operate		
Sponsors/developer	CMS (90%, United States), VRA (10%, Ghana). CMS sold shares to TAQA (90%, United Arab Emirates) in 2007.	Shenzhen Electric (60%, China), China-Africa Development Fund (40%, China)	GECAD (100%, United States)	CMS (90%, United States), VRA (10%, Ghana). CMS sold shares to TAQA (90%, United Arab Emirates) in 2007.	Africa Finance Corporation (AFC) (31.85%), CenPower Holdings Limited (21%), a consortium of Ghanaian investors, Sumitomo Corporation (28%), Mercury Power (15%), and FMO (4.15%)
Engineering, procurement, and construction	Mitsui & Co. (Japan) and KEPCO E&C (Republic of Korea)			Mitsui & Co. (Japan) and KEPCO E&C (Republic of Korea)	
Fuel arrangement	Government procures fuel	Interim fuel agreement for access to West African Gas Pipeline gas		Government procures fuel	
Debt-equity ratio					72/28
Local shareholder equity (entity, US$, millions)		Local strategic investor, Togbe Afede XIV			

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Table E.6 IPP Investments in Ghana, by Project *(continued)*

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*
	Takoradi II *(cont.)*	**Sunon-Asogli Power Plant** *(cont.)*	**CENIT Energy** *(cont.)*	**Takoradi II** *(cont.)*	**Kpone IPP** *(cont.)*
Foreign shareholder equity (entity, US$, millions)					
DFI agency and financing method	IFC (loan, $60 million, 2004)		Other (loan, $67 million, 2008), other (quasi-equity, $10 million, 2008), AfDB (loan, $32 million, 2011)	IFC and a consortium of international development finance institutions led by the FMO. The lenders participating in the consortium include the AfDB, Deutsche Investitions- und Entwicklungs Gesellschafte, Emerging Africa Infrastructure Fund, ICF-Debt Pool, and Proparco. The OPEC Fund for International Development and the Canada Climate Change Program are participating alongside the IFC.	FMO (equity, $10.3 million), DBSA (loan, $53 million), OFID (loan, $7 million), EAIF ($25 million), FMO (loan, $24 million), and others
Total DFI financing (US$, millions)	60.0	—	109.0	347.5	207.0
ODA grants (US$, millions)					
Local credit enhancements and security arrangements	Sovereign guarantee (phase 1), $3 million letter of credit provided by government (phase 1)	Variable government payments			
Foreign credit enhancements and security arrangements					

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; CCGT = combined-cycle gas turbine; DBSA = Development Bank of Southern Africa; DFI = development finance institution; EAIF = Emerging Africa Infrastructure Fund; FMO = Netherlands Development Finance Company; IFC = International Finance Corporation; IPP = independent power project; MW = megawatt; OCGT = open-cycle gas turbine; ODA = official development assistance; OFID = OPEC Fund for International Development; OPEC = Organization of the Petroleum Exporting Countries; VRA = Volta River Authority. In "Total DFI financing" cells "—" indicates 0 financing.

Table E.7A IPP Investments in Kenya, by Project

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*	*Project name 6*
	Mombasa Barge-Mounted Power Project/Westmont	**Iberafrica Power Ltd.**	**Kipevu II/Tsavo**	**Ormat Olkaria III Geothermal Power Plant, OrPower4 (phases 1, 2, and 3)**	**Iberafrica Power Ltd.**	**Mumias Power Plant**
Capacity (MW)	46	44	75	13	12	26
Technology	OCGT	MSD/HFO	MSD/HFO	Geothermal	MSD/HFO	Waste
Total investment (US$, millions)	65.0	50.3	86.0	105.0	13.7	50.0
Year of financial close	1996	1996	1999	1999	1999	2008
Commercial operation date	1997	1997	2001	2000, 2009	2000	2009
Project status	Concluded	Operational	Operational	Operational	Operational	Operational
Procurement method	Direct negotiation	Direct negotiation	International competitive bid	International competitive bid	Direct negotiation	Direct negotiation
Number of bids			3	2		
Contract period (years)	7	7	20	20	15	
Contract type	Build-own-operate	Build-own-operate	Build-own-operate	Build-own-operate	Build-own-operate	Build-own-operate
Sponsors/developer	Westmont Ltd. (Malaysia)	Union Fenosa (80%, Spain), KPLC Pension Fund (Kenya, 20%) since 1997	Cinergy and IPS jointly owned 49.9%. Cinergy sold to Duke Energy in 2005. CDC/Globeleq (30%, United Kingdom), Wartsila (15%, Finland), and IFC (5%) retain remaining shares since 2000.	Ormat Turbines Ltd. (100%, Israel)	Union Fenosa (80%, Spain) and KPLC Pension Fund (20%, Kenya) since 1997	Mumias Sugar Company Ltd. (100%, Kenya)
Engineering, procurement, and construction						

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Table E.7A IPP Investments in Kenya, by Project *(continued)*

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*	*Project name 6*
	Mombasa Barge-Mounted Power Project/Westmont *(cont.)*	**Iberafrica Power Ltd.** *(cont.)*	**Kipevu II/Tsavo** *(cont.)*	**Ormat Olkaria III Geothermal Power Plant, OrPower4 (phases 1, 2, and 3)** *(cont.)*	**Iberafrica Power Ltd.** *(cont.)*	**Mumias Power Plant** *(cont.)*
Fuel arrangement	Originally Westmont was to procure fuel and then pass through to the utility. However, following dispute with fuel supplier about taxes after the first year of operation, the utility took over procurement.	Iberafrica buys fuel and passes cost through to KPLC based on the units generated and specific consumption parameters agreed on in the PPA.	Tsavo buys fuel and passes cost through to KPLC based on the units generated and specific consumption parameters agreed on in the PPA.	The only fuel arrangement per se is that OrPower4 was granted a Geothermal Resource License from the government to which it pays a royalty of sorts ($0.004/kWh or USc 0.4/kWh).	Iberafrica buys fuel and passes cost through to KPLC based on the units generated and specific consumption parameters agreed on in the PPA.	
Debt-equity ratio		72/28	78/22			
Local shareholder equity (entity, US$, millions)		KPLC Staff Pension Fund ($9.4 million in direct loans and guarantees; $5 million through a local Kenyan bank)	9.45			
Foreign shareholder equity (entity, US$, millions)		Union Fenosa (Spain) ($12.7 million in direct loans and $20 million in guarantees)	9.48	Ormat (100%) since 1998—until 2008		

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Table E.7A IPP Investments in Kenya, by Project *(continued)*

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*	*Project name 6*
DFI agency and financing method			IFC (loan, $18 million, 2000), IFC (equity, $2 million, 2000), IFC (quasi-equity, $3 million, 2000), IFC (syndication, $24 million, 2000), IFC (risk management, $2 million, 2001), CDC own account ($13 million), DEG own account (€11 million), DEG syndicated (€2 million)	MIGA (guarantee, $49 million, 2000), MIGA (guarantee, $70 million, 2002), MIGA (guarantee, $89 million, 2009), (guarantee, $110 million, 2011)		
Total DFI financing (US$, millions)	—	—	82.0	—	—	—
ODA grants (US$, millions)	—	—	—	—	—	—
Local credit enhancements and security arrangements		An advance payment cash deposit initially, but Iberafrica presently has no payment security.	Letter of comfort provided by government, escrow account equivalent to one month of capacity charge, and a standby letter of credit equivalent to three months of billing	A standby letter of credit, covering several months of billing (although only finalized at end of 2006)	An advance payment cash deposit initially, but Iberafrica presently has no payment security	Payment guarantee
Foreign credit enhancements and security arrangements				MIGA guarantee		

Note: Empty cells indicate that no information was available. CDC = Commonwealth Development Corporation; DEG = German Investment and Development Corporation; DFI = development finance institution; HFO = heavy fuel oil; IFC = International Finance Corporation; IPP = independent power project; IPS = Industrial Promotion Services; KPLC = Kenya Power and Lighting Company; kWh = kilowatt-hour; MIGA = Multilateral Investment Guarantee Agency; MSD = medium-speed diesel; MW = megawatt; OCGT = open-cycle gas turbine; ODA = official development assistance; PPA = power purchase agreement; USc = U.S. cent. In "Total DFI financing" and "ODA grants" cells "—" indicates 0 financing or grants, respectively.

Table E.7B IPP Investments in Kenya, by Project

Project information	*Project name 7*	*Project name 8*	*Project name 9*	*Project name 10*	*Project name 11*	*Project name 12*
	Rabai Power Plant	**Ormat Olkaria III Geothermal Power Plant, OrPower4 (phases 1, 2, and 3)**	**Iberafrica Power Ltd.**	**Ormat Olkaria III Geothermal Power Plant, OrPower4 (phases 1, 2, and 3)**	**Triumph HFO Power Plant**	**Thika Thermal Power Project**
Capacity (MW)	90	35	52.5	36	83	87
Technology	MSD/HFO and steam cycle	Geothermal	MSD/HFO	Geothermal	MSD/HFO	MSD/HFO
Total investment (US$, millions)	155.0	128.7	59.9	126.2	140.0	144.0
Year of financial close	2008	2009	2009	2011	2012	2012
Commercial operation date	2010	2009	2009	2013	2015	2013
Project status	Operational	Operational	Operational	Operational	Construction	Operational
Procurement method	International competitive bid	Direct negotiation	Direct negotiation	Direct negotiation	International competitive bid	International competitive bid
Number of bids	4				5	9
Contract period (years)	20		25		20	20
Contract type	Build-own-operate-transfer	Build-own-operate	Build-own-operate	Build-own-operate	Build-own-operate	Build-own-operate
Sponsors/developer	Aldwych, 34.5%; BWSC (Danish, but owned by Mitsui of Japan), 25.5%; FMO, 20%; IFU (Danish bilateral lender), 20%	Ormat Turbines Ltd. (100%, Israel)	Union Fenosa (80%, Spain), KPLC Pension Fund (20%, Kenya) since 1997	Ormat Turbines Ltd. (100%, Israel)	Broad Holding (Kenya), Interpel Investments (Kenya), Tecaflex (Kenya), Southern Inter-trade (Kenya)	Melec PowerGen (part of Matelec Group) (90%, Lebanon)
Engineering, procurement, and construction	BWSC, codeveloper, sponsor, and shareholder; EPC, contractor and operations and maintenance contractor				XJ International Engineering Company (wholly owned subsidiary of State Grid Corporation of China)	MAN Diesel (Germany) and Matelec Group

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Table E.7B IPP Investments in Kenya, by Project *(continued)*

Project information	*Project name 7*	*Project name 8*	*Project name 9*	*Project name 10*	*Project name 11*	*Project name 12*
Fuel arrangement	Fuel supply agreement with Kenol of Kenya		Iberafrica buys fuel and passes cost through to KPLC based on the units generated and specific consumption parameters agreed on in the PPA			
Debt-equity ratio	75/25				74/26	75/25
Local shareholder equity (entity, US$, millions)						
Foreign shareholder equity (entity, US$, millions)		Ormat (100%) since 1998—until 2008		Ormat (100%) since 1998—until 2008		
DFI agency and financing method	Other (loan, $126 million, 2008); DEG, 15%; FMO, 25%; EAIF, 25%; Proparco, 25%; European Financing Partners, 10%	MIGA (guarantees, $49 million, 2000; $70 million, 2002; $89 million, 2009), EIB (loan, $155 million, 2010), MIGA (guarantee, $110 million, 2011)		MIGA (guarantees, $49 million, 2000; $70 million, 2002; $89 million, 2009), EIB (loan, $155 million, 2010), MIGA (guarantee, $110 million, 2011)	MIGA (guarantee, $12 million, 2012), IDA (guarantee, $45 million, 2012)	AfDB (loan, €28 million, 2012), IFC (loan, €28 million, 2012), IDA (guarantee, $45 million, 2012), MIGA (guarantee, $62 million, 2012)
Total DFI financing (US$, millions)	126.0	155.0	—	—	—	64.0
ODA grants (US$, millions)	—	—	—	—	—	—

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Table E.7B IPP Investments in Kenya, by Project *(continued)*

Project information	*Project name 7*	*Project name 8*	*Project name 9*	*Project name 10*	*Project name 11*	*Project name 12*
	Rabai Power Plant *(cont.)*	**Ormat Olkaria III Geothermal Power Plant, OrPower4 (phases 1, 2, and 3)** *(cont.)*	**Iberafrica Power Ltd.** *(cont.)*	**Ormat Olkaria III Geothermal Power Plant, OrPower4 (phases 1, 2, and 3)** *(cont.)*	**Triumph HFO Power Plant** *(cont.)*	**Thika Thermal Power Project** *(cont.)*
Local credit enhancements and security arrangements	Support letter from government of Kenya (covers political risk but falls short of being an outright guarantee). KPLC issued a letter of credit equivalent to five months of capacity payments (debt service, fixed costs, and equity returns) and two months of fuel payments	Letter of comfort provided by government, escrow account equivalent to one month of capacity charge, and a standby letter of credit equivalent to three months of billing	An advance payment cash deposit initially, but Iberafrica presently has no payment security.	Letter of comfort provided by government, escrow account equivalent to one month of capacity charge, and a standby letter of credit equivalent to three months of billing		
Foreign credit enhancements and security arrangements					Partial risk guarantees	Partial risk guarantees

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; DEG = German Investment and Development Corporation; DFI = development finance institution; EAIF = Emerging Africa Infrastructure Fund; EIB = European Investment Bank; EPC = engineering, procurement, and construction; FMO = Netherlands Development Finance Company; HFO = heavy fuel oil; IDA = International Development Association; IFC = International Finance Corporation; IFU = Danish Investment Fund for Developing Countries; IPP = independent power project; KPLC = Kenya Power and Lighting Company; MIGA = Multilateral Investment Guarantee Agency; MSD = medium-speed diesel; MW = megawatt; ODA = official development assistance; PPA = power purchase agreement. In "Total DFI financing" and "ODA grants" cells "—" indicates 0 financing or grants, respectively.

Table E.7C IPP Investments in Kenya, by Project

Project information	*Project name 13*	*Project name 14*	*Project name 15*	*Project name 16*
	Kinangop Greenfield Wind Project	**Gulf Power**	**Lake Turkana Wind Power**	**Ormat Olkaria III Geothermal Power Plant, OrPower4 (phases 1, 2, and 3)**
Capacity (MW)	60	80	300	26
Technology	Wind, onshore	MSD/HFO	Wind, onshore	Geothermal
Total investment (US$, millions)	150.0	108.0	861.1	91.1
Year of financial close	2013	2013	2014	2014
Commercial operation date	Delayed	2014	2017	
Project status	Construction/stalled	Operational	Financial close	Operational
Procurement method	REFiT	International competitive bid	Direct negotiation	Direct negotiation
Number of bids		5		
Contract period (years)		20	20	
Contract type	Build-own-operate	Build-own-operate	Build-own-operate	Build-own-operate
Sponsors/developer	Aeolus Kenya, AIIF2, which became involved in the project in 2012 to assist the developer Aeolus Kenya to conclude all material contracts and deliver a bankable project, is the majority owner of the project company, Kinangop Wind Park (KWP), while Norfund held the remaining equity.	Consortium of local investors: Gulf Energy Ltd. and Noora Power Ltd.	KP&P Africa BV, a group of Dutch entrepreneurs, acts with Aldwych International as codevelopers.	
Engineering, procurement, and construction				
Fuel arrangement				
Debt-equity ratio				
Local shareholder equity (entity, US$, millions)				

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Table E.7C IPP Investments in Kenya, by Project *(continued)*

Project information	*Project name 13*	*Project name 14*	*Project name 15*	*Project name 16*
	Kinangop Greenfield Wind Project *(cont.)*	**Gulf Power** *(cont.)*	**Lake Turkana Wind Power** *(cont.)*	**Ormat Olkaria III Geothermal Power Plant, OrPower4 (phases 1, 2, and 3)** *(cont.)*
Foreign shareholder equity (entity, US$, millions)			Finnfund, IFU, Norfund	
DFI agency and financing method		About three-quarters of the 80€ million project will be debt financed. IFC, OFID, and Standard Bank Group Ltd. are each lending €20 million ($26 million). There are $32 million in equity investments and $76 million in long-term debt financing. The debt portion consists of an IFC A Loan, and commercial lending through an IFC B Loan and OFID.	*Senior debt:* AfDB, €115 million; Tranche 'B' ECA Facility funded €20 million; Tranche 'B' ECA Facility covered €100 million; EIB Senior Loan 'A,' €50 million; EIB Senior Loan 'B,' €50 million; FMO, €35 million; Proparco, €20 million; ICCF, €30 million *Mezzanine*: DEG, €20 million; EADB, €5 million; PTA, €10 million; AfDB, €2 million *Equity*: IFU, €7.5 million; Norfund, €16 million; Finnfund, €16 million	
Total DFI financing (US$, millions)	—	52.0	595.8	—
ODA grants (US$, millions)	—	—	—	—
Local credit enhancements and security arrangements			Government of Kenya letter of support	
Foreign credit enhancements and security arrangements		IDA guarantee, MIGA	EKF (Danish export credit agency) to guarantee approximately DKr 1 billion to EIB and AfDB	

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; AIIF2 = African Infrastructure Investment Fund 2; DEG = German Investment and Development Corporation; DFI = development finance institution; DKr = Danish kroner; EADB = East African Development Bank; ECA = Excess Crude Account; EIB = European Investment Bank; EKF = Eksport Kredit Fonden; FMO = Netherlands Development Finance Company; HFO = heavy fuel oil; ICCF = Interact Climate Change Facility; IDA = International Development Association; IFC = International Finance Corporation; IFU = Danish Investment Fund for Developing Countries; IPP = independent power project; MIGA = Multilateral Investment Guarantee Agency; MSD = medium-speed diesel; MW = megawatt; ODA = official development assistance; OFID = OPEC Fund for International Development; PTA = Preferential Trade Area Bank; REFiT = renewable energy feed-in tariff. In "Total DFI financing" and "ODA grants" cells "—" indicates 0 financing or grants, respectively.

Table E.8 IPP Investments in Madagascar, by Project

Project information	*Project name*
	Hydelec Madagascar S.A.
Capacity (MW)	15
Technology	Hydro, small (<50 MW)
Total investment (US$, millions)	17.8
Year of financial close	2007
Commercial operation date	2008
Project status	Operational
Procurement method	
Number of bids	
Contract period (years)	15
Contract type	Build-operate-transfer
Sponsors/developer	Hydelec Madagascar (100%, Madagascar)
Engineering, procurement, and construction	
Fuel arrangement	
Debt-equity ratio	
Local shareholder equity (entity, US$, millions)	
Foreign shareholder equity (entity, US$, millions)	
DFI agency and financing method	AfDB (loan, $9 million, 2007), MIGA (guarantee, $20 million, 2008)
Total DFI financing (US$, millions)	9.0
ODA grants (US$, millions)	
Local credit enhancements and security arrangements	
Foreign credit enhancements and security arrangements	

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; DFI = development finance institution; IPP = independent power project; MIGA = Multilateral Investment Guarantee Agency; MW = megawatt; ODA = official development assistance.

Table E.9 IPP Investments in Mauritius, by Project

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*	*Project name 6*
	Deep River Beau Champ, aka Consolidated Energy Ltd.	**FUEL Power Plant**	**Belle Vue Power Plant**	**St. Aubin Power Project, aka Compagnie Thermique du Sud**	**Compagnie Thermique de Savannah**	**Medine**
Capacity (MW)	28.4	36.7	71.2	32.5	90	13
Technology	Waste/bagasse	Waste/bagasse	Coal/bagasse	Waste/bagasse	OCGT/CCGT	Waste/bagasse
Total investment (US$, millions)	85.0	109.7	109.3	95.2	81.5	38.9
Year of financial close	1997	1998	1998	2004	2005	1994–2011
Commercial operation date						
Project status	Operational	Operational	Operational	Operational	Operational	Operational
Procurement method				International competitive bid		
Number of bids						
Contract period (years)		20	20	20		
Contract type	Build-own-operate	Build-own-operate	Build-own-operate	Build-own-operate		
Sponsors/developer	Sugar Investment Trust (10%, Mauritius)	Sugar Investment Trust (20%, Mauritius)	Harel Freres (51%, Mauritius), Sugar Investment Trust (14%, Mauritius), SIDEC (27%, France)	Sugar Investment Trust (15%, Mauritius), Mon Tresor Mon Desert (19%, Mauritius), Savannah Sugar Estates (15%, Mauritius), Societe Union St. Aubin (15%, Mauritius), Sechilienne-SIDEC (25%, France)		

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Table E.9 IPP Investments in Mauritius, by Project *(continued)*

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*	*Project name 6*
Engineering, procurement, and construction						
Fuel arrangement						
Debt-equity ratio						
Local shareholder equity (entity, US$, millions)						
Foreign shareholder equity (entity, US$, millions)						
DFI agency and financing method			EIB (loan, $17 million, 1998)			
Total DFI financing (US$, millions)	—	—	17.0	—	—	—
ODA grants (US$, millions)						
Local credit enhancements and security arrangements						
Foreign credit enhancements and security arrangements						

Note: Empty cells indicate that no information was available. CCGT = combined-cycle gas turbine; DFI = development finance institution; EIB = European Investment Bank; IPP = independent power project; MW = megawatt; OCGT = open-cycle gas turbine; ODA = official development assistance. In "Total DFI financing" cells "—" indicates 0 financing.

Table E.10 IPP Investments in Nigeria, by Project

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*
	AES Nigeria Barge Limited	**Okpai Independent Power Project**	**Afam Power Project**	**Azura**	**Aba Integrated (embedded)**
Capacity (MW)	270	480	630	450	141
Technology	OCGT/CCGT	OCGT/CCGT	OCGT/CCGT	OCGT	OCGT
Total investment (US$, millions)	240.0	462.0	540.0	895.0	460.0
Year of financial close	2001	2002	2008	2015	2013
Commercial operation date	2001	2005	2008	2016	2013
Project status	Operational	Operational	Operational	Financial close expected	Operational
Procurement method	Direct negotiation	Unsolicited proposals	Direct negotiation	Direct negotiation	Direct negotiation
Number of bids		1		8	
Contract period (years)	13	20	20	20	
Contract type	Build-own-operate	Build-own-operate	Build-own-operate	Build-own-operate	
Sponsors/developer	Enron (100%, United States), sold to AES (95%) and YFP (5%, Nigeria) in 2000	Nigerian National Petroleum Corporation (60%, Nigeria), Nigerian Agip Oil Company (20%, Italy, with Agip owned by ENI since 2003), and Phillips Oil Company (20%, United States) have maintained equity since 2001.	NNPC (55%, Nigeria), Shell (30%, United Kingdom/ Netherlands), Elf (Total) (10%, France), Agip (5%, Italy)	Aldwych International, AIIF, and ARM in conjunction with the government of Edo State, which has about 5% equity stake in the project.	Geometric
Engineering, procurement, and construction				Siemens and Julius Berger Nigeria	General Electric
Fuel arrangement	Utility arranges fuel.	Project company provides fuel.	Project company provides fuel.	15-year fuel supply agreement with Seplat with a gas supply letter of credit	Fuel supply agreement with Shell
Debt-equity ratio		0/100	0/100	80/20	
Local shareholder equity (entity, US$, millions)	5%			Main equity sponsors: Azura-Edo Ltd., 97.5%, comprising APHL, 50% (Amaya Capital, 80%; American Capital, 20%); AIM Energy Group, 30%; ARM, 6%; Aldwych, 14%; Edo State, 2.5%	

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Table E.10 IPP Investments in Nigeria, by Project *(continued)*

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*
Foreign shareholder equity (entity, US$, millions)		20%	0.45	Main equity sponsors: Azura-Edo Ltd., 97.5%, comprising APHL, 50% (Amaya Capital, 80%; American Capital, 20%); AIM, 30%; ARM, 6%; Aldwych, 14%; Edo State, 2.5%	
DFI agency and financing method	The $120 million in financing was funded from a consortium of four commercial banks and three DFIs. The DFIs are FMO, African Export-Import Bank, and DEG. The commercial banks are the Africa Merchant Bank (France), a division of Belgolaise Bank; United Bank for Africa (Nigeria); Rand Merchant Bank (South Africa); and Diamond Bank (Nigeria).			KfW Bankengruppe of Germany, FMO, IFC, DEG, French Investment Corporation, EAIF, World Bank Group, Swedfund, OPIC	Subordinated debt: IFC, EIB, and EAIF; equity: IFC, $4 million
Total DFI financing (US$, millions)	60.0	—	—	332.5	4.0
ODA grants (US$, millions)					
Local credit enhancements and security arrangements	Sovereign guarantee, $60 million letter of credit from Ministry of Finance	PPA backed by oil revenues of Nigerian Petroleum Development Company	PPA backed by oil revenues of Nigerian Petroleum Development Company		
Foreign credit enhancements and security arrangements	OPIC political risk insurance			Credit enhancement partial risk guarantees (IBRD)	

Note: Empty cells indicate that no information was available. AIIF = African Infrastructure Investment Fund; APHL = Azura Power Holding Limited; ARM = Asset and Resource Management; CCGT = combined-cycle gas turbine; DEG = German Investment and Development Corporation; DFI = development finance institution; EAIF = Emerging Africa Infrastructure Fund; EIB = European Investment Bank; FMO = Netherlands Development Finance Company; IBRD = International Bank for Reconstruction and Development; IFC = International Finance Corporation; IPP = independent power project; MW = megawatt; NNPC = Nigerian National Petroleum Corporation; OCGT = open-cycle gas turbine; ODA = official development assistance; OPIC = Overseas Private Investment Corporation; PPA = power purchase agreement; YFP = Yinka Folawiyo Power. In "Total DFI financing" cells "—" indicates 0 financing.

Table E.11 IPP Investments in Rwanda, by Project

Project information	*Project name*
	KivuWatt
Capacity (MW)	100
Technology	Methane gas
Total investment (US$, millions)	200.0
Year of financial close	2011
Commercial operation date	2015
Project status	Construction
Procurement method	Direct negotiation
Number of bids	
Contract period (years)	25
Contract type	Build-own-operate
Sponsors/developer	ContourGlobal (100%, United States)
Engineering, procurement, and construction	
Fuel arrangement	
Debt-equity ratio	
Local shareholder equity (entity, US$, millions)	
Foreign shareholder equity (entity, US$, millions)	
DFI agency and financing method	MIGA (guarantee, $26 million, 2011), AfDB (loan, $25 million, 2011). U.K., Dutch, Swedish, and Swiss governments loaned $91 million.
Total DFI financing (US$, millions)	116.0
ODA grants (US$, millions)	—
Local credit enhancements and security arrangements	
Foreign credit enhancements and security arrangements	

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; DFI = development finance institution; IPP = independent power project; MIGA = Multilateral Investment Guarantee Agency; MW = megawatt; ODA = official development assistance. In "ODA grants" cell "—" indicates 0 grants.

Table E.12 IPP Investments in Senegal, by Project

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*
	GTi Dakar Ltd.	**Kounoune I IPP**	**Saint-Louis-Dagana-Podor Rural Electrification**	**Sendou**	**Tobene**
Capacity (MW)	52	67.5	19	125	87.5
Technology	OCGT + CCGT	MSD/HFO	Solar, PV	Coal	MSD/HFO
Total investment (US$, millions)	65.0	110.0	22.0	254.3	163.5
Year of financial close	1997	2005	2010	2013	2014
Commercial operation date	2000	2008		2017	2015
Project status	Operational	Operational	Operational	Construction	Construction
Procurement method	International competitive bid	International competitive bid	International competitive bid	International competitive bid	International competitive bid, then direct negotiation
Number of bids			2		1
Contract period (years)	15	15	25		
Contract type	Build-own-operate-transfer	Build-own-operate	Build-operate-transfer		
Sponsors/developer	IFC, Sondel (Greenwich Air Service Inc.)	Melec PowerGen (part of Matelec Group, Lebanon), Mitsubishi (Japan)	Office National de l'Electricite (73%, Morocco), IFC (17%)		
Engineering, procurement, and construction	MEGS, a joint venture between Sondel and General Electric	MHI Equipment Europe, France (member, Mitsubishi Heavy Industries Group)			
Fuel arrangement		During the project negotiations, the structure of the FSA and purchase power agreement (PPA) were changed to turn the PPA into a tolling agreement.			
Debt-equity ratio		70/30			
Local shareholder equity (entity, US$, millions)					

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Table E.12 IPP Investments in Senegal, by Project *(continued)*

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*
	GTi Dakar Ltd. *(cont.)*	**Kounoune I IPP** *(cont.)*	**Saint-Louis-Dagana-Podor Rural Electrification** *(cont.)*	**Sendou** *(cont.)*	**Tobene** *(cont.)*
Foreign shareholder equity (entity, US$, millions)					
DFI agency and financing method	IFC (loan, $13 million, 1997), IFC (equity, $2 million, 1997), IFC (syndication, $3 million, 1997), IFC (equity, $1 million, 1998), IFC (syndication, $12 million, 1998), IFC (quasi-equity, $7 million, 1998), IFC (risk management, $1 million, 2002)	IDA (guarantee, $7 million, 2005), IDA (loan, $10 million, 2005), IFC (loan, $21 million, 2005).	IFC (equity, $1 million, 2010)	AfDB, FMO	IFC lead arranger, Euro tranche = €78.5 million – €28.5 million A Loan by IFC, and €50 million B Loan (€25 million by FMO and €25 million by EAIF), and a local tranche for the CFA equivalent of €13.5 million by BOAD
Total DFI financing (US$, millions)	39.0	53.7	1.0	108.0	135.1
ODA grants (US$, millions)					
Local credit enhancements and security arrangements	Government guarantee, escrow account	Government guarantee, a letter of credit from SENELEC			
Foreign credit enhancements and security arrangements	Credit insurance through a guarantee program of SACE, the Italian export credit agency, and a partial interest subsidy through the Mediocredito Central Subsidy Department (MCSD)	A partial risk guarantee, but never signed by government			IDA partial risk guarantee

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; BOAD = West African Development Bank; CBAO = Banking Company of West Africa; CCGT = combined-cycle gas turbine; DFI = development finance institution; EAIF = Emerging Africa Infrastructure Fund; FMO = Netherlands Development Finance Company; FSA = Fuel Supply Agreement; HFO = heavy fuel oil; IDA = International Development Association; IFC = International Finance Corporation; IPP = independent power project; MEGS = Mediterranean Electric Generating Services; MHI = Manitoba Hydro International; MSD = medium-speed diesel; MW = megawatt; OCGT = open-cycle gas turbine; ODA = official development assistance; PV = photovoltaic; SENELEC = Société Nationale d'Électricité du Sénégal.

Table E.13 IPP Investments in Sierra Leone, by Project

Project information	*Project name*
	Addax Biomass Plant
Capacity (MW)	15
Technology	Biomass
Total investment (US$, millions)	30
Year of financial close	2011
Commercial operation date	2013
Project status	Operational
Procurement method	Direct negotiation
Number of bids	
Contract period (years)	
Contract type	Build-own-operate
Sponsors/developer	Addax & Oryx Group (100%, United Kingdom)
Engineering, procurement, and construction	
Fuel arrangement	
Debt-equity ratio	61/39
Local shareholder equity (entity, US$, millions)	
Foreign shareholder equity (entity, US$, millions)	
DFI agency and financing method	AfDB (loan, $30 million, 2011)
Total DFI financing (US$, millions)	30
ODA grants (US$, millions)	
Local credit enhancements and security arrangements	
Foreign credit enhancements and security arrangements	

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; DFI = development finance institution; IPP = independent power project; MW = megawatt; ODA = official development assistance.

Table E.14 IPP Investments in Tanzania, by Project

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*
	Independent Power Tanzania Ltd.	**Songas-Songo Songo Gas-to-Power Project**	**Mtwara Region Gas-to-Power Project**	**Symbion**
Capacity (MW)	100	189	18	120
Technology	MSD/HFO	CCGT	OCGT/CCGT	OCGT/CCGT
Total investment (US$, millions)	127.2	316.0	32.0	123.2
Year of financial close	1997	2001	2005	2006
Commercial operation date	2002	2004	2007	2006, 2007
Project status	Operational	Operational	Operational	Operational
Procurement method	Direct negotiation	International competitive bid	International competitive bid	Direct negotiation
Number of bids		2		
Contract period (years)	20	20	25	Expiry Oct. 2014
Contract type	Build-own-operate	Build-own-operate	Build-own-operate	Emergency/short-term
Sponsors/developer	VIP Engineering and Marketing Ltd. (Tanzania), MechMar Energy Sdn Bhd	TransCanada sold majority shares to AES (United States) in 1999 and AES sold majority shares to Globeleq (United Kingdom) in 2003. All preferred equity shares were converted into "Loan Notes" in June 2009. Only common shares remain.	Artumas Group Inc. (87%, Canada), FMO (13%)	Built by Richmond, sold to Dowans, then to Symbion
Engineering, procurement, and construction		Larsen and Toubro (L&T)		
Fuel arrangement	IPTL imports fuel, which is a pass-through to the utility.	Songo Songo gas is provided to project company at a rate of $0.55/MMBtu for turbines I–V and at $2.17/MMBtu for turbine VI.	Fuel is provided by a consortium that includes the project sponsor (has a 25.4% stake in the gas concession), at a charge of $5.00/MMBtu, which is passed through to utility.	TANESCO purchases natural gas, and fuel is a pass-through.
Debt-equity ratio	0/100	70/30	0/100	0/100

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Table E.14 IPP Investments in Tanzania, by Project *(continued)*

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*
Local shareholder equity (entity, US$, millions)	VIP (30% in kind, Tanzania—disputed) has sought to sell shares.	4.83	100% financed with balance sheet of shareholders	
Foreign shareholder equity (entity, US$, millions)	Mechmar (70%, Malaysia) has sought to sell shares.	5.67	100% financed with balance sheet of shareholders	Equity financed
DFI agency and financing method		IBRD (loan, $183 million, 2001), EIB (loan, $55 million, 2001)	FMO, 13% equity shareholder	
Total DFI financing (US$, millions)	—	249.0	4.2	—
ODA grants (US$, millions)	—	100.3	—	—
Local credit enhancements and security arrangements	Sovereign guarantee, liquidity facility equivalent to four months of capacity charge (but not yet established)	Escrow account: for first 115 MW, with the government matching every $1 spent by the project company; liquidity facility equivalent to four months of capacity charge for the first three years, declining to two months starting in year four through the remaining years of the contract	Tariff Equalization Fund provided a fixed-value account designed to make up the difference between the national tariff and the cost-based tariff (which would otherwise be charged to the final consumer) under the project.	No government guarantees
Foreign credit enhancements and security arrangements				

Note: Empty cells indicate that no information was available. CCGT = combined-cycle gas turbine; DFI = development finance institution; EIB = European Investment Bank; FMO = Netherlands Development Finance Company; HFO = heavy fuel oil; IBRD = International Bank for Reconstruction and Development; IPP = independent power project; IPTL = Independent Power Tanzania Ltd.; MMBtu = million British thermal units; MSD = medium-speed diesel; MW = megawatt; OCGT = open-cycle gas turbine; ODA = official development assistance; TANESCO = Tanzania Electric Supply Company. In "Total DFI financing" and "ODA grants" cells "—" indicates 0 financing or grants, respectively.

Table E.15 IPP Investments in Togo, by Project

Project information	*Project name*
	Centrale Thermique de Lomé
Capacity (MW)	100
Technology	Triple fuel
Total investment (US$, millions)	196.0
Year of financial close	2008
Commercial operation date	2010
Project status	Operational
Procurement method	Direct negotiation
Number of bids	
Contract period (years)	25
Contract type	Build-operate-transfer
Sponsors/developer	ContourGlobal (80%, United States), IFC (20%)
Engineering, procurement, and construction	
Fuel arrangement	
Debt-equity ratio	
Local shareholder equity (entity, US$, millions)	
Foreign shareholder equity (entity, US$, millions)	
DFI agency and financing method	IFC (equity/loan) and OPIC
Total DFI financing (US$, millions)	161.0
ODA grants (US$, millions)	
Local credit enhancements and security arrangements	Payment guarantee
Foreign credit enhancements and security arrangements	

Note: Empty cells indicate that no information was available. DFI = development finance institution; IFC = International Finance Corporation; IPP = independent power project; MW = megawatt; ODA = official development assistance; OPIC = Overseas Private Investment Corporation.

Table E.16A IPP Investments in Uganda, by Project

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*	*Project name 6*
	Kasese Cobalt (Mubuku III)	**Kilembe Mines (Mubuku I)**	**Kakira Cogeneration Plant**	**Bujagali Hydro Project**	**ECO Ishasha Mini Hydropower Plant**	**Tronder/Bugoye Hydro Electric Power Project (Mubuku II)**
Capacity (MW)	9.9	5.4	32	250	6.5	13
Technology	Hydro, small (<20 MW)	Hydro, small (<20 MW)	Waste/bagasse	Hydro	Hydro, small (<20 MW)	Hydro, small (<20 MW)
Total investment (US$, millions)	22.5	16.2	56.0	860.0	14.0	65.7
Year of financial close	1999	1975	2003	2007	2008	2008
Commercial operation date			2013	2012	2011	2009
Project status	Operational	Not operational	Operational	Operational	Operational	Operational
Procurement method	Direct negotiation		Direct negotiation/ REFiT (PPA3)	International competitive bid	Direct negotiation	Direct negotiation
Number of bids				3		
Contract period (years)	20		20	30	30	20
Contract type			Build-own-operate	Build-operate-transfer	Build-operate-transfer	Build-operate-transfer
Sponsors/developer	Blue Earth Refineries Inc. (100%, Uganda)	Government of Uganda (51%)	Madhvani Group (100%, Uganda)	BEL Ltd. (Sithe Global Power) (58%, United States), Aga Khan Fund (31%, Switzerland)	Eco Power (100%, Sri Lanka)	Tronder Power Ltd. (100%, Norway)
Engineering, procurement, and construction			In-house/consultant			
Fuel arrangement						
Debt-equity ratio				78/22	70/30	53/32 (14% grant by government of Norway)
Local shareholder equity (entity, US$, millions)			Nonrecourse			Tronder

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Table E.16A IPP Investments in Uganda, by Project *(continued)*

Project information	*Project name 1*	*Project name 2*	*Project name 3*	*Project name 4*	*Project name 5*	*Project name 6*
	Kasese Cobalt (Mubuku III) *(cont.)*	**Kilembe Mines (Mubuku I)** *(cont.)*	**Kakira Cogeneration Plant** *(cont.)*	**Bujagali Hydro Project** *(cont.)*	**ECO Ishasha Mini Hydropower Plant** *(cont.)*	**Tronder/Bugoye Hydro Electric Power Project (Mubuku II)** *(cont.)*
Foreign shareholder equity (entity, US$, millions)			Balance sheet			Norfund
DFI agency and financing method			EADB	MIGA (guarantee, $115 million, 2007), IFC (loan, $130 million, 2007), IDA (guarantee, $115 million, 2007), AfDB (loan, $110 million, 2007), EIB (loan, $130 million, 2007)		EAIF/FMO/government of Norway/Norfund
Total DFI financing (US$, millions)	—	—	15.0	370.0	—	48.2
ODA grants (US$, millions)			GETFiT			14% grant by government of Norway
Local credit enhancements and security arrangements				Government payment guarantee		Government payment guarantee
Foreign credit enhancements and security arrangements						

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; DFI = development finance institution; EADB = East African Development Bank; EAIF = Emerging Africa Infrastructure Fund; EIB = European Investment Bank; FMO = Netherlands Development Finance Company; GETFiT = global energy transfer feed-in tariff; IDA = International Development Association; IFC = International Finance Corporation; IPP = independent power project; MIGA = Multilateral Investment Guarantee Agency; MW = megawatt; ODA = official development assistance; PPA = power purchase agreement; REFiT = renewable energy feed-in tariff. In "Total DFI financing" cells "—" indicates 0 financing.

Table E.16B IPP Investments in Uganda, by Project

Project information	*Project name 7*	*Project name 8*	*Project name 9*	*Project name 10*	*Project name 11*	*Project name 12*
	Mpanga Hydro Power Project	**Namanve Power Plant**	**Kinyara Cogeneration Plant**	**Buseruka/Hydromax Hydropower Plant**	**Tororo Power Station**	**Tororo Power Station**
Capacity (MW)	18	50	7.5	9	16	34
Technology	Hydro, small (<20 MW)	MSD/HFO	Waste/bagasse	Hydro, small (<20 MW)	MSD/HFO	MSD/HFO
Total investment (US$, millions)	27.0	74.0	29.0	27.0	41.5	41.5
Year of financial close	2008	2008	2009	2009	2009	2012
Commercial operation date	2011		2011	2012	2010	
Project status	Operational	Operational	Operational	Operational	Operational	Operational
Procurement method	Direct negotiation	International competitive bid	Direct negotiation	Direct negotiation	Direct negotiation	
Number of bids		3				
Contract period (years)	20	6	20	30	9	
Contract type	Build-operate-transfer	Build-operate-transfer	Build-operate-own	Build-operate-transfer	Build-operate-own	
Sponsors/developer	SAEMS (100%, United States)	Jacobsen Elektro (100%, Norway)	Kinyara Sugar Group (100%, Uganda)	Hydromax Limited (100%, Uganda)	Electro-Maxx (100%, Uganda)	
Engineering, procurement, and construction						
Fuel arrangement						
Debt-equity ratio				70/30	60/40	
Local shareholder equity (entity, US$, millions)						
Foreign shareholder equity (entity, US$, millions)						
DFI agency and financing method	EAIF ($14 million), FMO			AfDB (loan, $9 million, 2009)		
Total DFI financing (US$, millions)	20.0	—	—	9.0	—	—
ODA grants (US$, millions)						
Local credit enhancements and security arrangements	Payment guarantee	Payment guarantee		Variable government payments	Government payment guarantee	
Foreign credit enhancements and security arrangements						

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; DFI = development finance institution; EAIF = Emerging Africa Infrastructure Fund; FMO = Netherlands Development Finance Company; HFO = heavy fuel oil; IPP = independent power project; MSD = medium-speed diesel; MW = megawatt; ODA = official development assistance; SAEMS = South Asia Energy Management Systems. In "Total DFI financing" cells "—" indicates 0 financing.

Table E.16C IPP Investments in Uganda, by Project

Project information	*Project name 13*	*Project name 14*	*Project name 15*	*Project name 16*	*Project name 17*	*Project name 18*
	Kakaka Hydropower Project	**Rwimi Hydropower Project**	**Lubilia Hydropower Project**	**Muvumbe Hydropower Project**	**Nengo Bridge Hydropower Project**	**SAIL Cogen**
Capacity (MW)	5	5.4	5.4	6.5	6.9	6.9
Technology	Hydro, small (<20 MW)	Hydro, small (<20 MW)	Hydro, small (<20 MW)	Hydro, small (<20 MW)	Hydro, small (<20 MW)	Waste/bagasse
Total investment (US$, millions)	18.0	18.0	18.0	14.0	27.0	22.0
Year of financial close	2015	2015	2015	2015	2015	2015
Commercial operation date	2016	2016	2016	2016	2016	2015
Project status	Financing in process	Financing in process	Financing in process	Financing in process	Financing in process	Construction finished, not interconnected
Procurement method	REFiT	REFiT	REFiT	REFiT	REFiT	REFiT
Number of bids						
Contract period (years)	20	20	20	20	20	20
Contract type	Build-operate-transfer	Build-operate-transfer	Build-operate-transfer	Build-operate-transfer	Build-operate-transfer	Build-own-operate
Sponsors/developer	Frontier (Danish private equity fund)	Eco Power (100%, Sri Lanka)	Frontier (Danish private equity fund)	Vidullanka (100%, Sri Lanka)	Jacobsen Elektro (100%, Norway)	Sugar Allied Industries (Uganda)
Engineering, procurement, and construction						
Fuel arrangement						
Debt-equity ratio		70/30	65/35			
Local shareholder equity (entity, US$, millions)						
Foreign shareholder equity (entity, US$, millions)						
DFI agency and financing method	EAIF, FMO		EAIF, FMO		EADB	
Total DFI financing (US$, millions)	—	—	—	—	—	—
ODA grants (US$, millions)		GETFiT	GETFiT	GETFiT	GETFiT	GETFiT
Local credit enhancements and security arrangements						
Foreign credit enhancements and security arrangements						

Note: Empty cells indicate that no information was available. DFI = development finance institution; EADB = East African Development Bank; EAIF = Emerging Africa Infrastructure Fund; FMO = Netherlands Development Finance Company; GETFiT = global energy transfer feed-in tariff; IPP = independent power project; MW = megawatt; ODA = official development assistance; REFiT = renewable energy feed-in tariff. In "Total DFI financing" cells "—" indicates 0 financing.

Table E.16D IPP Investments in Uganda, by Project

Project information	*Project name 19*	*Project name 20*	*Project name 21*	*Project name 22*
	SAEMS Nyamwamba SHPP	**Siti I/II Hydropower Project**	**Tororo North/South**	**Tororo North/South**
Capacity (MW)	9.2	21.5	10	10
Technology	Hydro, small (<20 MW)	Hydro, large	Solar PV	Solar PV
Total investment (US$, millions)	34.0	48.0	18.0	18.0
Year of financial close	2015	2015	2015	2015
Commercial operation date	2016	2016–17		
Project status	Construction started in 2014	Financing in process	Financing in process	Financing in process
Procurement method	REFiT	REFiT	International competitive bid	International competitive bid
Number of bids				
Contract period (years)	20	20		
Contract type	Build-operate-transfer	Build-operate-transfer		
Sponsors/developer	SAEMS (100%, United States)	Frontier (Danish private equity fund)	Simba/Building Energy	Access/TSK
Engineering, procurement, and construction				
Fuel arrangement				
Debt-equity ratio	73/27	70/30	75/25	75/25
Local shareholder equity (entity, US$, millions)				
Foreign shareholder equity (entity, US$, millions)				
DFI agency and financing method	Other (loan, $24 million, 2012) of which EAIF accounts for $6 million	EAIF, FMO ($5.3 million)	FMO	FMO
Total DFI financing (US$, millions)	6.0	5.3	—	—
ODA grants (US$, millions)	GETFiT	GETFiT		
Local credit enhancements and security arrangements				
Foreign credit enhancements and security arrangements				

Note: Empty cells indicate that no information was available. DFI = development finance institution; EAIF = Emerging Africa Infrastructure Fund; FMO = Netherlands Development Finance Company; IPP = independent power project; MW = megawatt; ODA = official development assistance; PV = photovoltaic; REFiT = renewable energy feed-in tariff; SAEMS = South Asia Energy Management Systems; SHPP = small hydropower project. In "Total DFI financing" cells "—" indicates 0 financing.

Table E.17 IPP Investments in Zambia, by Project

Project information	*Project name 1*	*Project name 2*
	Ndola Energy	**Tata Itezhi-Tezhi Hydropower Plant**
Capacity (MW)	50	120
Technology	MSD/HFO	Hydro
Total investment (US$, millions)	72.0	230.0
Year of financial close	2012	2014
Commercial operation date	2013	2016
Project status	Operational	Construction
Procurement method	Direct negotiation	Direct negotiation
Number of bids		
Contract period (years)		25
Contract type		Build-operate-transfer
Sponsors/developer	Subsidiary of Concordia Energy (Group of Mauritius)	Tata Enterprises (50%, India), ZESCO (50%, Zambia)
Engineering, procurement, and construction (EPC)		Chinese EPC/international competitive bid for EPC
Fuel arrangement		
Debt-equity ratio		
Local shareholder equity (entity, US$, millions)		
Foreign shareholder equity (entity, US$, millions)		
DFI agency and financing method		EIB (equity, $18 million, 2011); 2014: a $142 million loan by DBSA, Proparco, AfDB, and FMO
Total DFI financing (US$, millions)	—	162.0
ODA grants (US$, millions)		
Local credit enhancements and security arrangements		
Foreign credit enhancements and security arrangements		

Note: Empty cells indicate that no information was available. AfDB = African Development Bank; DBSA = Development Bank of Southern Africa; DFI = development finance institution; EIB = European Investment Bank; FMO = Netherlands Development Finance Company; HFO = heavy fuel oil; IPP = independent power project; MSD = medium-speed diesel; MW = megawatt; ODA = official development assistance; ZESCO = Zambia Electricity Supply Corporation. In "Total DFI financing" cell "—" indicates 0 financing.

Table E.18 IPP Investments in South Africa, by Project

Project	*Capacity (MW)*	*Technology*	*Total investment (US$, millions)*	*Financial close*	*Commercial operation date*	*Project status*	*Procurement method*	*Sponsors/ developer*	*DFI agency and financing method*	*Total DFI financing (US$, millions)*	*Local credit enhancements and security arrangements*
Bethlehem Hydro	7	Hydro, small (<20 MW)	13.7	2005	2009, 2012	Operational	DN	NuPlanet (26%, Netherlands)	Other (loan, $5 million, 2005)	5.0	
Darling Wind Farm	5	Wind, onshore	9.9	2006	2008	Operational	DN	Darling Independent Power Producer Pty Ltd. (26%, South Africa)		—	
Sasol	373	OCGT/CCGT	399.0	2010	2010	Operational	DN	Sasol		—	
SlimSun Swartland Solar Park	5	Solar, PV	26.1	2012	2013	Operational	ICB		IDC, in 2012 R (exchange rate, 0.12)	8.9	Payment guarantee
RustMo1 Solar Farm	6.9	Solar, PV	28.0	2012	2013	Operational	ICB		IDC, in 2012 R (exchange rate, 0.12)	9.8	Payment guarantee
Konkoonsies Solar Energy Facility	9.7	Solar, PV	43.9	2012	2013	Operational	ICB		IDC, in 2012 R (exchange rate, 0.12)	15.0	Payment guarantee
Aries Solar Energy Facility	9.7	Solar, PV	44.5	2012	2013	Operational	ICB		IDC, in 2012 R (exchange rate, 0.12)	15.0	Payment guarantee
Greefspan PV Power Plant	9.9	Solar, PV	53.5	2012	2014	Operational	ICB		IDC, in 2012 R (exchange rate, 0.12)	10.0	Payment guarantee
Mulilo Solar PV De Aar	10	Solar, PV	39.3	2012	2013	Operational	ICB		IDC, in 2012 R (exchange rate, 0.12)	13.6	Payment guarantee

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Table E.18 IPP Investments in South Africa, by Project *(continued)*

Project	*Capacity (MW)*	*Technology*	*Total investment (US$, millions)*	*Financial close*	*Commercial operation date*	*Project status*	*Procurement method*	*Sponsors/ developer*	*DFI agency and financing method*	*Total DFI financing (US$, millions)*	*Local credit enhancements and security arrangements*
Herbert PV Power Plant	20	Solar, PV	105.3	2012	2013	Operational	ICB		IDC, in 2012 R (exchange rate, 0.12)	12.8	Payment guarantee
Mulilo Solar PV Prieska	20	Solar, PV	79.1	2012	2015	Operational	ICB		IDC, in 2012 R (exchange rate, 0.12)	26.9	Payment guarantee
Dassieklip Wind Energy Facility	27	Wind, onshore	83.1	2012	2014	Operational	ICB		IDC, in 2012 R (exchange rate, 0.12)	18.0	Payment guarantee
MetroWind Van Stadens Wind Farm	27	Wind, onshore	74.8	2012	2014	Operational	ICB			—	Payment guarantee
Soutpan Solar Park	28	Solar, PV	155.7	2012	2014	Operational	ICB			—	Payment guarantee
Witkop Solar Park	30	Solar, PV	174.3	2012	2014	Operational	ICB			—	Payment guarantee
Touwsrivier Solar Park	36	Solar, PV	197.5	2012	2014	Operational	ICB			—	Payment guarantee
De Aar Solar PV	45.6	Solar, PV	178.0	2012	2014	Operational	ICB	Globeleq	DBSA, in 2012 R (exchange rate, 0.12)	43.0	Payment guarantee
South Africa Mainstream Renewable Power Droogfontein	45.6	Solar, PV	173.6	2012	2014	Operational	ICB	Globeleq	DBSA, in 2012 R (exchange rate, 0.12)	41.9	Payment guarantee

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Table E.18 IPP Investments in South Africa, by Project *(continued)*

Project	*Capacity (MW)*	*Technology*	*Total investment (US$, millions)*	*Finan-cial close*	*Com-mercial operation date*	*Project status*	*Procure-ment method*	*Sponsors/ developer*	*DFI agency and financing method*	*Total DFI financing (US$, millions)*	*Local credit enhance-ments and security arrangements*
Khi Solar One	50	Solar, CS	509.8	2012		Construction	ICB		IFC, EIB, DBSA, and IDC all have debt; IDC also has 29% equity.	298.7	Payment guarantee
Letsatsi Solar Photovoltaic Park	64	Solar, PV	320.9	2012	2014	Operational	ICB			—	Payment guarantee
Lesedi Solar Photovoltaic Park	64	Solar, PV	322.7	2012	2014	Operational	ICB			—	Payment guarantee
Hopefield Wind Farm	65.4	Wind, onshore	195.6	2012	2014	Operational	ICB			—	Payment guarantee
Kalkbult	72.5	Solar, PV	274.9	2012	2013	Operational	ICB		DBSA, in 2012 R (exchange rate, 0.12)	29.8	Payment guarantee
Kathu Solar Plant	75	Solar, PV	430.4	2012	2014	Operational	ICB		DBSA, in 2012 R (exchange rate, 0.12)	45.0	Payment guarantee
Solar Capital De Aar	75	Solar, PV	296.6	2012	2014	Operational	ICB			—	Payment guarantee
Noblesfontein Phase 1	75	Wind, onshore	196.8	2012	2014	Operational	ICB			—	Payment guarantee
Kouga Wind Farm	80	Wind, onshore	235.6	2012	2014	Operational	ICB		IDC, in 2012 R (exchange rate, 0.12)	53.9	Payment guarantee

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Table E.18 IPP Investments in South Africa, by Project *(continued)*

Project	*Capacity (MW)*	*Technology*	*Total investment (US$, millions)*	*Financial close*	*Commercial operation date*	*Project status*	*Procurement method*	*Sponsors/ developer*	*DFI agency and financing method*	*Total DFI financing (US$, millions)*	*Local credit enhancements and security arrangements*
Dorper Wind Farm	97.5	Wind, onshore	286.1	2012	2014	Operational	ICB			—	Payment guarantee
KaXu Solar One	100	Solar CS	976.3	2012	2014	Operational	ICB		DBSA, R 1.2 billion; IDC, R 830 million; IFC, R 600 million; IFC (as Implementation Entity of the Clean Technology Fund), R 232 million. *Mezzanine debt*: DBSA, R 195 million; IDC, R 195 million *Equity:* IDC, 29%	454.8	Payment guarantee
Jeffreys Bay	138	Wind, onshore	366.5	2012	2014	Operational	ICB	Globeleq	DBSA, R 849 million	101.8	Payment guarantee
Cookhouse Wind Farm	138.6	Wind, onshore	295.6	2012	2014	Operational	ICB			—	Payment guarantee
Vredendal Solar Park	8.82	Solar, PV	29.1	2013		Operational	ICB			—	Payment guarantee
Stortemelk Hydro Pty Ltd.	4.4	Hydro, small (<20 MW)	17.4	2013		Operational				—	Payment guarantee

table continues next page

Table E.18 IPP Investments in South Africa, by Project *(continued)*

Project	*Capacity (MW)*	*Technology*	*Total investment (US$, millions)*	*Finan-cial close*	*Com-mercial operation date*	*Project status*	*Procure-ment method*	*Sponsors/ developer*	*DFI agency and financing method*	*Total DFI financing (US$, millions)*	*Local credit enhance-ments and security arrangements*
Upington Solar PV	8.9	Solar, PV	26.5	2013		Operational	ICB			—	Payment guarantee
Aurora-Rietvlei Solar Power	9	Solar, PV	30.3	2013		Operational	ICB			—	Payment guarantee
Neusberg Hydro Electric Project A	10	Hydro, small (<20 MW)	73.5	2013		Operational	ICB		IDC, in 2013 R (exchange rate, 0.12), senior and mezzanine debt	19.7	Payment guarantee
Chaba Wind Farm Project	21	Wind, onshore	54.4	2013		Operational	ICB		IDC, in 2013 R (exchange rate, 0.12)	15.5	Payment guarantee
Waainek Wind Power	23.3	Wind, onshore	69.7	2013		Construction	ICB		IDC, in 2013 R (exchange rate, 0.12)	19.9	Payment guarantee
Linde	36.8	Solar, PV	147.2	2013		Operational	ICB			—	Payment guarantee
Bokpoort CSP Project	50	Solar CS	642.2	2013		Construction	ICB		IDC (25% equity)	45.1	Payment guarantee
Grassridge Wind Energy Project	59.8	Wind, onshore	161.3	2013		Operational	ICB		IDC, 2013	46.1	Payment guarantee
Boshof Solar Park	60	Solar, PV	312.0	2013		Operational	ICB		OPIC	222.7	Payment guarantee

table continues next page

Table E.18 IPP Investments in South Africa, by Project *(continued)*

Project	*Capacity (MW)*	*Technology*	*Total investment (US$, millions)*	*Finan-cial close*	*Com-mercial operation date*	*Project status*	*Procure-ment method*	*Sponsors/ developer*	*DFI agency and financing method*	*Total DFI financing (US$, millions)*	*Local credit enhance-ments and security arrangements*
Dreunberg	69.6	Solar, PV	286.6	2013		Operational	ICB			—	Payment guarantee
Sishen Solar Facility	74	Solar, PV	294.8	2013	2014	Operational	ICB			—	Payment guarantee
Solar Capital De Aar 3	75	Solar, PV	326.9	2013		Operational	ICB		IDC	111.1	Payment guarantee
Jasper Power Company	75	Solar, PV	290.7	2013		Operational	ICB		DBSA	60.0	Payment guarantee
West Coast One Wind Farm	90.8	Wind, onshore	252.1	2013		Operational	ICB		DBSA	44.1	Payment guarantee
Tsitsikamma Community Wind Farm	94.8	Wind, onshore	365.9	2013		Construction	ICB			—	Payment guarantee
Amakhala Emoyeni Wind Farm	133.7	Wind, onshore	497.0	2013		Construction	ICB		IFC	76.1	Payment guarantee
Gouda Wind Project	135.5	Wind, onshore	336.3	2013		Operational	ICB			—	Payment guarantee
Mkuze	16.5	Biomass	95.6	2015		Financing and approvals under way	ICB			—	Payment guarantee
Johannesburg Landfill Gas to Electricity	18	Landfill gas	24.8	2014		Partially opera-tional	ICB			—	Payment guarantee
Tom Burke Solar Park	60	Photovoltaic, thin film fixed		2014		Construction	ICB			—	Payment guarantee

table continues next page

Table E.18 IPP Investments in South Africa, by Project *(continued)*

Project	*Capacity (MW)*	*Technology*	*Total investment (US$, millions)*	*Financial close*	*Commercial operation date*	*Project status*	*Procurement method*	*Sponsors/ developer*	*DFI agency and financing method*	*Total DFI financing (US$, millions)*	*Local credit enhancements and security arrangements*
Adams Solar PV 2	75	Photovoltaic, crystalline fixed		2014		Construction	ICB			—	Payment guarantee
Electra Capital (Pty) Ltd.	75	Photovoltaic, crystalline fixed		2014		Construction	ICB			—	Payment guarantee
Mulilo Sonnedix Prieska PV	75	Photovoltaic, crystalline fixed	108.0	2014		Construction	ICB			—	Payment guarantee
Mulilo Prieska PV	75	Photovoltaic, crystalline single axis	200.0	2014		Construction	ICB		IDC, 2014	20.2	Payment guarantee
Pulida Solar Park	75	Photovoltaic, thin film fixed		2014		Financing done	ICB			—	Payment guarantee
Noupoort Mainstream Wind	80	Wind, onshore	180.0	2014		Construction	ICB		EKF and DBSA	108.5	Payment guarantee
Nojoli Wind Farm	86.6	Wind, onshore		2014		Financing done	ICB			—	Payment guarantee
Longyuan Mulilo De Aar Maanhaarberg Wind Energy Facility	96.5	Wind, onshore	180.0	2014		Financing done	ICB		IDC	63.0	Payment guarantee

table continues next page

Table E.18 IPP Investments in South Africa, by Project *(continued)*

Project	*Capacity (MW)*	*Technology*	*Total investment (US$, millions)*	*Finan-cial close*	*Com-mercial operation date*	*Project status*	*Procure-ment method*	*Sponsors/ developer*	*DFI agency and financing method*	*Total DFI financing (US$, millions)*	*Local credit enhance-ments and security arrangements*
Ilanga CSP 1/Karoshoek Solar One	100	Concentrated solar power, parabolic trough, with storage (4.5 hours per day)	735.4	2014		Construction	ICB		IDC and DBSA	180.0	Payment guarantee
Xina Solar One	100	Concentrated solar power, parabolic trough, with storage (5 hours per day)	880.0	2014		Construction	ICB		DBSA, R 800 million; IDC R 750 million; AfDB, R 1.5 billion; IDC, 20% equity	316.8	Payment guarantee
Red Cap–Gibson Bay	110	Wind, onshore	202.5	2014		Financing done	ICB			—	Payment guarantee
Khobab Wind Farm	137.7	Wind, onshore	315.0	2014		Construction	ICB		DBSA, EKF	214.2	Payment guarantee
Loeriesfontein 2 Wind Farm	138.2	Wind, onshore	315.0	2014		Construction	ICB		DBSA, EKF	208.5	Payment guarantee
Longyuan Mulilo De Aar 2 North Wind Energy Facility	139.0	Wind, onshore	264.6	2014		Financing done	ICB		IDC	85.5	Payment guarantee

Note: Empty cells indicate that no information was available. Renewable Energy Independent Power Project Procurement Programme (REIPPPP) investment data are derived from public sources and have an error range of about 10 percent. Final financial close data are different from bid data and are not yet publicly available. AfDB = African Development Bank; CCGT = combined-cycle gas turbine; CSP = concentrated solar power; DBSA = Development Bank of Southern Africa; DFI = development finance institution; DN = direct negotiation; EIB = European Investment Bank; EKF = Eksport Kredit Fonden (Danish export credit agency); ICB = international competitive bid; IDC = Industrial Development Corporation; IFC = International Finance Corporation; IPP = independent power project; MW = megawatt; OCGT = open-cycle gas turbine; OPIC = Overseas Private Investment Corporation; PV = photovoltaic; R = rand. In "Total DFI financing" cells "—" indicates 0 financing.

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green press INITIATIVE

Inadequate electricity services pose a major impediment to reducing extreme poverty and boosting shared prosperity in Sub-Saharan Africa. Simply put, Africa does not have enough power.

Despite the abundant low-carbon and low-cost energy resources available to Sub-Saharan Africa, the region's entire installed electricity capacity, at a little over 80 gigawatts (GW), is equivalent to that of the Republic of Korea. Looking ahead, Sub-Saharan Africa will need to ramp up its power generation capacity substantially. The investment needed to meet this goal largely exceeds African countries' already stretched public finances. Increasing private investment is critical to help expand and improve electricity supply.

Historically, most private sector finance has been channeled through privately financed independent power projects (IPPs), supported by nonrecourse or limited recourse loans, with long-term power purchase agreements with the state utility or another off-taker. Between 1990 and 2014, IPPs have spread across Sub-Saharan Africa and are now present in 18 countries. However, private investment could be much greater and less concentrated.

The objective of *Independent Power Projects in Sub-Saharan Africa: Lessons from Five Key Countries* is to evaluate the experience of IPPs and identify lessons that can help African countries attract more and better private investment. The analysis is based primarily on in-depth case studies carried out in five countries—Kenya, Nigeria, South Africa, Tanzania, and Uganda—that have the most extensive experience with IPPs.

At the core of this analysis is a reflection on whether IPPs have in fact benefited Sub-Saharan Africa, and how they might be improved.

ESMAP
Energy Sector Management Assistance Program

Africa Renewable Energy
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