EMERGENCE AND SUSTAINABILITY OF INDEPENDENT POWER PROJECTS IN NIGERIA

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ABSTRACT

Africa is short of power and the poor performance of its electricity utilities undermines sustainable development. Over the past two decades, power sector reforms across the continent have sought to restructure utilities and increase private sector participation and competition in an effort to improve technical and commercial efficiencies and attract more investment in generation capacity and widened access to electricity. These reforms have progressed further in Nigeria than elsewhere in Africa and, although they are still a work in progress, the country provides a fascinating case study on the merits of unbundling and private investment, and whether the potential benefits are sustainable. Will the next generation of independent power projects (IPPs) be successful and lead to further investment in much-needed power generation capacity? Will risks be mitigated? Will sector reforms foster financial sustainability? These are some of the questions that will be answered in this article.

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1. Introduction

AFRICA does not produce enough power for its needs and the poor performance of its electricity utilities undermines sustainable development. Over the past two decades, power sector reforms across the continent have sought to restructure utilities and increase private sector participation and competition in an effort to improve technical and commercial efficiencies, attract more investment in generation capacity and widen access to electricity.

These reforms have progressed further in Nigeria than elsewhere in Africa and, although they are still a work in progress, the country provides a fascinating case study on the merits of unbundling and private investment, and whether the potential benefits are sustainable.

While Nigeria has the largest population and economy on the African continent, half of its citizens live below the poverty line and do not have access to electricity. The demand for electricity far outweighs available capacity, which is often less than 5 gigawatts (GW) for a population of about 170 million. Compare this with South Africa, which has an installed capacity of 45 megawatts [MW] for a population one-third the size of Nigeria's. Nigeria's power 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 attract private participation and strengthen power sector performance to remove constraints to economic development. To this end, policy makers set a goal of achieving 40 GW of power 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 electricity trader. Barring South Africa, the country also boasts the largest investment in independent power projects (IPPs) in sub-Saharan Africa. While the state continued to invest in new power generation capacity, the IPPs played an important complementary role in meeting the funding gap.

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 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 Company (NNPC). After a hiatus of a number of years, and the rejuvenation of the reform process under President Goodluck Jonathan, who came into 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 under the new market conditions, and appropriate credit enhancement and security measures put in place to mitigate payment and termination risks.

Nigeria thus represents a potentially illuminating 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? These are some of the questions that will be answered in this article.

The Nigerian electricity sector has generated a great deal of scholarly attention. The early 2000s for example saw a flurry of publishing around the power sector reforms in the country, primarily focussing on what the reform process should focus on and potential pitfalls (Okoro & Chikuni, 2007; Ikeme & Ebohon, 2005). Recent years have seen more research focussing on evaluating the effects of reform (Idris et al., 2013; Erizim et al., 2016), the performance of the "reformed" power sector in general (Oseni, 2011; Sambo et al., 2012; Onuchie et al., 2015; Barros et al., 2014) and governance more broadly within the country's electricity sector (Edomah et al., 2017). Few studies have looked exclusively at investment in independent power projects; what exists has mostly focussed on evaluating individual private power plant performance (Oyedepo et al., 2014) and the challenges facing the privatized power sector (Joseph, 2014), also with regards to developing the country's renewable energy sector (Okafor & Joe-Uzuegbu, 2010; Ozoegwu et al., 2017). This study therefore addresses a key empirical and policy gap in the literature on the country's power sector, specifically speaking to questions on the acceleration and sustainability of private investment in the sector.

1.1 Research approach and methodology

This case study builds on and forms part of a larger body of research that investigates the investment trends, types, outcomes and success factors supporting private investment in the sub-Saharan African power sector through IPPs. As such, the Nigerian case study draws on but also adds to a broader analytical framework that has primarily been derived inductively.

All the IPPs discussed are greenfield, grid-connected installations of 5 megawatts (MW) or more, that have reached financial close, are under construction, or are in operation. A significant amount of data on these installations was collected and analysed. Preliminary sources included a series of World Bank databases, including the Private Participation in Infrastructure (PPI) database, and databases prepared by AidData, among others. 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 was gathered from various primary and secondary sources (including interviews) and triangulated.

It is important to note that IPPs are not uniform. Although the typical IPP structure is understood as a privately-sponsored project with nonrecourse or limited recourse project financing, IPPs in sub-Saharan Africa do not always follow this model. Instead, governments typically hold some portion of equity and/or debt, bringing IPPs closer to a model of a public–private partnership (PPP) than that of the more traditionally conceived IPP. For the purpose of this article, IPPs were 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.

1.2 Limitations of this article

The focus of this paper is power generation, as opposed to transmission or distribution. While inadequate transmission and distribution are clearly constraints to any effort to widen service access, sufficient generation capacity is necessary to be able to serve new customers, improve welfare, and accelerate sustainable economic development. While the article focuses on electric power sector reform policy and the role of independent power projects, there are notable lessons for economic development more broadly. Lastly, a detailed discussion of the environmental externalities attached to specific power generation technologies—which pose growing concern—lies outside the purview of this article.

2. Recent Literature on Power Sector Reform and IPPs in Sub-Saharan Africa

Before the 1990s, virtually all major power generation throughout Africa was financed by public coffers, including concessionary loans from development finance institutions (DAIS). Publicly-financed generation assets were considered core elements in state-owned, vertically integrated power systems (Airgun and Stanislaw, 2002). In the early 1990s, however, a range of factors caused this to change. The main drivers were identified as insufficient public funds for new generation and decades of poor performance by state-run utilities (Jhirad, 1990; Moore and Smith, 1990; World Bank, 1993; Bacon, 1995; Wolak, 1998; Kessides, 2004; Besant-Jones, 2006; Victor and Heller, 2007). Subsequently, African countries began to adopt a new 'standard' model for their power systems, influenced by pioneering reformers in the US, the UK, Chile and Norway (Patterson, 1999; World Bank, 2003).

The standard model for power sector reform has been roughly defined as a series of steps that move vertically-integrated utilities towards competition, and generally include the following activities: corporatization, commercialization, passage of the requisite legislation, establishment of an independent regulator, introduction of IPPs, restructuring/unbundling, divestiture of generation and distribution assets and introduction of competition (Adamantiades et al., 1995; Bacon, 1999; Besant-Jones, 2006; Williams and Ghanadan, 2006; Gratwick and Eberhard, 2008).

Independent power projects with long-term power purchase agreements (PPA) with the state utility, became a priority within the overall power sector reform (World Bank, 1993; World Bank and USAID, 1994). They were considered a solution to persistent supply constraints, and could also potentially serve to benchmark state-owned supply and gradually introduce competition (APEC Energy Working Group, 1997). Independent power projects (IPPs) could be undertaken before sector unbundling. An independent regulator was also not a prerequisite since the PPA laid down a form of regulation by contract.

While IPPs were considered part of a larger power sector reform programme, reforms were not far-reaching and IPPs subsequently fit precariously into an imperfect structure (Woodhouse, 2006). Most state utilities remained vertically integrated and maintained a large share of the generation market, with private power invited only on the margin of the sector. Policy frameworks and regulatory regimes, necessary to maintain a competitive environment, were limited. International competitive bids for those IPPs that were developed were often not conducted because of very short time frames, resulting in limited competition for the market and, due to long-term PPAs, no competition in the market (Malgas and Eberhard, 2011; Kapika and Eberhard, 2013). These long-term PPAs and often government guarantees and security arrangements, such as escrows and liquidity facilities, exposed countries to significant exchange-rate risks.

Although Africa has seen private participation in greenfield electricity projects continue, private investment has been erratic, with a spike in 2007, largely due to the financial close of one large project, Bujagali, followed by a trough and then another flurry of activity from 2012 onward (Eberhard et al., 2016). The result has been a hybrid (part private, part public) solution. This was neither expected nor predicted by the early framers of power sector reform theory and therefore requires fresh analysis and a new approach as stakeholders find themselves in untrodden territory with prominent state-owned and private actors.

Despite ongoing funding from the private sector, investments are insufficient to address Africa's power needs: two out of three households in sub-Saharan Africa, close to 600 million people, have no electricity connection at all. With only 25 percent of the population currently with electricity access, poor supply is the rule, not the exception. The cost of meeting 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 the total spending is needed for capital investment ($26.7 billion a year); the remainder is for operations and maintenance (O&M). Of capital investment, about $14.4 billion is required for new power generation each year, and the remainder for refurbishments and networks (Eberhard et al., 2011: 60).

Tackling existing utility inefficiencies, which include system losses, under-pricing, under-collection of revenue and over-staffing, would make an additional $8.24 billion available, but a funding gap of $20.93 billion would still remain (Eberhard et al., 2011).

IPPs have taken root in less than two dozen countries in sub-Saharan Africa. Why have some countries been more successful than others in attracting IPPs? And which factors are important in enabling and sustaining private investment in power in developing countries? Building on pioneering work related to private investment in electric power across the developing world (Woodhouse 2006), Eberhard and

Gratwick (2011) inductively devised a set of country and project specific success factors, based on rigorous comparative case study analysis across sub-Saharan Africa, which ultimately led to the balancing of investment and development outcomes as a necessary precondition for successful projects. This analytical framework has in turn been refined through additional case studies and in depth country observations (Eberhard and Gratwick 2005; Malgas 2008; Gratwick, Ghanadan, and Eberhard 2006; Kapika and Eberhard, 2013). While not explicitly drawing on theoretical frameworks used to understand the determinants of inward foreign direct investment (FDI) (Anyanwu, 2012; Asiedu, 2006; Busse & Hefeker, 2007), the success factors of public-private partnerships (Osei-Kyei & Chan, 2015; Babatunde et al., 2012), as well as the drivers of private infrastructure provision in developing countries (Banerjee et al., 2006; Ng & Loosemore, 2007), the IPP success factors derived by Eberhard and Gratwick (2011) from the case studies show remarkable overlap with these fields. This research thus contributes to a broader body of literature concerned with the attraction and sustainability of private infrastructure investment in developing countries – in this case specifically based on the experience of Nigeria.

At the country level, the investment climate, sector policies and reform, and regulatory certainty are all relevant – but recent research indicates that more prosaic issues such as least-cost power planning linked to timely initiation of competitive procurement for new power are perhaps more significant (Eberhard et al., 2016). At the project level, traditional project finance concerns remain important — for example, equity and debt structuring, secure revenue flows, robust power purchase agreements with appropriate risk allocations, credit worthy off-takers or credit enhancement, guarantees and other security and risk mitigation mechanisms. In this paper, as we examine the record of IPPs in Nigeria, we therefore give particular attention to the relevance of planning and procurement issues in securing and sustaining private investment. Closing Africa's power infrastructure funding gap inevitably requires undertaking reforms to reduce or eliminate system inefficiencies. This will help existing resources to go farther and create a more attractive investment climate for external and private finance, which still has the potential to grow. With the original drivers for market reform still present, private sector involvement appears inevitable in the future.

3. Nigeria's Electricity Sector: An Overview

3.1 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 PHCN through the establishment of several companies to take over the assets, liabilities, functions, and staff of the holding company
- The establishment of the Nigeria 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 EPSRA, 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 Power Holding Company of Nigeria, which was tasked with preparing the successor companies (see table 1) for independent commercial operation and eventual privatization (Okoro and Chikuni, 2007).

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 divesture 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 Electric Power Company (KEPCO) offered to purchase 51 percent of Egbin Power for US$280 million. However, this deal was delayed by unresolved labour issues and the lack of a credible power purchase agreement (PPA) or agreements on pricing and the gas supply (allAfrica, 2013).

Table 1. Successor Power Generation Companies[1] to the National Electric Power Authority, Later Privatized, Nigeria

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

Source: Compiled by the authors from various primary and secondary sources.

3.2 The reinvigoration of reforms (Jonathan era)

The 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 divesture, and (3) reforming the fuel-to-power market. These policy objectives were reaffirmed and elaborated in the Roadmap for 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

[1] 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 purchaser backed by credit enhancements, providing a framework for settling labour disputes, and strengthening the regulator and licensing regime. The divestiture strategy outlined in the road map called for the sale of the distribution and thermal generation companies (a minimum of 51 percent), the concessioning 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 2). The 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 for Public Enterprises (BPE), which has driven the privatization programme, and the NERC, which has developed market rules and tariff regulations.

Table 2. 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 Enterprise (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

Key institution	Functions
Nigerian Bulk Electricity Trader (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.

3.3 Privatization

In December 2010, 11 distribution companies and 6 generation companies[2] were ready for privatization. The BPE led the process, requesting expressions of 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 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.

[2] These included five of the original unbundled generation companies with the addition of Geregu I, commissioned in 2007. The Egbin negotiation was handled separately.

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, 2013a). 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 expected to be 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. This stands in stark contrast to the IPPs described in Section 4, which have experienced fewer construction delays and operate closer to full capacity.

In line with government's privatization programme, 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[3] 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.

[3] See table 8 for a list of preferred bidders.

3.4 Market evolution and financial sustainability

Nigeria's policymakers envisage the power market evolving through a number of stages, as outlined in table 3. The initial stage of unbundling, privatization and the establishment of a bulk energy trader is substantially complete. The next stage involves a transitional energy market, including a move to competitive procurement of new power. To simplify procedures for this, the NERC published *Regulations for the Procurement of Generation Capacity* (NERC, 2014); prior to this, IPPs had all obtained their licenses through unsolicited and directly negotiated proposals. The regulations aim to establish a systematic, transparent, and competitive process to ensure the procurement of new capacity at least cost to the consumer. The system operator is required to publish a five-year demand forecast and an annual generation report. The report indicates that IF contracting for new capacity is required within 12 months, the buyer (a creditworthy distribution company or Nigerian Bulk Electricity Trading Plc, NBET) may begin procurement procedures (NERC, 2014).

Table 3. Evolution of the Power Market, Nigeria

Market Stage	Market Characteristics
Pretransition	Unbundling and privatization of PHCN
	Establishment of 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: [a] Successor companies actually commenced functions in the pretransitional stage. [b] Distribution companies can enter into bilateral contracts during the TEM, in defined circumstances.

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.

Rules have been developed to govern contracting for both the transitional and medium-term stages. The bulk trader, NBET, is intended to act as the credible off-taker and aggregator to guarantee liquidity in the market. Electricity should be bought from successor generation companies (NIPPs and IPPs) through PPAs, and then sold on to distribution companies and eligible customers. In future, the bulk trader need not be the only off-taker; any creditworthy distribution company or eligible customer will be able to negotiate a PPA with a generation company or an IPP. The bulk trader is required to be in place only until distribution companies have established their creditworthiness, and until the accounting, managerial, and governance systems are able to handle multiple buyers and sellers (PACP, 2010).

Despite considerable delays and challenges, privatization now seems irreversible. It is remarkable that private investors reached financial close without TEM or World Bank partial risk guarantees (PRGs). However, following the successful liberalization of Nigeria's telecommunications industry, investors are aware that the market has enormous growth potential, and probably take comfort from the fact that the reforms are supported at the highest political level.

Serious challenges remain; these are outlined below:

- Revenue collection is inadequate to cover the costs of power delivery; that is, insufficient revenue is flowing from consumers—through distribution companies—to generators, gas suppliers, and investors. In response, the Central Bank of Nigeria devised a financial rescue package to inject liquidity into the sector and address legacy debts. These amounts are to be repaid on the understanding that NERC-approved tariffs will include a premium over a ten-year period to fund these debts. However, in March 2015, the NERC arbitrarily removed assumptions of distribution companies' collection losses. This, in effect, reduced the approved tariffs, and threatened the viability of the sector. When several distribution companies responded by giving notice of force majeure, the new administration (under President Buhari) was forced to broker an agreement to persuade NERC to reconsider its ruling.
- Increased gas supply is critical to increasing the delivery of power to distribution companies and consumers. In late 2014, a decision was made to increase the regulated supply price of gas to US$2.50/million standard cubic feet (mmscf) plus pipeline transport costs of US$0.80/mmscf although this has taken some time to implement.

- Also, in the period leading up to the March 2015 elections, incidents of vandalism and sabotage of gas pipelines continued.
- The investment needed to facilitate the full evacuation of power from NIPPs and generation companies is not forthcoming.
- Transmission constraints hamper the transport of available power throughout the country.
- Distribution companies have barely begun to improve metering, billing, collections, loss reductions, and service quality, and these factors have the potential to turn public opinion against the reform process.
- The TCN remains organizationally fragile. Although the Canada-based Manitoba Hydro International was appointed as management contractor and their contract has been extended until mid-2016, no credible succession plan is in place. Without this, the consequences for the entire power sector could be dire.

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 Exxon-Mobil IPP, more than 50 IPP projects wait in the wings—many of them frustrated by gas constraints and an electricity sector influx. 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.

4. 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. Presently, the installed capacity of Nigeria is estimated to be under 7.5 GW, of which less than 5 GW is available.

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 1). 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).

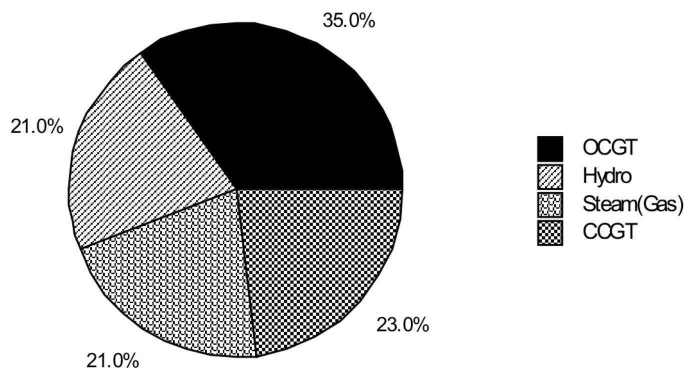

Figure 1. Energy Produced by Technology: Nigeria 2013 averages.
Sources: Compiled by authors from system operator data.
Notes: OCGT: open-cycle gas turbine; CCGT: combined cycle gas turbine

Power plants can be divided into four categories based on their ownership (see tables 4-8): (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[4] (not part of PHCN).

[4] 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.

Table 4. Average Installed Capacity and Electricity Generated in Nigeria by Plant Ownership, 2012–2013

Ownership category	Average installed capacity	Average electricity produced
Successor generation companies	54%	55%
NIPPs	24%	18%
IPPs	20%	24%
Residual state-owned utilities	3%	2%

Source: Compiled by the authors from system operator data.

Note: IPP = independent power project; NIPP = national integrated power project.

Table 5. Successor Power Generation Companies, Now Privatized, Nigeria

Plant	Fuel	Installed capacity (MW)	Available capacity* (MW)	COD	Location	Owners
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/Wood rock
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 authors, based on various primary and secondary source data.

Note: * Available as of September 2013. CCGT = combined-cycle gas turbine; CMEC = China Machinery Engineering Corporation; COD = commercial operation date; MW = megawatts; OCGT = open-cycle gas turbine.

Table 6. 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 (Ihovbor)	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
Gbaran	Gas–OCGT	254	Gbaran, 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 authors, based on various primary and secondary source data.

Note: CCGT = combined-cycle gas turbine; MW = megawatts; OCGT = open-cycle gas turbine.

Table 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 authors, based on various primary and secondary source data.

Note: COD = commercial operation date; CCGT = combined-cycle gas turbine; MW = megawatts; OCGT = open-cycle gas turbine

Table 8. Residual State-Owned Plants, Nigeria

Plant name	Fuel	Installed capacity	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 authors, based on various primary and secondary source data.

Note: COD = commercial operation date; IPP = independent power project; OCGT = open-cycle gas turbine. n.a. = not applicable.

5. Independent Power Project Investments in Nigeria

Independent power projects 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 2 shows the timing of the major IPP investments in relation to key reform interventions.

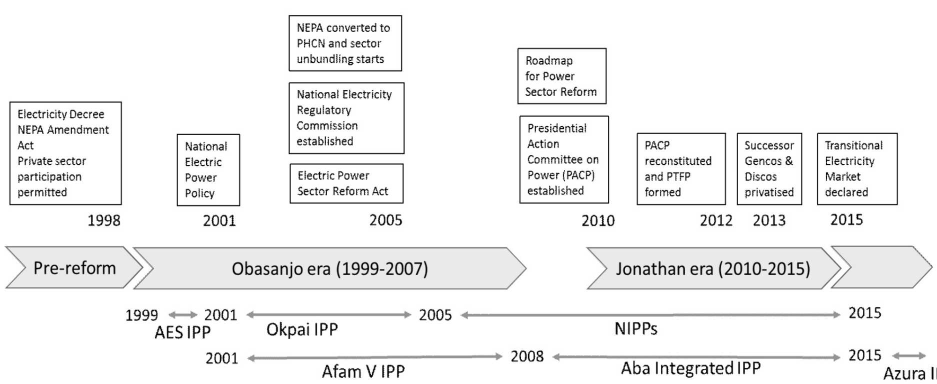

Figure 2. Timeline of Power Sector Reform Interventions and Generation Investments: Nigeria, 1998–2015.

Source: Compiled by the authors.

Note: Discos = distribution companies; Gencos = generation companies; IPP = independent power project; NEPA = National Electric Power Authority; NIPPs = national integrated power projects; PACP = Presidential Action Committee on Power; PHCN = Power Holding Company of Nigeria; PTFP = Presidential Task Force on Power.

The first IPP, AES Barge, was initiated in the pre-reform period. Then two IOC stop-gap IPPs, Okpai and Afam V, were developed with generous, but not-to-be repeated, tax incentives as President Obasanjo 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 TEM and NBET being established, a new set of classic, project-financed IPPs were developed, and Azura is 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 licenses (*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 give chance for more regional and local IPPs to enter the market.

5.1 AES Barge Ltd.

The AES Barge project was the first IPP deal in Nigeria, dating back to 1999 (table 9). Amid an emergency power situation, and following the 1998 passage of a law[5] 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 permanent gas-fired plant with a common PPA. The deal was directly negotiated within a few months between the US-based Enron the Lagos State government, NEPA, and the Ministry of Power and Steel (Eberhard and Gratwick, 2012).

Strong objections were soon raised about the lack of a transparent and competitive process, the excessive contract-termination charges, the lack of penalties for poor performance, and high capacity charges. Mounting public pressure resulted in the deal being modified: the barge-mounted plant was increased to 270 MW and the fuel changed from diesel to natural gas. The

[5] Electricity (Amendment) Decree 1998 and the NEPA (Amendment) Act 1998.

permanent plant was shelved and the new deal was concluded in 2000 (Eberhard and Gratwick, 2012).

Table 9. Overview of AES Barge, an Independent Power Project, Nigeria

Plant	AES Barge	Contract details	13.25-year PPA (build-own-operate)
			US dollar denominated
Location	Egbin, Lagos State		Flat capacity charge (OECD CPI indexed)
Capacity	270 MW		US$19.35/kW/month (November 2006)
			No energy charge
Ownership	95% AES Limited (US)	Financing	US$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, Africa Merchant Bank)
Technology	Open-cycle gas turbines (9x30 MW)	Security	Sovereign guarantee—US$60 million Letter of Credit (Ministry of Finance)
			OPIC political risk insurance
Value	US$240 million (US$888/kW)	Fuel contract	No separate fuel supply contract
COD	June 2001		NEPA (now PHCN) provides fuel purchased directly from Nigeria Gas Company

Sources: Adegbulugbe and others 2007; Eberhard and Gratwick 2012

Note: COD = commercial operation date; CPI = consumer price index; FMO = Netherlands Development Finance Company; IPP = independent power project; KfW = German Development Bank; kW = kilowatts; MW = megawatts; 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.

Before construction was complete (and before filing for bankruptcy), Enron sold its stake in the plant to AES (95%) and Yinka Folawiyo Power Limited (5%); the EPC contract went to AES. The plant began operation in 2001. In the absence of a reform policy and law, initial risk allocation was skewed in favour 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.

5.2 Okpai (Agip)

The Okpai deal also came about after severe electricity supply shortages, and aimed to use the gas being wasted through flaring from Nigeria's old fields (table 10). In 2001, during the Obasanjo presidency, 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). In a package of the most attractive incentives ever offered to private power generation investors in Africa, the successful oil company would be allowed to offset costs under joint venture oil and gas activities and rapidly depreciate their assets.

Table 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: US$13.00/kW/month (2006)
			Energy charge: 2.2c/kWh (2006)
Ownership	60% NNPC	Financing	100% equity financed
	20% Agip Oil Company (Italy)		60% NNPC
	20% Phillips Oil Company (US)		20% Agip
			20% Philips
Technology	Combined-cycle gas turbine	Security	PPA backed by oil revenue of NNPC
Value	US$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 = kilowatts; kWh = kilowatt-hour; MW = megawatts; NNPC = Nigerian National Petroleum Corporation; PPA = power purchase agreement.

A consortium led by Agip Oil won the bid to build the plant, and the PPA was signed in 2001. The project was subject to dramatic cost escalations (from US$300 million to US$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. A dispute among the parties was settled (out of court), and payments were not made to the IPP (Eberhard and Gratwick, 2012).

5.3 Afam VI (Shell)

As with Okpai, 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 11). A consortium led by Shell won the bid in 2001; operations began in 2008.

Arrangements were similar to that of Okpai, and involved a US dollar-denominated PPA and full equity financing. The main difference 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.

Okpai and Afam VI were both entirely equity financed, with the NNPC taking a majority share and the oil companies taking the balance. Generous depreciation allowances made these projects attractive for investors. Thus, these were not classic IPPs relying on nonrecourse project finance.

Table 11. Overview of Afam VI, an Independent Power Project, Nigeria

Plant	Afam Phase VI	Contract details	20-year PPA Afam V (acquire-own-operate) Afam VI (build-own-operate) U.S. dollar denominated PPA
Location	Afam, Rivers State		
Capacity	630 MW		
Ownership	55% NNPC 30% Shell (UK/Netherlands) 10% Elf/Total (France) 5% Agip Oil Company (Italy)	Financing	100% equity financed 55% NNPC 30% Shell 10% Elf 5% Agip
Technology	Combined-cycle gas turbine (3x148 MW gas turbine) (1x230 MW steam turbine)	Security	Letter of Credit (Ministry of Finance)
Value	US$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 = megawatts; NNPC = Nigerian National Petroleum Corporation; PPA = power purchase agreement.

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.

5.4 Aba, an Integrated Power Project

The Aba project (table 12) is a 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, Professor Barth Nnaji, who chairs the lead sponsor, Geometric Power. A 141 MW OCGT plant and a distribution network was developed in the Aba and Ariaria business district under a 15-year lease between Geometric and the Enugu Distribution Company (LeBoeuf et al., 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 expected 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 kilometres (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 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.

Aba was initially financed by corporate sponsors, but as the commercial operation date was delayed, debt built up and 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.

Table 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	US$460 million (including gas and T&D infrastructure)	Fuel contract	Fuel supply agreement with Shell
COD	Currently being refinanced	EPC	General Electric

Source: LeBoeuf et al., 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

5.5 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 13). Investment costs—at US$895 million for a 450 MW OCGT—are high and reflect perceptions of risk. The counterpart 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. 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. 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 the various stakeholders. 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.

Table 13. Overview of Azura, 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 Limited [Mauritius] (97.5%) and Edo State Government (2.5%)	Financing	US$180 million equity (20%) US$715 million debt 15 debt providers including DAIS, for example, IFC, FMO, and commercial banks Main equity sponsors: Azura-Edo Ltd. 97.5% compromising 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	US$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: DAIS = development finance institutions; 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 = megawatts; NBET = Nigerian Bulk Electricity Trader; PPA = power purchase agreement; PRG = partial risk guarantee.

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 guarantee backstops payment obligations by the NBET, which provides security under the PPA in the form of an LC issued by a commercial bank in favour 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. A letter of credit has also been issued 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, in a sense, Azura's development and risk-mitigation costs could be seen as being spread across the large pool of new IPPs currently in the pipeline. As contracts are successfully concluded, subsequent investments should become less complex and less costly to negotiate. Hopefully, they will also require fewer risk mitigation measures.

6. Chinese-funded Projects

China is one of the fastest-growing sources of funding for power projects in Africa (Eberhard et al., 2016). As of 2014, based on financial close, Chinese-funded projects in Africa exceeded IPPs both in total megawatts and total dollars invested (approximately US$13.4 billion, compared to US$11.5 billion). The majority of these projects received funding from the Chinese ExIm Bank, responsible for soft loans and export credit, on the part of the Chinese government.[6] The typical project structure involves an engineering procurement construction (EPC) plus a financing contract, which means EPCs will have a preliminary support letter or letter of interest from the "co-operating banks". Chinese EPCs compete with each other, and the selected EPC generally starts work—using 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%) are entered into between sub-

[6] Industrial and Commerce Bank of China and China Development Bank also provide finance, with the latter primarily providing commercial loans. In addition, both the China Construction Bank and Bank of China are involved in energy sector investments. The Chinese ExIm Bank and the China Development Bank are state owned. Of the others, the government owns two-thirds, and one-third is publicly traded. The China Africa Fund is another source of concessionary finance.

Saharan African governments and the Chinese banks. The remaining 20 percent, are given directly to Chinese special purpose vehicles or EPCs for the project.

Countering the popular claim that Chinese firms are mainly interested in Africa's resources, there is no clear correlation between Chinese-backed investment in electricity generation and the resource wealth of the countries invested in. By early 2016, Chinese-funded generation projects existed in 19 African countries, only some of which can be seen as resource rich. Only eight have IPPs, again signalling no apparent pattern. Excluding macroeconomic considerations, the one notable characteristic is the preponderance of large hydropower projects (comprising 4.9 GW, or approximately 63 percent, of total Chinese-funded capacity) for which the Chinese have become renowned worldwide.

In this section, three Chinese-funded deals that had reached completion in Nigeria by early 2016 are examined.

6.1 Olorunsogo I

Phase I of the Olorunsogo plant was completed in 2007 (table 14). It was built by the Chinese EPC contractor SEPCO-Pacific Partners. The original agreement was to have 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 US$115 million with a 6 percent interest rate, 6-year grace period, and 12-year maturity period (*Premium Times* 2014; AidData, 2012a).

Table 14. Overview of Olorunsogo 1 Power Plant, Nigeria

Plant	Olorunsogo I (Papalanto)
Location	Olorunsogo, Ogun State
Capacity	335 MW
EPC	SEPCO-Pacific Partners
Technology	OCGT
Value	US$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 = megawatts; OCGT = open-cycle gas turbine.

After a series of delays, a shortage of gas, and a lack of funds, PHCN defaulted on its payments to SEPCO. The Debt Management Office took over the debt and, in line with 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).

6.2 Omotosho I and II

The Omotosho I deal was structured in the same way as Olorunsogo (table 15). The PHCN was supposed to fund 35 percent of the plant, with the EPC contractor (China Machinery Engineering Corporation, CMEC) funding the remaining 65 percent. The Export-Import Bank of China also provided a loan of US$115 million (AidData, 2012b).

As with Olorunsogo, government could not meet its payment obligations; and by September 2012, PHCN had accrued US$104 million in unpaid debts to CMEC. 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, following the previous payment defaults by the government, was not funded through the Export-Import Bank of China.

Table 15. Overview of Omotosho I and II Power Plants, Nigeria

Plant	Omotosho I	Plant name	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	US$361 million	Value	—
COD	2008	COD	2012

Source: AidData, 2012b.

Note: COD = commercial operation date; EPC = engineering, procurement, and construction; MW = megawatts; NIPP = National Integrated Power Project; OCGT = open-cycle gas turbine.

— = not available.

6.3 Zungeru hydropower project

In September 2013, the Nigerian government signed a deal with two Chinese firms (China National Electrical Engineering Corporation and Sinohydro) to build the 700 MW Zungeru hydropower plant (table 16). Government approved funding for 25 percent of the project, with the Export-Import Bank of China funding 75 percent via low-interest loans. The project is the largest power project in Africa to be funded with government concessional loans (*This Day Live*, 2013b).

Table 16. Overview of Zungeru Hydropower Plant, Nigeria

Plant	Zungeru
Location	Zungeru, Niger State
Capacity	700 MW
EPC	CNEEC-Sinohydro Consortium
Technology	Hydropower
Value	US$1,293 million
COD	2017 (expected)

Source: Compiled by the authors from various primary and secondary sources.

Note: 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 US$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 and controversially cancelled by the Nigerian government and awarded to Sinohydro. CGGC/CGC disputed the cancellation, and negotiations have stalled for several years (*This Day Live*, 2014).

7. 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 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 US$7.5 billion.

Table 17. Renewable Energy Targets for 2025, Nigeria

Energy type	Target (megawatts)
Small hydro	2,000
Solar PV	500
Wind	40
Biomass	400

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

The plan includes capacity targets and an overall goal of 23 percent of electricity supplied from renewables by 2025 (table 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.

8. 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 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) into reality. 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 voices 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 in 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. Exxon-Mobil'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 has 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, have added risks 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 sustainability of developing countries' power sector reforms and investment programmes depends on it.

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