Hybrid power markets in Africa: Generation planning, procurement and contracting challenges

Isaac Malgas*, Anton Eberhard

Management Programme in Infrastructure Reform & Regulation, Graduate School of Business, University of Cape Town, South Africa

A R T I C L E   I N F O

Article history:
Received 29 April 2010
Accepted 1 March 2011

Keywords:
Power
Sector
Reforms

A B S T R A C T

African power sectors are generally characterised by insufficient generation capacity.
Reforms to address poor performances in the 1990s followed a prescribed evolution towards power markets that would allow wholesale competition amongst generators and so lead towards efficiency improvements. Despite reforms being embarked, competitive power markets have not been established in Africa; rather, the result has been the emergence of hybrid markets where state-owned generators and IPPs operate devoid of competition; and although IPPs have emerged in a number of African power sectors, many countries still do not have sufficient generation to meet their electricity demands.
This paper investigates the development of private generation power projects in Africa by analysing data collected from both primary and secondary sources in four case studies of power sectors in Ghana, Côte d’Ivoire, Morocco and Tunisia. It identifies how planning and procurement challenges have lead to difficulties in adding sufficient generation capacity in a timely manner, exacerbating the problem of insufficient generation capacity in Africa. It provides suggestions as to how these frameworks could respond more effectively to the capacity challenges faced by hybrid electricity generation markets, and how broader power sector reforms should be guided to reflect the challenges of hybrid markets better.

1. Introduction

Power sector reform in Africa has been widespread, although mostly not as deep as originally intended. There have been attempts to improve the performance of state-owned utilities, new regulatory agencies have been created and private investment has been encouraged in the form of Independent Power Producers (IPPs). But nowhere in Africa do we find examples of the standard power sector reform model which sought to achieve fully unbundled, privatised and competitive electricity markets.
Instead what has emerged in Africa, and many other developing countries, has been hybrid electricity markets where the incumbent state owned enterprise (SOE) has retained a dominant market position while privately-owned IPPs have been introduced on the fringes (Gratwick and Eberhard, 2008). Hybrid public-private power markets give rise to new problems, not least of which are the challenges of attracting sufficient new investment and ensuring security of supply. As the results of a recent African Infrastructure Diagnostic Country (AIDC) study have indicated, power generation capacity is under-developed and inadequate to meet electricity demands in most Sub-Saharan African countries.

Indeed the installed power generation capacity across the continent is more or less equal to a single European country, Spain (Eberhard and Foster et al., 2009).
Confusions arise in hybrid power markets around who has responsibility for generation planning, procurement and contracting. The extent of these problems and challenges become evident in a series of case studies we have undertaken on power sector reform and IPP investments in four African countries: Ghana (Malgas, 2008), Côte d’Ivoire (Malgas and Gratwick, 2008), Morocco (Malgas and Gratwick et al., 2008) and Tunisia (Malgas and Gratwick et al., 2007).
Eight IPP projects were studied which, in 2008, represented half of the installed IPP capacity in Africa. These IPPs are Takoradi II in Ghana, CIPREL and Azito in Côte d’Ivoire, Jorf Lasfar, CED and Tahaddart in Morocco and Rades II and SEEB in Tunisia. In addition, we noted generation plants that were planned, negotiated and sometimes developed, but which did not enter into operation as planned. An example is the Western Power IPP in Ghana, which was fully constructed but produced not a single megawatt commercially. Much time was spent developing the SIIF (Accra) and AES Sirocco IPPs in Ghana, as well as the Barca IPP in Tunisia, but none reached financing closure. Further examples of problematic investments include the Cap Ghir and Al Wahda plants in Morocco which, at the time of publication of this paper, had still not reached final agreement between the stakeholders.

* Corresponding author. Tel.: +27 21 550 5538; fax: +27 86 668 6933.
E-mail address: isaac_malgas@yahoo.com (I. Malgas).

0301-4215/$ - see front matter © 2011 Elsevier Ltd. All rights reserved.
doi:10.1016/j.enpol.2011.03.004
Two of the eight case study IPPs were commissioned and produced power, but did not progress to their next intended stage of development. These were the Takoradi IPP in Ghana (where ongoing negotiations to complete the steam phase and operate the plant in combined-cycle mode have stalled due to the high power charges expected by sponsors and the lack of guarantees from the government); and the Azito plant in Côte d’Ivoire (which has also been waiting for a steam phase to operate as a combined cycle plant after a political coup in 1999 left the future of the power station, the power sector and the country uncertain).

A number of the case study IPP plants also experienced delays. These included the Rades II IPP in Tunisia, where commissioning was delayed by approximately eight months mainly due to concerns over the land rights and subsequent rights on the plant equipment; the Al Wahda and Cap Chir plants in Morocco, which have been delayed due to fuel and environmental concerns, respectively; and virtually all of Ghana’s plants scheduled after Takoradi II have seen delays for a host of reasons, including the revived Bui hydro plant that has been planned since 1966.

Two of the case study countries experienced domestic power shortages and two managed to maintain adequate generation reserves. Ghana has experienced severe electricity blackouts as a result of insufficient generation capacity over the last decade. In addition, the country has faced disputes and arbitration on three stop-gap emergency plants that were ordered to curb the rolling blackouts experienced during the droughts of the 1990s, but which later became redundant as hydrological conditions and availability of hydro power improved. Côte d’Ivoire has been able to maintain adequate reserves, despite a civil war, and has been able to export to neighbouring Ghana in its time of need. Morocco, like Ghana, has not been able to maintain adequate domestic power reserves, but managed to import sufficient power from Spain to avert load-shedding. Lastly, Tunisia has been successful in maintaining adequate generation reserves.

These similarities and differences give rise to the following questions. What were the factors that led to the different outcomes for the four cases described? What were the forces that assisted a country like Tunisia to ensure sufficient generation, and how did the presence or absence of these forces work against a country like Ghana in attracting adequate investment in generation capacity? Perhaps, more importantly, how could countries like Ghana (and many other countries like it in Sub-Saharan Africa) respond more effectively to ongoing challenges which frustrate attempts to meet growing needs for power?

2. Factors contributing to insufficient generation capacity

A common theme that emerges from our case studies is the failure of many hybrid power markets to procure and contract new power in time. Planning, procurement and contracting functions, which were previously undertaken by monopoly state-owned utilities now “fall between the cracks” when hybrid power markets are introduced and are either neglected, or are performed inadequately.

2.1. Generation planning in hybrid markets

In the past, the incumbent state-owned power utility generally assumed responsibility for generation expansion planning and, because these utilities were generally run by engineers, the tendency in the past was to plan conservatively, i.e. to build more capacity than was actually needed in order to ensure that the lights never went out. 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 under-investing: they simply do not have sufficient financial resources. Pressures have thus grown for power sector reforms which have encouraged the entry of IPPs and new private investment that supplements the utilities' efforts. However, in these hybrid markets it often became unclear who was responsible for generation expansion planning. Would the private sector, or “the market”, simply respond to needs for more power? What was the role of planning? And, if planning was still necessary and important, who was responsible—the utility, the regulator, or the government? And if the government takes over this function, does it have the capacity to undertake timely, flexible and relevant planning?

With the introduction of IPPs, planning also needed to take into consideration a host of additional legal and financial issues. Private finance assesses risk differently and, as a result, supplementary security and risk mitigation measures become necessary. In addition, the linkages between planning and investment needed to be dealt with differently. Previously, national utilities undertook planning, investment and procurement. Now, in hybrid markets, government (and sometimes also state utilities) would undertake generation expansion planning—hence new, explicit processes need to link the planning process to procurement of private investment.

2.1.1. Evolving planning frameworks

The experiences in generation planning in our four case study countries have been diverse. In Ghana, power sector reforms brought about a change in planning accountability when the national utility, the Volta River Authority (VRA), no longer had sole responsibility for planning and the newly established Energy Commission became the new overall custodian of the country’s planning function. The VRA performed detailed power sector planning prior to reforms, whereas the Energy Commission’s mandate was limited to indicative planning. Apart from indicating the size, type and timing of generation capacity needed in the power sector, the Energy Commission has no obligation or mandate to initiate procurement or contracting of new power.

In many cases, planning in the Ghanaian context has been shown to be unrealistic with timelines that do not take into consideration the real challenges of the related developing generation projects. An example is the Energy Commission’s Strategic National Energy Plan (2006) which has unrealistic time frames for Ghana’s first nuclear power plant, and little appreciation of how it would be financed. Although the Ministry of Energy supposedly facilitates the development of new generation projects, and has entered into power purchase agreements with prospective IPPs, the VRA and the Electricity Company of Ghana (ECG) have also separately undertaken commitments to enter into PPAs with private generators. The lack of coordination between these institutions and the absence of clear and enforceable rules for project procurement has meant that new power has not been procured in time and the country’s economy and people have suffered from inadequate power.

In the case of Côte d’Ivoire, the planning function remained with the national utility, Energie Electrique de Côte d’Ivoire (EECI), when the utility handed over the management of its operations to a private operator at the inception of reforms in 1994. The same departments that had been responsible for planning in the EECI were later incorporated into Société d’Opération Ivoirienne d’Electricité (SOPIE), an Ivorian Electricity Operations Company that was set up in 1998 to coordinate power flows in the national grid, including imports and exports to and from neighbouring countries. SOPIE was assigned the responsibility of planning for new generation requirements, and for capital and major refurbishment projects in the sector (Veï, 1999: 22). At the same time, Société de Gestion du Patrimoine du Secteur de l’Electricité (SOGEPE), an Electricity Sector Asset Management Company was established to manage the state’s
assets in the power sector; to oversee and manage the finances of the sector; to raise capital for power sector investments; and to ensure financial control in the sector (SOGEPE, 2004).

Unlike Ghana, planning, therefore, remained with a specific entity. In part, this was facilitated by the specific form of private participation introduced in Côte d'Ivoire. The private concessionaire was primary responsible for operation of the electricity system, but not for new investment. This responsibility remained with the state including, as mentioned above, the planning function. The state was clear about its responsibilities and there appears to have been sufficient foresight regarding future power needs. Côte d'Ivoire was the first country in Africa to procure an IPP (CIPREL) and followed this milestone with the successful procurement of a second IPP (Azito). The country continued to enjoy surplus capacity (facilitated in part by depressed demand during the civil war) and was able even to export power. The surplus capacity is currently diminishing and, in keeping with its strategy of being a major power exporter in the region, Côte d'Ivoire has started the process of procuring additional generation capacity.

In Morocco, when IPPs were introduced, the national utility, Office Nationale de l'Electricité (ONE), was no longer solely responsible for new generation. Yet it continued to undertake planning and assumed responsibility for translating planning into bidding and procurement processes for IPPs. This was made possible by strong political leadership and purposeful state action: i.e. the national utility was told that IPPs were necessary to bring in private investment, but it was also given direct responsibility to make sure that it happened. Under the Build–Transfer–Operate (BTO) framework in Morocco, the utility is the owner of the generation assets despite private operation of the plant.

Looking at the data from the AIDC study across more than 20 African countries, it is clear that the experiences of Côte d'Ivoire and Morocco are unusual, while Ghana's is more typical (Eberhard and Foster et al., 2009). The data suggests that power sectors that have transferred their generation planning functions from the national utility to new institutions risk experiencing new problems in ensuring timely and effective procurement of IPPs. Not only does clear institutional responsibility need to be allocated, but the linkages between planning, investment and procurement of IPPs need to be explicit. Strong state and political leadership seems to be crucial to ensure that the incumbent utility works positively with the state to achieve national goals and objectives. Appropriate governance mechanisms will need to be put in place to ensure that the planning assumptions and scenarios developed by the national utility are in the national interest rather than narrower utility concerns.

Leaving the planning function with the national utility is clearly not the only option. It could be transferred to government or the regulator, or to a new, independent planning body, or attached to an unbundled, independent transmission and/or system operator. But if this transfer is to be successful, the planning function will need to be adequately resourced in terms of people, software and institutional capacity.

2.1.2. Flexibility in generation planning

The institutional location of power sector planning is important; equally important is the nature of that planning. A rapidly changing environment means that planning needs to be up-to-date and flexible. What is not needed, are Master Plans that sit on office shelves for years and years.

In Ghana, the large number of plants that were halted in the planning stages without realising construction demonstrates the difficulty in planning generation projects when there are multiple constraints. Ghana has more generation power projects in the pipeline than any of the other three other countries examined in this paper. Given its low success rate in bringing projects to completion, it is easy to appreciate the approach that the government has taken, i.e. to increase the number of planned projects in the face of attrition. While this approach may increase the chances of adding generation capacity, the benefit of a more carefully crafted and targeted approach with fewer projects would have created more investment certainty.

Côte d'Ivoire, on the other hand, has adopted a strategy that gives it greater flexibility in generation planning. With the discovery of natural gas and realising that it could benefit from the problems of insufficient capacity in neighbouring West African states, it commissioned the country's second IPP and exported surplus capacity to neighbouring countries, a strategy that Tunisia also intends to follow. In 2006, Cote d'Ivoire exported to neighbouring countries the equivalent of almost all the electricity produced by the Azito IPP. The benefit of this strategy could be seen in 1999, when the country was able to maintain sufficient generation capacity despite the political and investment uncertainty that came with the coup d’état.

In contrast to Ghana, planning and forecasting in Côte d'Ivoire has not only been facilitated by the presence of domestic fuel but also by a relatively more stable currency, showing that the environment in which planning occurs is as much a contributor to successful planning outcomes as the planning process itself. A similar contrast can be made with respect to Ghana and Morocco; although the latter had hardly any domestic primary energy resources, its stable economy provided leverage to attract investment.

Transmission links between North Africa and Europe have also played a significant role in bringing flexibility to planning in the Moroccan case where delayed contracting and commissioning of power stations resulted in more than 9 per cent of the country's electricity requirements being imported in 2007. Imports were expected to be in excess of 12 per cent in 2009, after the strengthening of the interconnection. Increased imports have been necessitated by delays in developing new plants (environmental concerns in the case of the Cap Ghir coal-fired power plant and the securing of fuel for the Al Wahda combined cycle gas plant).

Tunisia has also managed to maintain adequate generation capacity. At the time when IPPs were procured, the national utility, Société Tunisienne de l'Electricité et du Gaz (STEG), had sufficient generation reserve capacity and was able to meet demand when IPPs took longer than expected to come on line. Many countries take longer than expected to procure their first IPPs (mainly due to inexperience in private contracting). In addition to generation reserves, transmission links with neighbouring Algeria and Libya meant that Tunisia had added defences against the risk of insufficient capacity. Tunisia also has domestic natural gas to fuel its power stations and has access to the gas networks of its neighbours. Since Rades II was developed, the country has expanded its gas distribution infrastructure making it easy for electricity and gas consumers to switch between the two modes of energy supply, should this be necessary. These factors have given Tunisia greater flexibility in its planning strategy. Furthermore, natural gas plants have shorter lead times for development and commissioning of generation capacity; it puts the utility in a less challenging situation than those countries that have to procure technologies that carry longer planning and development phases and are more prone to environmental constraints, as was found in Morocco with the Cap Ghir coal-fired plant.

Flexibility in planning is crucial for ensuring security of supply and a least cost mix of generation plant, including a combination of exports and imports.
2.1.3. Project planning and risk management

In hybrid markets, project planning and appraisal is often moved to newly formed institutions that lack the capacity to execute these functions effectively, especially with respect to risk management.

In Ghana, the main project sponsor for the Western Power IPP was the state-owned oil company, the Ghana National Petroleum Company (GNPC), which had no prior experience in the appraisal of generation power projects and was entering a new business environment with the development of IPPs. The irony was that the sponsor, whose main business it was to explore fuel options and secure and make available commercial fuels for Ghana, was unable to secure the fuel to operate the plant. The plant was procured but never generated any electricity commercially. The Société d’Electricité d’El Bibli (SEEB) IPP in Tunisia is another example of an IPP where the fuel risk was not adequately assessed and which subsequently under-performed.

The Western Power and SEEB IPPs were not the only projects where upstream fuel issues effected outcomes. During the earlier years of the operating life of Ghana’s first IPP, Takoradi II, there were problems with fuel availability and quality, lowering the expected output from the plant. Similarly, in Morocco, fuel availability continues to cast a shadow on the development of the Al Wahda IPP designed to use natural gas from Algeria.

2.1.4. Demand side management planning

Generation expansion planning is best undertaken within an integrated resource planning framework where demand-side options are assessed along-side least-cost generation technologies. Once again, there are many examples in our case studies of demand-side planning being inadequate. In Ghana, it took four years for the government to implement a specific DSM programme that could have significantly changed the electricity demand load profile and limit the amount of load-shedding that occurred.

In Morocco, the rural electrification programme was a high priority for the national utility, the power sector and the country, with funds committed to the programme from the state, OPEC and local municipalities— at a time when no funds were available for additional generation expansions. Despite the country heading for power shortages, rather than retard the rate of electrification to help reduce demand which was fuelled in part by a low tariff structure at the residential level, the programme was accelerated to be completed earlier than initially scheduled. This example illustrates the importance of integrating electrification planning with generation planning.

Power sector planning is no trivial task. Adequate systems, human resources and institutional capacity need to be secured and nurtured. Hybrid power markets create additional challenges of integrating public and private options, incorporating risk management requirements as well as flexibility to ensure security of supply. Thus any power sector reforms that bring in IPPs while maintaining the incumbent state-owned utility, need to deal with these challenges explicitly and purposefully. In addition, there need to be clear criteria whereby new-build opportunities are allocated to either the national utility or to IPPs. In hybrid power markets, the incumbent state-owned utility often continues to invest in new generation capacity in parallel to IPPs coming into the market, or if they have not built new generation for some time, they often continue to harbour ambitions for doing so. In these contexts, the planning function needs to develop transparent criteria which make clear what the state utility will do in the future and which projects will be bid out to the private sector. The latter process is, in itself, also fraught with challenges and it is to these that we now turn.

2.2. Generation procurement

Procurement of generation infrastructure requires specified processes to be followed to optimise the total cost of the acquisition, to minimise opportunities for corruption and to promote transparency and ensure the timely acquisition of generation capacity.

2.2.1. Procurement procedures

Procurement of new generation capacity generally needs to be done in accordance with established rules and regulations governing procurement opportunities, tendering, bidding and awarding of contracts. Non-adherence to policies and guidelines can also lead to a number of problems, as evidenced in Ghana. Here, despite the Ghanaian policy of contracting large infrastructure projects through international competitive bidding (ICB) procedures, no ICBs have been launched for any IPP projects; to date, all generation projects have been initiated through unsolicited offers and negotiated deals, despite the country’s procurement policies favouring competitive tendering. Failure to adhere to domestic policies may prompt investors and lenders to withdraw from deals, further contributing to the problem of insufficient capacity. An example was the attempt in Ghana to contract emergency power from Faroe Atlantic Company from the UK. The Ministry of Finance entered into a PPA without parliamentary approval, despite this being a requirement for such large-scale projects. The PPA was subsequently cancelled by the Ghanaian government when extra hydro electric resources became available. Faroe Atlantic took the government to court and eventually lost the case because the contract was regarded as null and void because the necessary approvals had not been obtained (Oxford and Beaumont, 2006).

The situation is exacerbated when there is no clarity on who should be the contracting authority or institution. In Ghana, IPPs have been negotiated by the VRA, the 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. Clarity, transparency and consistency in procurement policies and practices are clearly important when contracting IPPs who have to invest substantial risk capital in developing their investment proposals and plans.

2.2.2. The influence of development finance institutions and benefits of ICBs

In contrast to Ghana, the other three countries have all followed competitive bidding processes for the procurement of their plants (with the exception of Tunisia’s SEEB IPP, where competitive bidding is not required under the country’s hydrocarbon framework). Apart from SEEB, all the commissioned IPPs examined in Côte d’Ivoire, Morocco and Tunisia had loan assistance from development finance institutions. Development finance institutions have clearly stated lending conditions for the procurement of infrastructure projects for which they provide financial assistance. The World Bank, for example, makes additional financial assistance available to establish the required procurement policies and practices.

Tunisia has gone as far as legislating competitive tendering as a requirement for generation infrastructure acquisitions and, as a result, no provision exists for unsolicited proposals within the power sector’s generation procurement framework. Here, governance arrangements during IPP procurement also work well to ensure adequate oversight when negotiating and contracting the country’s first IPP. The Commission Supérieure de la Production Indépendante d’Electricité (CSPIE) and its lower-tiered partner, the Commission Interdépartementale de la Production Indépendante d’Electricité (CIPIE) were established as oversight institutions. These two
commissions, which were set up in 1996 just before the tender for Rades II was issued, were answerable to the Ministry of Industry and Energy but retained some degree of independence and ultimately served as the de facto regulators during the early days of the first IPP. Both the CSPIE and the CIPIE, which were temporary commissions that operated until all project contracts were signed, may be credited with what has been deemed a well-organised and ultimately fair and constructive bid.

The procurement of Rades II was lauded by the World Bank as one of the best IPP deals executed at the time. The project attracted considerable interest amongst IPP sponsors, with seventeen consortia responding to the tender invitations. More or less the same sentiments hold for Morocco’s Jorf Lasfar plant, albeit with less interest shown from foreign investors for Africa’s largest IPP transaction to date. The record deal set the stage for future investments in the form of the CED and Tahaddart IPPs. Through competitive bidding, Côte d’Ivoire, Morocco and Tunisia were not only able to attract a number of investors, they provided opportunities for innovation and cost-cutting by stipulating general criteria for plant requirements. In the case of Côte d’Ivoire, the government set the range for the turbines for CIPREL at 75–105 MW allowing more companies to compete in the bidding process, and facilitating the achievement of lower power charges in the PPA. The involvement of the World Bank also determined the procurement procedures for Azito, the country’s second IPP, when the ICB process produced an even lower power charge than that for the first IPP. The same cannot be said for Ghana’s Takoradi II where an ICB was passed over for a direct negotiated deal with the IPP sponsor. After the deal was finalised, the Ghanaian government decided that the full energy charge should not be passed through to consumers due to the elevated cost. The government also later insisted on buying the remaining 50 per cent shareholding from TAQA (the Abu Dhabi National Energy Company). One of the main reasons for the government using funds to buy existing plants back from IPPs, rather than putting the scarce resources to better use by developing new capacity at a later time, is because the Kufuor administration felt that the charges were too high—a situation brought about partly due to non-transparent procurement processes and the absence of competition (Awuni, 2007).

2.2.3. Competitive bidding with a twist

For certain projects in Côte d’Ivoire and Morocco, ICBs were not executed for the entire turnkey contract. In the case of CIPREL in Côte d’Ivoire and the CED and EET plants in Morocco, sponsors were first selected by the off-takers and, thereafter, the EPC and O&M contracts were put out on tender in an ICB. Although this practise has the same effect of pushing down the price of power through competition for supply tenders, there is no competition amongst potential equity partners and the off-taker has to negotiate the IPP sponsors’ return on the project. By pre-selecting plant sponsors, off-takers of power rule out other potential sponsors who may have lower project costs and lower returns on equity, including participation of local sponsors. Although IPP sponsors may be pre-selected for strategic reasons by governments and off-takers, pre-selection could exclude other potential sources of investment.

2.2.4. Allocation of generation investment opportunities

None of the case study countries has ruled out state sponsored investment in generation and state-owned enterprises (SOEs) remain an option to expand generation capacity. In three of the countries (the exception being Tunisia), the main driver for private investment still persists: SOEs lack sufficient finances to fund fully power expansion needs. IPPs will, therefore, continue to play a crucial supplementary role. However, the countries lack clearly stated criteria for allocation of investment opportunities between SOEs and IPPs.

In Ghana, despite the government announcing its intention to increase private ownership in generation, the VRA took over an increasing share in the Takoradi II IPP. Although the national utility does not directly have the funds to increase its shareholding further, the government is still trying to buy back the remaining shares in the plant from the foreign sponsors. The original sponsor, CMS, subsequently sold its shares to TAQA but was severely criticised by the Ghanaian government for not giving it first option. This ongoing spat has further compromised the investment climate for IPPs in Ghana (GGEA, 2008; Yeboah, 2008).

In Morocco, the country’s next renewable energy project, a wind farm, will also be developed by ONE, despite the national utility not having adequate financial resources to invest in additional generation plant or to maintain the existing power sector infrastructure. Private investors have stated their interest in wind energy projects if sufficient securities can be provided (CED pers. com., 2006: 1–14), but allocation criteria for such renewable projects are not in the public domain and the absence thereof may dampen interest from potential investors.

Having clear criteria for investments can help to develop a more predictable environment for investors, but what might these allocation criteria be? Various possibilities exist. Where finance is a temporary constraint, government might announce that IPPs will be sought over a specified period and then the national utility will resume responsibility. Or perhaps the national utility has expertise in hydro but not thermal plants and IPPs would explicitly be sought to meet fuel diversity targets. Or government, or the planning authorities, might discuss the 20 year power expansion plan with the national utility and agree up front which options it would take responsibility for and which would be bid out to the private sector. The point here is not so much the actual allocation criteria themselves, but rather that there is a transparent allocation of responsibilities that creates a clearer and certain investment opportunities for IPPs. Transparency in allocation criteria also implies that the incumbent national utility knows what its own responsibilities are. The split in responsibilities between the national utility and IPPs obviously also needs to be backed by strong and consistent political leadership and state action.

2.3. Generation contracting

In most cases, IPP contracts extend over a long period of time and typical contracts can range from 15 to 30 years. The length of the contract is considered both a strength and a weakness: a predictable revenue stream allows equity risk capital to be rewarded and sponsor’s can also service debt with long tenors; conversely, in an environment of liberalisation, 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 (Covidindassyamy, 2005). Whilst all contracts between IPPs and utility off-takers described in this paper have been in the form of long-term PPAs, the legal and regulatory frameworks within which these contracts have been entered have differed resulting in diverse outcomes in each of the countries’ power sectors. These governance frameworks which shape the degree of predictability and risk in the sector, ultimately impact on investment and development outcomes.

2.3.1. IPP charges and payback periods

In the case of Ghana, a number of factors contributed to the relatively high power costs of the Takoradi II IPP. Takoradi II was a 100 per cent equity investment and, thus, had no debt to reduce
the total cost of capital from the reported 20.5 per cent return on equity demanded by the project sponsor, CMS. Additional factors that contributed to increased charges were the deteriorating currency exchange rate coupled with dollar denominated payments to the investor and rising fuel costs, also paid for in hard currency.

IPP in Côte d'Ivoire, Morocco and Tunisia have seen less upward pressure on power charges than was the case in Ghana. Low interest debt, such as the IDA loan that the Ivorian government secured from the World Bank and on-lent to CIPREL, has also helped to reduce PPA charges. Similarly, with Azito, the partial risk guarantee (PRG) from the World Bank for the loan syndication from commercial banks reduced the cost of capital. The Government of Côte d'Ivoire also offered a sovereign guarantee resulting in more favourable terms for the loan agreements.

Almost all debt for IPPs in Côte d'Ivoire, Morocco and Tunisia is heavily loaded in the first years of operation. Contracting arrangements between off-takers and IPPs, therefore, require charges paid to IPPs to be higher than the average price per kWh in the early years of the contract. When IPPs are required to come on stream in quick succession, payments can increase to levels that strain the cash flow of off-taker utilities, even if the average price for the power generated for the contract duration is considered competitive. When off-takers are experiencing cash flow problems, it is difficult to attract additional generation. Morocco is an example of where three IPPs were developed within five years, with collective payments to IPPs reaching a peak at the end of year five, severely impacting on one's profitability.

The above examples emphasise just some of the complexities in contracting IPPs effectively and competitively. The immediate implication is that government and national utilities require a great deal of specialised expertise in order to negotiate robust and competitive contracts. Private sponsors will often hire the best legal, financial and technical transaction advisors. Governments too need good people on their side of the table. Unfortunately this is often not the case and governments underestimate the need for specialised transaction advice. The experience of contracting IPPs is relatively new for African governments; most countries have less than a decade of experience and some have none. Once again, experience and collective payments to IPPs reaching a peak at the end of year five, severely impacting on one's profitability.

The above examples emphasise just some of the complexities in contracting IPPs effectively and competitively. The immediate implication is that government and national utilities require a great deal of specialised expertise in order to negotiate robust and competitive contracts. Private sponsors will often hire the best legal, financial and technical transaction advisors. Governments too need good people on their side of the table. Unfortunately this is often not the case and governments underestimate the need for specialised transaction advice. The experience of contracting IPPs is relatively new for African governments; most countries have less than a decade of experience and some have none. Once again, this points to an area where hybrid power markets present new challenges that have to be dealt with consciously and purposefully. As with planning, contracting is not a trivial exercise. Governments need to allocate clear responsibility to either the national utility or a government agency to undertake this function. If the national utility is to be responsible, then it is also critical that a ring-fenced contracting function is established separate from the utilities own generation or new build function—to avoid any conflicts of interest. Perhaps the best location is an independent system operator which also takes responsibility for planning which can then be integrated with the procurement function. In this case the system operator takes responsibility not only for short term balancing of the system but also long term security of supply.

In the four country cases examined, only two countries have de jure electricity regulators—Ghana and Côte d’Ivoire. However, neither of these regulators were present or played a significant role in the development of the IPPs in their respective countries. An analysis of regulatory and governance functions in these four case studies suggests that the presence or absence of formal regulatory institutions has had little impact per se on the countries’ abilities to attract sufficient generation capacity; instead, analysis of the data suggest that the extent to which de facto or de jure regulators have acted in a credible, transparent and consistent manner is important. In effect, it is the governance role that regulators (whether independent, or within government) play in ensuring transparency and predictability that helps to attract adequate investment in generation.

In the case of Ghana, the Public Utilities Regulatory Commission (PURC) was instituted only after the Takoradi II IPP deal had been finalised. In its ex post review of the PPA, the PURC suggested that part of the capacity charge should become a government contingency; however, since the financial closure of the project had already taken place, there was little that the regulatory review could do to alter the charges from the sponsor.

In Ghana, the responsibilities for technical and financial regulation have been split between two separate entities, the Energy Commission and the PURC as the government did not want a single agency that would become too powerful (Energy Commission pers. com., 2007). It would appear that this sentiment has led to the government undermining the PURC’s mandate on a few occasions. Although PURC is legally mandated to be impartial in its operations, it is still dependant on the government for funding, raising questions about its independence. In some cases, PURC has succeeded in raising tariffs but the government has hampered its efforts to have cost-reflective tariffs by changing the tariff structure and increasing the band of the lifeline tariff. The resignation of the PURC chairman in 2007 is an illustration of the frustration that regulators, as well as other stakeholders in the power sector, experience due to political meddling and related setbacks which detract from the objective of making the sector more sustainable and attracting further investment. A decade after the PURC has been instituted, the power sector is still subsidised by the government, which, on numerous occasions, has promoted short-term political interests ahead of power sector sustainability.

The split in responsibilities between PURC and the Energy Commission presents a number of potential contradictions and difficulties in procuring new power. The one agency is responsible for licensing new generation plant (and hence market entry) while the other is responsible for approving tariffs, including approval of pass-through provisions from the PPA through to captive customers. In this situation, there is the risk of one agency approving the entry of an IPP and the other effectively torpedoing the investment by not approving the tariff. This experience would indicate that a single, integrated regulatory function is preferable.

In Côte d’Ivoire, as in the case of Ghana, the regulator, ANARE, only became effective after the agreements for the two IPPs had already been finalised. Unlike PURC, however, ANARE has no tariff setting powers and its function is merely to monitor the various activities of operators in the power sector and to mediate between consumers and operators, as it protects the interests of consumers. It also plays an advisory role to the Ministry of Energy. Although ANARE would like to see its mandate expanded to include tariff setting, there is currently no plan by the Ministry of Energy to do so (ANARE pers. com., 2007). ANARE’s sister institutions, SOGEPE and SOPIE provide oversight of, amongst other issues, the financial and the technical performance of the sector. Since the inceptions of reforms, revenues have at least covered the cost of production. As there are only private operators
in the sector, which are mainly regulated by contracts, the role of the state has been reduced to oversight and planning more than in any of the other countries evaluated in this paper. Thus the nature of the “hybrid” power market is very different in Côte d’Ivoire. While the national utility’s assets remain public and the overall governance of the utility is controlled by state institutions, day-to-day management and operations are in private hands. The country has therefore few of the contradictions which potentially arise in other hybrid markets where the state-owned and managed national utility often frustrates the entry of the private sector. It may be argued that Côte d’Ivoire’s arrangement has contributed to improved governance and regulation in the power sector, since the government is less inclined to be drawn into operational issues and can focus on its governance and oversight mandate.

Ghana’s experience is quite different. The state-owned utility, VRA, has frustrated the entry of IPPs. It did not agree to the proposed Ashanti/KMR plant selling excess capacity to VRA customers. The negotiations for this IPP also failed because VRA wanted to charge an excessive wheeling fee for the power.

The presence of three electricity governance agencies in Côte d’Ivoire does not create the same contradictions as the dual regulators in Ghana, since their roles are more distinct and clearly defined. ANARE acts as an arbitrator and mediator between actors in the sector, SOGEP E manages the sector finances and provides input into the tariff setting process, and SOPIE does long-term strategic planning (including generation procurement) in the power sector. The Ministry of Mines and Energy still has overall responsibility for the power sector. It sets tariffs and approves plans for investment and hence the three state agencies do not perform their functions in isolation, but work coherently toward the achievement of common shared objectives.

The three entities in Côte d’Ivoire perform their respective functions under a specific legal framework (where financial equilibrium or viability is mandated as a key sector priority). Unlike PURC and the Energy Commission in Ghana, where tariff setting and licensing are separated, these functions are undertaken by the Ministry of Energy in Côte d’Ivoire.

In Morocco, the absence of a regulator during the reform process does not appear to have impacted negatively on investment during the first decade of power sector reforms, i.e. from 1994 to 2004. However, the development of generation infrastructure appears to have been inadequate for the period commencing in 2005, as tariffs have not kept up with the cost of production, thereby creating financial difficulties for the national utility, ONE.

In some industrialised and developing countries, it has been found that if SOEs report to both the sector ministry and the Ministry of Finance, there is increased oversight of the SOE’s finances as social and financial objectives are clearly separated and managed. In both Côte d’Ivoire and Tunisia, the Ministry of Finance provides input to the setting of tariffs with the mandate of ensuring the financial sustainability of the sector. In the case of Morocco, however, the participation of the Ministry of Finance in the power sector through tariff setting does not appear to have yielded similar results, suggesting that social and political considerations played a larger role in this sphere than financial and economic considerations.

Tunisia, on the other hand, has seen consistent tariff increases reflecting the increasing cost of fuel and power production over the three years to 2008. Despite not having an independent electricity regulator, the government, as the de facto regulator, has demonstrated commitment to supporting the financial health of the power sector. These tariff adjustments, however, have not come without counter pledges from the utility. STEG has improved its worker productivity and technical efficiency. Tunisia stands out among African countries as one that has seen few problems in the development of its IPPs, with almost seamless coordination between IPP sponsors, STEG and the Ministry of Industry and Energy.

In summary, the data suggest that the issue of whether one has ‘independent’ regulators or whether these functions are embedded in the state is not as important as to whether these governance and regulatory functions are undertaken with a strong political commitment to the financial sustainability of the sector and a commitment to bring in private sector investment. The case of Tunisia, which has probably been the most successful of all African countries in its generation investment programme, would seem to indicate that a crucial contributing factor is strong, purposeful political leadership and integrated governance, where the national utility is not only aligned to government policy but becomes and effective instrument in government realising that policy—for example in planning, procurement and contracting of IPPs.

Finally the issue of the single-buyer needs to be addressed. Most countries have allocated this function to the incumbent utility which is able to aggregate demand and sign PPAs with IPPs. Prices for IPPs are generally higher than the average tariffs charged to customers by the national utility and thus consumers will preferentially buy from the utility rather than directly from the IPP. However, there will inevitably be exceptions. Some large industrial and mining customers value reliability of supply and may be prepared to pay a premium. Thus countries should be cautious in allocating an exclusive buying function to the national utility and rather mandate a non-exclusive central purchasing function while fostering customer choice, at least for large qualifying customers who should be permitted to negotiate directly with both domestic and cross-border IPPs. Similarly, IPPs should be granted the freedom to negotiate contracts with any willing buyer, both domestically and across borders.

3. Conclusions and implications for power sector reforms

To recap, the standard model of power sector reform was intended to introduce unbundling, privatisation and competition into the ESI, as well as independent regulatory oversight. The introduction of private capital through IPPs was seen as an important step in these reforms and could provide almost immediate relief to power systems that were short of capacity. The general notion that this was widely held was that the private sector could procure, develop and operate generation assets more efficiently than the public sector. Private sector-led investment and operation, therefore, was expected to roll back the consequences of decades of inefficient state-led development and operation.

While a few cautionary voices warned against the transferability of the proposed reforms, and how their success was strongly linked to their problem contexts, the reform message spread as it was advocated by development finance institutions, international policy consultants, and, in some cases, domestic champions (Gratwick and Eberhard, 2008). Legislation was enacted to make provision for the reforms, state-owned utilities were corporatised, electricity regulators were established, and IPPs were introduced.

It is now apparent that nowhere in Africa are fully unbundled, private or competitive electricity markets to be found. Power sector reform in Africa, and in many other developing countries, has resulted in what is defined in this paper as hybrid power markets, where state-owned utilities and IPPs operate side by side with virtually no competition between generators, in contrast to what was espoused by the standard model of reform.
Hybrid generation markets consisting of state-owned utilities and IPPs are expected to be around at least for the foreseeable future. Many countries have jettisoned the drive to move towards the standard reform model, and those that have not, are finding out how difficult it is to progress towards it.

In the case of Ghana, competition in generation has not been realised as intended. Even in Côte d’Ivoire, which has hardly any state-involvement in the day-to-day operation of the utility, attainment of the standard model has not been achieved. In Morocco, too, the implementation of a dual market that was proposed as a transition toward a competitive market (Jerjini, 2002), has seen numerous delays. Tunisia has reverted to mostly public-funded plants operated by the national utility, STEG, after having developed only one large-scale IPP.

Given that, in all probability, competitive generation power markets in Africa, and many other developing countries, will not be realised as intended, at least in the foreseeable future, and if the de facto situation is a hybrid market, a key question to be addressed is: how can they be made to work so that the original objectives of increased investment and more efficient operation are obtained?

It is clear that explicit attention needs to be given to planning, procurement and contracting issues. Responsibility needs to be allocated for flexible and dynamic generation expansion planning. Clear criteria need to be developed whereby opportunities for new build are allocated between the incumbent SOE and IPPs. Institutional responsibility needs to be allocated for procurement of new capacity and the timely initiation of international competitive bidding processes. Or if unsolicited bids are inevitable, clear criteria and processes need to be developed for their assessment. Responsibility needs to be allocated for contracting, preferably via a non-exclusive, central purchasing function linked to an independent system operator and/or transmission company. And clear rules need to be established for fair dispatch of utility versus IPP generators. Many of the above points might seem obvious. Yet, what this paper has shown is that they are often neglected.

Hybrid power markets are the de facto result of power sector reform in Africa and many other developing regions. This has profound implications not only for the way we think about power sector reform but also where further reform efforts are directed. It would now seem inappropriate, even futile, to retain the standard reform model or to measure power sector reform progress in terms of how many of the elements of the standard model have been obtained. The standard model is no longer the normative option or end goal. Much more productive is to recognise the reality of what power sectors actually look like in Africa and elsewhere and to respond to the specific challenges that emerge from these hybrid markets.

State-owned enterprises are probably here to stay and thus SOE reform remains an imperative, even more so now that effective SOEs are crucial to the successful operation of hybrid markets, not only in the areas highlighted above (planning, procurement and contracting) but also in being credible off-takers for IPPs.

Some of the efforts of the 1960s, 1970s and 1980s to reform SOEs are being revisited (Irwin and Yamamoto, 2004; Nellis, 2005; Gómez-Ibáñez, 2007; Vagliasindi, 2008). Two broad categories of reforms remain relevant. First, roles and responsibilities need to be clarified. We have highlighted a number of these responsibilities with regard to state-owned utilities’ roles in facilitating investment in new generation. But there are number of core roles and functions in the governance of SOEs which need clarification, including balancing governments’ different roles of ownership, meeting social needs and regulation. Clear sector policies, transparent transfers for social programmes, the establishment of independent regulators and formalisation of ownership responsibilities through appropriate legislation, corporatisation, performance contracts and effective monitoring units, remain key aspects of reforms aimed at improving the performance of SOEs.

A second category of reforms involves what Gomez-Ibáñez (2007) refers to as “changing the political economy of SOEs”. By that he means strengthening the interests of stakeholders who have an interest in more commercial behaviour by the SOE. This can be achieved by improving the quality and transparency of information, and benchmarking, thus creating pressures from tax payers and consumers for improved performance. In addition, promoting mixed capital enterprises, either through private debt raising, or through partial floating of equity on stock exchanges, creates an additional constituency of bond holders, investors and rating agencies, all interested in improved utility performance.

Hybrid power markets thus give rise to new challenges. A renewed effort has to be made to improve the performance of SOEs. Attention also has to be given to the many planning, procurement and contracting functions previously undertaken within vertically integrated, state-owned national utilities which are now neglected or poorly performed by other institutions. The overlapping insights from state-involvement in hybrid power markets require explicit and purposeful policy actions to deal with these planning, procurement and contracting challenges in order to attract sufficient new investment in generation capacity and private sector participation in the power sector in Africa.

References


