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**POWER SECTOR REFORM IN AFRICA:
THE PARADOX OF HYBRID MARKETS**

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Thesis Presented for the Degree of Doctor of Philosophy

University of Cape Town

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February 2009

DECLARATION

I declare that this thesis is my own unaided work, both in concept and execution. Neither the substance nor any part of this thesis has been submitted for a degree at this university or at any other university.

Signature _____

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Date _____

University of Cape Town

ACKNOWLEDGEMENTS

The completion of this thesis would not have been possible without the support and kindness that I have received from so many people and institutions. My heartfelt is expressed to them for their efforts and encouragement.

Anton Eberhard, my supervisor, for his intellectual guidance given throughout the duration of this learning journey.

Katharine Gratwick, for her guidance during the investigations of the empirical cases for this thesis.

Sharman Wickham, for her kindness and timely reviews of the thesis chapters and offering useful suggestions for structuring and improving the writing of this thesis.

The Management Programme in Infrastructure Reform, for providing the funding to carry out the empirical work for this thesis.

Nuroo Ismail from the Knowledge Commons, UCT Libraries, for her kind assistance in formatting this thesis.

My employer, Eskom, for allowing me the time off to complete the writing of this thesis.

To all the stakeholder respondents and interviewees, who have graciously responded to a seemingly endless stream of questions and follow-up queries related to issues in their respective power sectors.

My parents, who have directed my paths in my youth.

Yolanda, my wife, for her gentle understanding and support; as well as my children, Amy, Jodie, and Joshua, for making life worth the living.

Let the wise listen and add to their learning, and let the discerning get guidance –

Proverbs 1:5

ABSTRACT

For many countries in Africa, power sectors are characterised by insufficient generation capacity. Due to poor financial and operational performances, many state-owned utilities have had inadequate financial reserves to invest in additional generation capacity. Governments, too, have experienced difficulty in financing generation expansions as a result of the reduction in loans from traditional financiers of infrastructure. Reforms to address poor performances in the 1990s, in part, focused on introducing private sector participation to the power sector at the generation level through independent power projects. It was anticipated that independent power producers would provide benchmarks for state-owned utilities and enable longer term power sector efficiency. Reform in this sector followed a prescribed evolution towards power markets that would allow wholesale competition amongst generators and so lead towards efficiency improvements. Despite reforms being embarked on in many African states, 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 thesis 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. The thesis identifies and describes the factors that have contributed to a lack of investment and shortages in generation capacity in hybrid markets exploring how policy, regulatory and institutional frameworks have contributed to this situation. It also investigates how planning and procurement challenges have led to difficulties in adding sufficient generation capacity in a timely manner, exacerbating the problem of insufficient generation capacity in Africa. Finally, the dissertation 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.

LIST OF ACRONYMS

ABB	Asea Brown Boveri
AFD	Agence Française de Développement
AKFED	Aga Khan Fund for Economic Development
ANARE	Autorité Nationale de Régulation du secteur de l'Electricité
BCEAO	Banque Centrale des États de l'Afrique de l'Ouest
BCP	Banque Centrale Populaire
BG	British Gas
BMCE	Banque Marocaine pour le Commerce Extérieure
BNETD	Bureau National d'Etudes Techniques et de Développement
BNP	Banque Nationale de Paris
BOAD	Banque Ouest Africaine de Développement
BOO	Build-Own-Operate
BOOT	Build-Own-Operate-Transfer
BRP	Bureau de Recherché Pétrolières
BTO	Build-Transfer-Operate
c	cent
CAA	Caisse Autonome d'Amortissement
CCGT	Combined Cycle Gas Turbine
CDC	Commonwealth Development Corporation
CDER	Centre de Development d'Energie Renouvelable
CED	Compagnie Eolienne de Detroit
CEGB	Central Electricity Generation Board
CEO	Chief Executive Officer
CFA	Communauté Financière d'Afrique
CFL	Compact Fluorescent Lamps
CIE	Compagnie Ivoirienne d'Electricité
CIPIE	Commission Interdépartementale de la Production Indépendante d'Electricité
CIPREL	Compagnie Ivoirienne de Production d'Electricité
CMS	Consumer Michigan Services
CNCA	Caisse Nationale du Credit Agricole
CNR	Canadian Natural Resources
CO₂	Carbon Dioxide
COD	Commercial Date of Operation
CPC	Carthage Power Company
CSPIE	Commission Supérieure de la Production Indépendante d'Electricité
DDO	Distillate Diesel Oil
DEAT	Department of Environmental Affairs and Tourism
DEEN	Direction de l'Energie Electrique et des Energies Nouvelles
DEG	Deutsche Investitions- und Entwicklungsgesellschaft
DFI	Development Finance Institution
DIP	Direction Investissements Publics

DME	Department of Minerals and Energy
DMP	Direction des Marchés Publics
DPE	Department of Public Enterprises
DSM	Demand-Side Management
€	euro
ECG	Electricity Company of Ghana
EDF	Electricité de France
EECI	Energie Electrique de Côte d'Ivoire
EEM	Energie Electrique du Maroc
EET	Energie Electrique de Tahaddart
EFG	Energy Foundation of Ghana
EIA	Environmental Impact Assessment
EIB	European Investment Bank
ENDESA	Empresa Nacional de Electricidad S.A.
EPA	Environmental Protection Agency
EPC	Engineering Procurement and Construction
EPRI	Electric Power Research Institute
ERG	Export Risk Guarantee
ESB	Electricity Supply Board
ESI	Electricity Supply Industry
ETAP	Entreprise Tunisienne d'Activités Pétrolières
FDI	Foreign Direct Investment
FERC	Federal Energy Regulatory Commission
FMO	Financierings-Maatschappij voor Ontwikkelingslanden
FNEE	Fonds Nationale de l'Energie Electrique
GDF	Gaz de France
GDP	Gross Domestic Product
GE	General Electric
GHC	Ghanaian cedi
GMT	Greenwich Mean Time
GNPC	Ghana National Petroleum Company
GPE	Groupe Projet Energie
GSPER	Groupement Spécial Pour l'Electrification Rurale
GTZ	Gesellschaft für Technische Zusammenarbeit
GW	Gigawatt
GWh	gigawatt hour
HFO	Heavy Fuel Oil
HVO	Heavy Vacuum Oil
ICB	International Competitive Bid
IDA	International Development Association
IFC	International Finance Corporation
IMF	International Monetary Fund

IPP	Independent Power Producer / Project
IPS	Industrial Promotion Services
IRP	Integrated Resource Planning
JBIC	Japan Bank for International Cooperation
JLEC	Jorf Lasfar Energy Company
KfW	Kreditanstalt für Wiederaufbau
KNUST	Kwame Nkrumah University of Science and Technology
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
£	British Pound
LCO	Light Crude Oil
LNG	Liquefied Natural Gas
LPG	Liquid Petroleum Gas
LRMC	Long Run Marginal Cost
MAD	Moroccan dirham
MDG	Millennium Development Goals
MIGA	Multilateral Investment Guarantee Agency
MIR	Management Programme for Infrastructure and Regulatory Reform
MoU	Memorandum of Understanding
MT	Metric Ton
MW	megawatt
NED	Northern Electricity Department
NES	National Electrification Scheme
NGO	Non-Governmental Organisation
O&M	Operating and Maintenance
OECD	Organisation for Economic Co-operation and Development
OEM	Original Equipment Manufacturer
ONE	Office Nationale de l'Electricité
OPEC	Organisation of Petroleum Exporting Countries
OPIC	Overseas Private Investment Corporation
PERG	Programme d'Electrification Rurale Global
PESD	Program on Energy and Sustainable Development
PETROCI	Société Nationale d'Opérations Pétrolières de la Côte d'Ivoire
PPA	Power Purchase Agreement
PPI	Private Participation in Infrastructure
PRG	Partial Risk Guarantee
PRGF	Poverty and Growth Reduction Facility
PROPARCO	Promotion et Participation pour la Coopération économique
PSEG	Public Service Enterprise Group

PSRC	Power Sector Reform Committee
PURC	Public Utilities Regulatory Commission
PURPA	Public Utility Regulatory Policies Act
REE	Red Eléctrica de España
RfP	Request for Proposal
RfP	Request for Proposal
ROE	Return on Equity
ROR	Rate of Return
S&P	Standard & Poors
SACE	Servizi Assicurativi del Commercio Estero
SAP	Structural Adjustment Programme
SAUR	Société d'Aménagement Urbain et Rural
SEEB	Société d'Electricité d'El Biban
SIIF	Société Internationale d'Investissements Financiers
SODECI	Société de Distribution d'Eau de Côte d'Ivoire
SOE	State Owned Enterprise
SOGEPE	Société de Gestion du Patrimoine du Secteur de l'Electricité
SONEL	Société Nationale d'Electricité de Cameroun
SOPIE	Société d'Opération Ivoirienne d'Electricité
SPV	Special Purpose Vehicle
STEG	Société Tunisienne de l'Electricité et du Gaz
TANESCO	Tanzania Electricity Supply Company Limited
TAQA	Abu Dhabi National Energy Company
TERNA	Technical Expertise for Renewable Energy Application
TICO	Takoradi International Company
TND	Tunisian dinar
TOPL	Tema Osonor Plant Limited
TWh	Terawatt hour
UEMOA	Union Économique et Monétaire Ouest Africaine
UK	United Kingdom
US ExIm	US Export Import Bank
US\$	United States Dollar
USA	United States of America
VALCO	Volta Aluminium Company
VAT	Value Added Tax
VRA	Volta River Authority
WAGP	West African Gas Pipeline
WTO	World Trade Organisation
ZESA	Zimbabwe Electricity Supply Authority
ZIMCO	Zambia Industrial and Mining Corporation

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CHAPTER 1

INTRODUCTION

Power sector reform, undertaken across developing regions over the past two decades, and driven by the need to improve sector performance and attract new investment, has led to a largely unexpected consequence. Instead of a new market model, characterized by competitive wholesale and retail electricity markets, what presently predominates is a hybrid market, where state-owned generators and independent power producers co-exist. These hybrid markets present a host of challenges, including the need to create alternative policy, regulatory and institutional frameworks, which unless addressed, may impede further investment into the sector.

1.1 Background and Focus

1.1.1 Africa's Chronic Power Problems

Compared with other developing regions, the power sectors of most African countries are relatively more undeveloped, characterized by insufficient generation capacity, high costs, poor reliability and service quality, and low access rates.

Generally, Africa has low levels of installed generation capacity. Installed power generation per capita in Africa, is less than 40 per cent of Asia, and about a fifth of South America (EIA 2005).¹ With growth rates in capacity additions lagging the rest of the developing world during the last three decades, the gap between Africa and the rest of the developing world has continued to widen.

The electrification rate in Africa is two to three times lower than the average rate of developing regions, and for rural areas electrification rates are three times less than the average for all developing countries (IEA 2006). Roughly a quarter of Sub-Saharan Africa's population has access to electricity with connection rates as low as 5 per cent in rural areas for

¹ For a larger perspective, installed generation per capita in Sub-Saharan Africa (excluding South Africa) is less than one twentieth of the Organisation for Economic Co-operation and Development (OECD), and less than one thirtieth than that of the United States of America (USA) (EIA 2005).

some countries (Cosgrove-Davies 2006). Since 1990, the East Asia, Latin America, and Middle East developing regions have all increased their access rates by at least 20 per cent, while due to population growth and household formation exceeding new connections, overall access levels in Sub-Saharan Africa are declining (Eberhard, Foster et al. 2008:4). If this trend continues, fewer than 40 per cent of Sub-Saharan African countries will have universal access to electricity by 2050 (Banerjee, Diallo et al. 2007).

Low access levels may in part be attributed to affordability of power. The average residential power tariff in Sub-Saharan Africa is about double the average of other developing regions (Eberhard, Foster et al. 2008). This is due to a number of reasons. National power systems are typically small. Hence, African power sectors do not benefit from the economies of scale that bulk generation offers. Excluding Algeria, Egypt, Nigeria and South Africa, no African country has an installed capacity greater than 6000 megawatts (MW) (EIA 2005). Countries that are not endowed with sufficient primary energy resources face the reality of even higher power costs as expensive fossil fuels are imported. Large network losses in inefficient power systems exacerbate the problem. And finally, low population densities raise the cost of extending electricity networks.

Actual costs are even higher for African consumers when, due to poor reliability of the power systems, the cost of back-up generation is factored into the equation. In Kenya, Nigeria, Tanzania and Uganda, more than 80 per cent of large companies depend on their own sources of back-up generation because power networks are unreliable, pushing the price of power up (Estache 2005:31). In Benin, back-up generation more than doubles the weighted average cost of power (Eberhard, Foster et al. 2008:12).

Power shortages have also led governments to contract short-term emergency power from private power companies. Although such projects may be up and running within a matter of months, a key drawback is that they are comparatively expensive, generating power at a cost of US\$0.20-0.30 per kilowatt-hour.

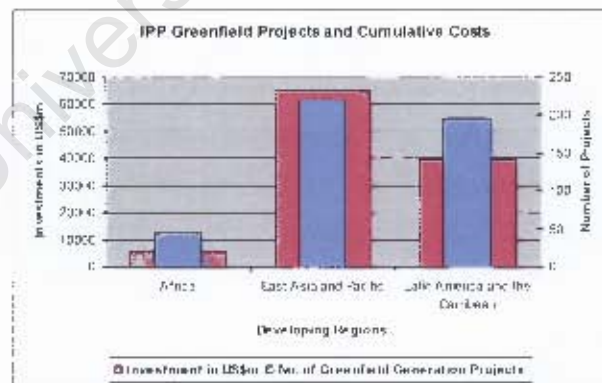
Notwithstanding the costly option of rental power to make up for electricity shortages, power outages are still endemic to Africa. The average number of power outages for a typical month is high in Africa, with Guinea and Malawi reporting 34 and 77 outages per month in 2006

respectively (World Bank 2007).² The average number of monthly outages for Sub-Saharan Africa is more than three times the average of Eastern Europe and Central Asia, and Latin America and the Caribbean (World Bank 2007). Inadequate electricity capacity comes at a huge cost to the economies of these countries and also undermines the achievement of the Millennium Development Goals (MDGs).

A key reason for capacity shortages is insufficient investment in generation infrastructure.³ Many utilities are unable to finance investment off their balance sheets as tariffs barely cover operating and maintenance costs (Eberhard, Foster et al. 2008). Large transmission and distribution losses, incurred due to load centres being far from generation, coupled with electricity theft, translate into revenue losses for utilities. Poor billing and collection rates have impacted on investment, and also have led to inadequate maintenance of existing facilities.

Official development assistance has been inadequate to plug the financing gaps. Although private sector investment has helped to alleviate capacity shortages over the past two decades, this has not been enough. Furthermore, in Africa, private investment lags that of other developing countries as shown in Figure 1.1.

Figure 1. 1: A Comparison of Private Investment in Generation in Developing Regions (1990-2007)



Source: Author's compilation based on the World Bank PPI Database (2008a)

² As a result, in Guinea and Malawi about 60 per cent and 50 per cent of firms own or share generators, respectively.

³ Price Waterhouse Coopers (2005:7) conducted a global survey of what utilities considered as the attributable causes of recent energy supply issues. The overwhelming response was the lack of capacity in infrastructure investment, which was attributed to the lack of investment.

The poor investment climates in African countries and the continued weak states of power sectors result in governments often having difficulties in attracting capital to finance expansion. In addition to the abovementioned impediments, droughts, financial shocks affecting energy costs and exchange rates, and political conflict, among others, have all impacted the power sectors of African states to some extent, thereby affecting investment.

1.1.2 Power Sector Reforms

In many African states, reforms were embarked upon to improve the functioning of power sectors, and more specifically state-owned utilities, in part by attracting increased investment into the sector. Acutely aware of the need to change and gear policies to recover from sector malaise, governments often, with the assistance of external consultants, implemented strategies to enhance performance. This was generally prompted by development finance institutions, the principal lenders to African power sectors. In the early 1990s, the World Bank and other multilateral and bilateral financial institutions recommended specific new policies to improve sector performance. The objectives of these policies were; to promote increased financial and technical efficiency in utility operations; to reduce the financial and administrative burdens that utilities impose on the state; to reduce the level of debt assumed by government from the power sector; and to reduce the cost of electricity by subjecting the generation and distribution sub-sectors to competitive market forces (World Bank 1993).

Development finance institutions were supportive of programmes towards the establishment of transparent regulatory processes and legal frameworks that would support power sector restructuring. It was believed that such frameworks would instil investor confidence and facilitate competition among suppliers by establishing, among other things, institutional structures to more clearly define government's role as policy maker, instead of power producer. In the same vein, utilities were called upon to corporatise and operate on commercial principles to create autonomous entities that manage their own budgets, procurement, as well as staff benefits. Corporatisation and commercialisation were marked as the first steps to attract private sector participation (World Bank 1993).

Private participation was initially prescribed at the generation level through independent power producers (IPPs). Private investment in generation was aimed at reducing the cost of power through competition in the sector. Mindful of the fact that investors would seek assurances for market risk, these projects would be on a Build-Own-Operate (BOO) or Build-Own-Operate-Transfer (BOOT) basis with Power Purchase Agreements (PPAs) to assure

revenues. Later it was intended that competition would exist between generators in an electricity market to bid and sell power on to customers through a transmission company or directly to large consumers (World Bank 1993).

Despite many African countries initially embarking on the reform prescriptions, little reform has actually taken place. Although some of the reform steps were implemented in countries that assumed restructuring policies, most power sectors remain vertically and horizontally integrated with IPPs operating at the fringes in generation.⁴ In many countries state-owned utilities have resumed responsibility for additional capacity expansions, instead of the private sector as initially planned. In some cases, challenges in attracting private investment have left many governments and power sectors abandoning the road of reform, and in other cases the initial drivers for reform have eased, thereby lending support for increased state participation.

Difficulties in implementing the entire suite of power sector reform steps up to and including competition at the generation and the distribution levels have left African power sectors in an intermediate state. What has emerged is an alternative model whereby power sectors are between the old vertically integrated, state-owned structure and the intended competitive market structure.

1.1.3 The Challenges of Hybrid Markets

In the face of fragmented and stalled reforms, new investments have occurred largely in the form of IPPs, resulting in hybrid markets, as state-owned utilities and IPPs now co-exist in the sector. Although IPPs represent an important new source of investment, problems of insufficient capacity still persist. To date, experience in Africa has shown that hybrid markets face their own set of challenges and paradoxes in securing adequate generation investments. Despite hybrid markets presenting an opportunity for private sector investment, unattractive conditions and negative experiences in some countries have led to diminished private sector involvement. Also, regardless of reforms aimed at improving economic performance objectives, such as cost recoverable tariffs, most experience has shown that these initiatives have proven difficult to implement and maintain. While there is a need to achieve economic sustainability in African power sectors, steep increases in fuel costs and high inflation have undermined efforts to facilitate mutually beneficial investments over the long-term. In

⁴ The exceptions are Côte d'Ivoire, Morocco, and Tanzania (depending on hydrological conditions), where more than 50 per cent of power is produced by IPPs (as of 2007).

addition, despite the need for flexibility in such unstable economic environments, long-term PPAs generally lock in fixed charges for up to thirty years.

Power sector planning involves critical linkages between power sector data collection agencies, planning agencies, fuel suppliers, utilities, various interest groups and stakeholder institutions, regulatory agencies, licensing agencies, developers, insurers, and environmental agencies, amongst others. As part of reforms, planning and contracting, in numerous cases, has moved from the state owned utility to the Ministry of Energy or a related agency set up to administer these functions without due consideration for devising robust contracting processes or adequate skill to staff these departments. As a result, planning has often failed to encompass the complexities involved in contracting new capacity, leading to extensive delays in developing these projects, and making load-shedding inevitable.

In many cases SOEs undermine private investment by dragging their heels in engaging and contracting private power. Important stakeholders to the agreements signed by the IPPs, they act as off-takers of power and therefore have to agree to the terms of the PPA, often contesting the higher charges that new investments bring compared to their own plants where capital has been depreciated or where tariffs do not reflect the true cost of power. In many countries “IPP” goes hand in hand with increased costs, and consumers often get behind the state-owned utility in lobbying to build new plants and expand their power base and turf.

In Africa, there is little evidence of clear and transparent criteria for the allocation of new-build opportunities amongst state-owned utilities and IPPs. Procurement policies are often inadequate and contracting frameworks often lack certainty and transparency resulting in lengthy and confusing negotiations and even allowing opportunity for corruption. Weak or lacking regulatory and governance frameworks erode the credibility of investment and contracting decisions and there is often no clear linkage between planning and the timely initiation of competitive tender processes.

This thesis examines the new challenges that arise in hybrid power markets in Africa. It evaluates how policy, regulatory, and institutional arrangements might respond to such markets and addresses how specific challenges may be overcome to enhance the performance of the power sector.

1.2 The Research Questions

Power sector reforms were formulated in part to address the problems of insufficient electricity capacity. In Africa, however, reforms have not unfolded as planned. Instead, what has transpired as a result of initial reform efforts is a hybrid market in generation made up of the incumbent state owned utility and IPPs.

The dilemma that is analyzed by this thesis is that despite private investment coming into the sector to alleviate the problems of power shortages, a new hybrid market creates its own challenges, which require specific policy, regulatory, planning, institutional and contracting measures.

The thesis will explore the salient features of hybrid markets. The research questions that will direct the inquiry are stated as:

1. To what extent has the emergence of hybrid electricity markets created new challenges to attracting investment into generation capacity in Africa?
2. Have policy, regulatory, and institutional frameworks responded adequately to the special challenges of hybrid markets?
 - Who assumes responsibility for planning in hybrid markets and is planning flexible and dynamic enough for changing market conditions?
 - Have transparent and equitable criteria been developed to allocate new opportunities for generation investment to SOEs and IPPs in a fair manner?
 - Are planning processes explicitly linked to a timely initiation of ICBs?
 - How are unsolicited bids treated / accommodated in the framework?
 - Have explicit and efficient tender, bid and procurement mechanisms been put in place?
 - Do legal and regulatory frameworks create clear and sustainable off-taker contracting arrangements between SOEs and IPPs?
 - Have suitable governance arrangements developed to ensure that single buyer market frameworks operate transparently and clearly?
 - And, do the above create sufficient certainty for potential investors, thereby facilitating new private investment?

3. How could policy, regulatory and institutional frameworks better respond to the challenges of hybrid markets?

1.3 Research Methodology

The literature on power sector reform, state-owned enterprises, IPPs, planning and contracting, guides and informs the analysis of the empirical data in this thesis, which is based on four country case studies.

1.3.1 Research Process

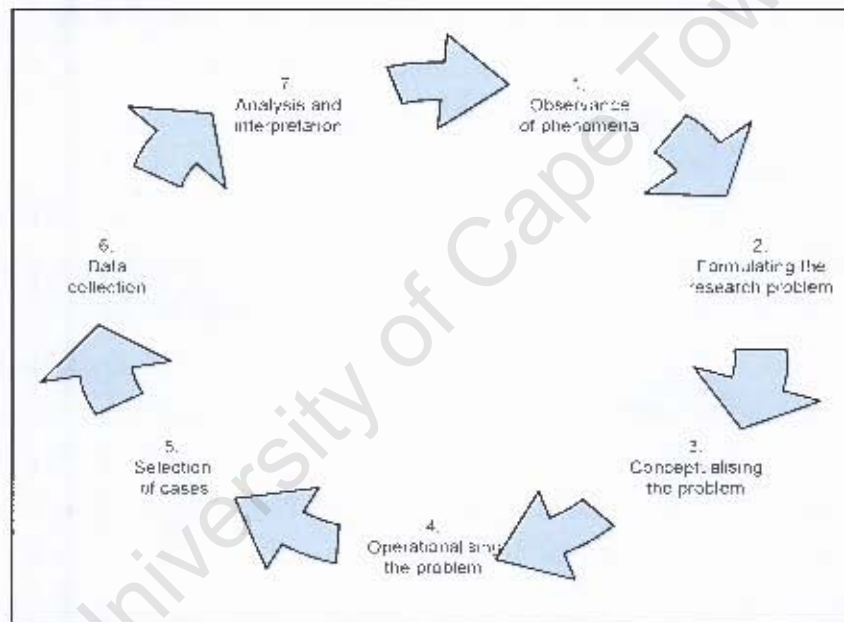
The process adopted to conduct the research follows that of Mouton (1996:65). The main steps that were adopted specific to this research are presented as follows:

- 1) The phenomenon that has been observed in African power sectors is that of poor sector performance due to insufficient generation capacity.
- 2) The problem that this research seeks to address and better understand is why investments in African power sectors have been slow despite reforms aimed to increase investment in generation infrastructure and alleviate capacity shortages.
- 3) Conceptualisation of the problem means embedding the research in a larger body of knowledge. With this in mind, the bodies of literature related to power sector reform, state-owned enterprises, independent power producers, planning and contracting of generation infrastructure were chosen, with the expectation that this would be the main areas of knowledge to which the thesis seeks would make a contribution.
- 4) Once the problem was conceptualised, the research problem could be operationalised. This entails linking the problem to a set of measures to determine the extent to which these measures impact on outcomes. In order to operationalise the problem, the linkages to policy, regulatory, and institutional frameworks were constructed as measures to determine the degree to which these concepts give rise to the problems of insufficient capacity.
- 5) Thereafter the four cases were chosen as select samples of the population of African power sectors and to allow for a contrast of factors that contribute to the problem.

- 6) Next, the data were collected for analysis on the four cases.
- 7) And, finally following the synthesis of the data, the results were interpreted with the view to improve understanding of the observed phenomenon.

The research process was iterative to elucidate a deeper understanding of the problems of insufficient generation capacity. Figure 1.2 gives a graphic illustration of the main stages in the research process, as described above.

Figure 1. 2: Research Process



Source: Adapted by author from Mouton (1996)

A case study approach was adopted to answer the research questions, since the questions seek an array of different kinds of evidence, which is embedded in the case setting (Gillham 2000:2). Evidence was abstracted and collated from the cases to obtain the best possible answers to the research questions. Working inductively from what was found in the case settings, the theory is grounded in the evidence revealed.

1.3.2 The Cases

It should be noted at the outset that this thesis only considers power projects where primarily long-term contracts have been concluded between investors and off-takers. This long-term

Development of large capital projects such as electricity infrastructure involves a wide number of stakeholders, as depicted in Figure 1.3.

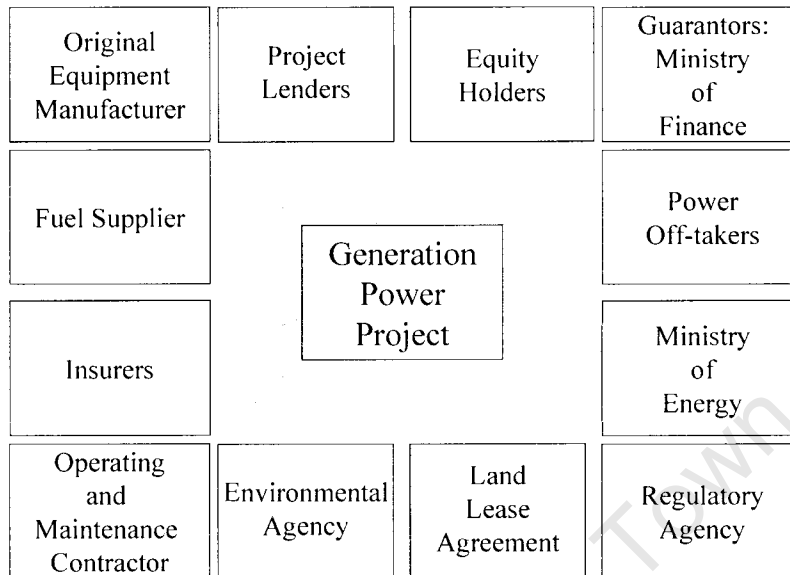
1.3.3 Integrity and Triangulation

arrangement sets the context for evaluating planning of capacity additions; exploring the dynamic nature of investment conditions; and how changes in these conditions affect these projects, and potential future projects, over time. The thesis therefore does not consider short-term emergency rental power to plug shortages. This thesis also only considers greenfield generation investment as opposed to brownfield transactions since greenfield investments by definition imply new generation additions to existing capacity and not simply the transfer of ownership.

Four cases of African power sectors that have had experience with private sector participation at the generation level have been evaluated, namely that of Côte d'Ivoire, Ghana, Morocco and Tunisia. The four countries were selected due to their diverse experiences, which might be consulted to enhance understanding of hybrid markets. Variety in experience was reflected in the: number of projects developed; regional distribution; fuel; duration of investment; level of exogenous shocks and dependence on JPPs.

Two countries are from North Africa and the other two are from Sub-Saharan Africa. Morocco has three projects, Tunisia and Côte d'Ivoire each have two projects and Ghana, despite more than one attempt to contract JPPs, only has one operational JPP. Côte d'Ivoire is interesting in that it has had private participation in its electricity industry since the early 1990s, the first African country to actively embark on reforms involving the private sector. In two of the cases (Côte d'Ivoire and Tunisia), the countries have their own sources of domestic fuel for thermal generation whereas in the other two cases, they have none. Exogenous shocks have impacted the power sectors of both Côte d'Ivoire and Ghana. Furthermore, in these two countries (Côte d'Ivoire and Ghana) hydro generation accounts for significant portions of installed capacity, whereas Morocco and Tunisia have limited hydro generation. Also, in two of the cases (Côte d'Ivoire and Morocco) JPPs account for more than half of national production, in contrast to the other cases where dependence is significantly less. With a combined capacity of just over 3000MW, together these four cases represent about half of the installed JPP capacity on the African continent and hold much relevance for other African countries with hybrid markets.

Figure 1. 3: An Example of key Power Project Stakeholders



Source: Adapted by author from Marais (2006:1) and Naidoo (2006:10-11)

Extensive field work was conducted in each of the countries whereby numerous interviews were conducted with IPP stakeholders, including investor representatives, off-taker utilities, government ministries, fuel suppliers, electricity regulators, transmission system operators, operating and maintenance contractors, equipment procurement contractors, and financial institutions that extended debt to projects. External consultants to the power sectors and academia were also used as sources of data. Data was collected through extensive interviews, observation, records and documents from credible sources; and where possible, data sourced from stakeholders were verified with published sources as well. This approach to data collection required extensive triangulation to assess the veracity of standpoints and, at times, to converge the understanding from the different standpoints. Interim revisions from the four cases were exchanged with stakeholders at least three times to review the drafts and provide comments, and numerous communication (including faxes, email and telephone calls) was part of the effort to produce the case reports over a period of two and a half years. The final drafts of the cases were all verified by stakeholders to accurately depict the experiences with IPPs and power sector reform. Although stakeholder representatives have been the primary source of data for the thesis, due to the sensitivity of the data, their names have been omitted and they are identified only by their organisational affiliation. Much of the data that form the basis for the cases is therefore not cited.

1.4 Structure of the Thesis

This thesis is structured into seven chapters. Following this introduction, Chapter 2 examines the relevant literature. The four cases start with Chapter 3 presenting Ghana's experience with power sector reforms. This is followed by Morocco in Chapter 4, Côte d'Ivoire in Chapter 5 and Tunisia in Chapter 6. The concluding Chapter 7 provides a synthesis of the preceding analysis and reflects on the relevant literature and analytical frameworks, with the ultimate goal of advancing knowledge, and explaining implications for power sector reforms and future investments in the hybrid market.

University of Cape Town

CHAPTER 2

LITERATURE REVIEW: THE CHALLENGES OF HYBRID MARKETS GLOBALLY AND IN AFRICA

Performance improvements in electricity utility SOEs and the emergence of IPPs in developing countries surfaced in the context of power sector reforms which were driven by the need for new investment in improved sector performance. This chapter contextualises hybrid markets within the broader literature on power sector reform to provide a theoretical context for an analysis and understanding of the problem of insufficient generation capacity. Recognition of the two principal actors composing the hybrid market in the generation sector leads to a review of literature on state-owned enterprises (SOEs) and independent power producers (IPPs). Since this thesis investigates the problems of insufficient capacity, literature on planning and contracting generation infrastructure is also reviewed. Combined, these four areas (namely, power sector reform, SOEs, IPPs, planning and contracting) inform and direct the analysis of hybrid markets undertaken in the four case studies included in this thesis.

The sources of literature on power sector reform, SOEs and IPPs referenced in this chapter are from papers published in journals, research reports by academic institutions, as well as country, regional, and global power sector studies commissioned by institutional stakeholders in the power sectors of developing countries, amongst others. The World Bank and other development finance institutions, which have been major financiers of power sector infrastructure in developing countries, have arguably commissioned the most reports on the improvement of infrastructure services since their establishment. The single largest source from which literature has been sourced is therefore from reports commissioned by development institutions such as the World Bank for the sections on power sector reforms, SOEs, and IPPs. While there is a large body of literature on power sector planning, little theory has been forthcoming on the critical linkages between planning and successful commissioning of generation plants as it relates to the narrower problem of insufficient generation capacity. An attempt is made to break out and foreground this area of research in this thesis. Throughout the chapter, where appropriate, examples are highlighted to exemplify the descriptions of the themes presented in the text.

2.1 The Evolution of Power Sector Reform

Power sector reforms were implemented for various reasons in industrial and developing countries. Reform across the globe has, however, always had the achievement of greater efficiency in the provision of electricity as a key objective. In terms of efficiency, the traditional belief was that electricity is a natural monopoly and should remain so in order to benefit from economies of scale in generation and to avoid duplication in distribution. This conventional notion that generation should be a natural monopoly was challenged when technological advances started to make economies of scale in plant construction and operation less important (Smith 1996:26-27; Hunt 2002). The optimal size for generation plant in many instances became smaller, the time for constructing certain technology plants decreased, and an increase in standardisation of plant designs was achieved (Estache and Rodriguez-Pardina 1998:1). Competition thus posed as an attractive option and also helped to address the problem of inefficient investment in (and functioning of) generation plant.

To offer a perspective on how power sectors evolved, this section gives a brief overview of the origins of electricity supply industry (ESI) transformation from state-owned vertically integrated monopolies to reformed power markets. The pioneers of restructuring, namely the United States of America (USA), Chile, England and Wales, and some of the Nordic countries, were the first to test the waters of change and laid the basis for what would later be the blueprint of reform in other industrialised and developing countries. Although the drivers and the paths to reforms amongst the earlier pioneers differed, the reform outcomes were generally regarded as positive. The success of these reformers served as confirmation that electricity may generally be reliably supplied when the supply chain is broken up, while at the same time reducing costs through competition. The successes became a driving force for subsequent reformers to initiate restructuring processes in their own markets to achieve similar benefits.

2.1.1 The Early Reformers: How it all Started⁵

a) USA

In 1978 the United States Congress passed the Public Utility Regulatory Policies Act (PURPA) as part of the National Energy Act to promote greater use of renewable energy (US DOE 1990). Creating a market for non-utility electric power, this law obliged electric utilities to buy power from independent generators at the avoided cost of generation (Hirsh 1999). An outcome of PURPA was the increased prevalence of unregulated independent co-generation plants. Thereafter, a number of states permitted distribution utilities to enter into contracts with IPPs to secure the required capacity for these utilities to serve their customers. In addition to plants that had no connections to traditional utilities, some utilities also set up unregulated subsidiaries to develop IPPs in and outside of their service territories, and, by 1992, IPPs accounted for 60 per cent of new capacity in the USA (Hunt 2002:257). Another event that changed the operation of the sector was the institution of a rule by the Federal Energy Regulatory Commission (FERC) in 1996 requiring that each utility or utility pool allow non-discriminatory open transmission access, thereby paving the way for wholesale competition (Federal Trade Commission 2004). The result was unbundled generation and competition in the sector amongst power producers, nearly twenty years after the PURPA legislation was enacted, with investor-owned generation accounting for about three quarters of US retail electricity sales (Joskow 1998:13). At the distribution level, municipal, federal and customer-owned companies still exist, and despite little switching of customers amongst retailers overall, retail competition is available in almost half the states (Sotkiewicz 2007).

b) Chile

In 1982, in a more deliberate effort to restructure the electricity supply industry towards competition, Chile enacted a new institutional framework for a decentralised ESI with greater private participation. Generally recognised as the pioneer of electricity market reforms, the Chilean ESI managed transmission on an open access basis giving generators non-discriminatory entry to the national grid as power generation was subjected to competitive forces (Raineri 2006:77). By 1996 there were eleven privately owned generation companies, and, by 2000, twenty-six private generators supplied all the country's power. Wholesale competition was implemented at the generation (and distribution) levels as new investor

⁵ The descriptions of early reformers are not intended to be exhaustive, but rather to briefly illuminate the origins of power sector reform. More extensive reviews of these earlier reformers are cited in the text.

financed projects were left to market forces and facilitated through legal and institutional changes (CEE 2002; Besant-Jones 2004:6). While the initial market structure and regulatory arrangements have not been without problems, the Chilean experience is largely hailed as a developing country success story and has been used to persuasively argue for private ownership and operation in the power sector (Fischer and Galetovic 2000; Pollitt 2005).

c) England and Wales

The British experience with power sector reform has been among the most widely referenced reform cases to date for industrial and developing countries alike. Since nationalisation in 1947, and until 1989, the ESI was under the control of the Central Electricity Generation Board (CEGB), which was responsible for generation and transmission (Newberry 2006:110). Although reform was driven mainly by an ideological pledge to reduce the role of the state, another key reason for change was the relatively high electricity prices. These had come about largely due to obligations by the CEGB to buy uneconomic British coal from suppliers, who enjoyed strong political influence from coalitions backed mainly by coal unions (Sioshansi and Pfaffenberger 2006:37). With the passage of the Electricity Act of 1989 the way was paved for privatisation in the electricity industry (UK Ministry of Justice 1989). Generation was vertically and horizontally separated and privatised⁶, and regulation was applied to promote competition at the generation level through a market mechanism, resulting in lower retail prices and private investment in generation (Bacon 1995).

d) Nordic Countries

Starting in Norway in 1990, new legislation through the Energy Act provided a legal framework for the restructuring and regulation of the power sector, and ultimately the establishment of the joint Nordic Electricity Exchange, also known as Nord Pool (Hjalmarsson 2000:3). The exchange officially began operating in 1993, gradually spreading to Sweden (1996), Finland (1997) and Denmark (2002), with much of generation remaining in public ownership. By 2003, when the utilities in these countries took up roughly three-quarters of generation through bilateral contracts, about a quarter of electricity produced was traded on the spot market managed by Nord Pool. This coincided with a period (2002-2003) of reduced generation when reservoir volumes were roughly half that of the preceding twenty years and spot prices reached two to three times the norm. Despite these supply side shocks,

⁶ Only nuclear power, which amounted to roughly 15 per cent of capacity at the time, was left in public ownership. The modern nuclear stations were eventually floated as British Energy in 1996 (Newberry 2006:114).

the system has operated reasonably well, and most analysts have reached the conclusion that the market institution handled the large supply variations in hydropower sufficiently (Fehr, Amundsen et al. 2004; Bergman 2005; Newbery 2005:12; Amundsen, Bergman et al. 2006:149).

It is worth mentioning that although restructuring among the early reformers, as described above, namely, USA, Chile, United Kingdom and some of the Nordic countries, came about through different paths, and despite their teething problems⁷ they all generally resulted in improved efficiencies in the industry by reducing state involvement (except for regulation) and by introducing competition.

2.1.2 The Reform Process

In most developing countries and some industrialised countries, the motivation for power sector reform originated from dissatisfaction with the performance of public utilities, increasing fiscal pressure on the state, the need to remove subsidies, and the difficulty in attracting finance for new investment (World Bank 1993:43; Bacon and Besant-Jones 2002:1). Reforms in the sector aimed to address these problems in a sustainable way, and optimise benefits to most stakeholders in the long-term.

Reforms were expected to follow a process that would enable the sector to move from a vertically integrated monopoly to a structure where generators were self-sufficient and operated at improved efficiencies, thereby achieving the promise of lower electricity prices.

⁷The California power crisis in 2001 demonstrated that regulatory rules which placed retail caps on distributors and precluding them from entering into forward contracts (moving bulk power trades into spot markets), as well as flaws in the market design encouraged market gaming or the exercise of market power by traders, utilities, generators and even the state itself. This drove one utility into bankruptcy and another near bankruptcy (Sweeney 2006:319). In the case of Chile, a severe drought from late 1997 well into 1999 sent shocks into the market and hobbled the country's electricity sector where hydropower comprised half of installed generation capacity. Fischer and Galtovic (2000) show that it was possible to manage the system without power outages, however, rigidity of the pricing system resulted in the system being unable to respond to the large supply-side shocks. The authors attribute the weakness to poor regulatory incentives and deficient regulatory governance. In the England and Wales pool, shortly after the introduction of competition, generators soon learnt that they could manipulate prices and set bids for their stations well above cost, forcing the regulator to institute a mechanism to cap pool prices (Bacon 1995).

An approach was loosely spelled out in the World Bank's 1993 policy paper for effective institutional regulatory and financial reform. It included the following key changes (World Bank 1993:43-52):

1. *Regulatory change*: to reduce government's involvement in the day-to-day operation of the sector, thereby increasing the autonomy and the accountability of staff responsible for managing the utility.
2. *Organisational change*: to facilitate the structural change from a vertically integrated monopoly into separate generation, transmission, distribution and marketing functions. This also entailed the establishment of centres to monitor the effectiveness of the performance of these functions with respect to management effectiveness, operational, financial and technical performance, and service quality.
3. *Commercialisation and corporatisation*: to orient the utility's business to operate more like a private company and less like the extension of a government department. This would entail enacting legislation allowing the utility to compete with other private companies on equal terms.
4. *Increased private sector participation*: to invite private investment in electricity through a number of ways, including: sale of assets and non-utility generation; franchising; contracting and leasing; and stock exchange listings.

Numerous authors have put forward variations of the fundamentals of reform that broadly resemble the above elements (Karekezi and Mutiso 1998; Kessides 2004:7-8; Victor and Heller 2006). Others have gone farther to include the number and sequence of the reform elements that will have a higher likelihood of leading to desired outcomes (Bacon and Besant-Jones 2002; Eberhard 2003; Jamasb, Newbery et al. 2005; Besant-Jones 2006:111-114).⁸ Over the years the steps, as noted generally above, came to be known as the 'standard

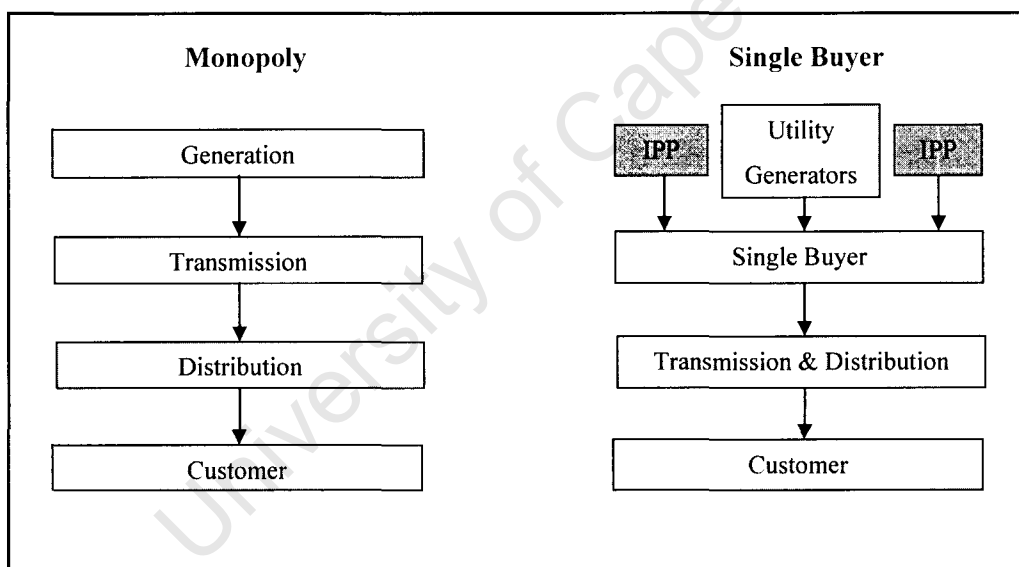
⁸ The rationale behind optimum sequencing of reform elements stems from the practicality in enacting reforms, e.g. passing legislation before regulation. It is important to emphasise the value of not committing to changes too early by keeping options open and delaying 'irreversible' changes until their potential benefits outweigh their potential cost, e.g. having effective regulation in place before divestiture and competition. In such a case, although government ownership may be unattractive for

prescription' for power sector reform (Hunt 2002:3-9). In following the 'standard prescription' of changing the industry structure from a monopoly to a fully fledged competitive sector, intermediate industry models have been adopted to facilitate the evolution (Hunt 2002:41-54; Gratwick and Eberhard 2008).

2.1.3 Models of Industry Reform

Market structure changes have been at the heart of power sector reform, and since competition requires a market, the first step to transforming the market structure from a monopoly is the single buyer model, an intermediate step in moving towards wholesale competition, as illustrated in Figure 2.1.

Figure 2. 1: Evolution of Monopoly to Single Buyer



Sources: Klein (1996:5), Hunt (2002:42-43), Barry and Roets (2004).

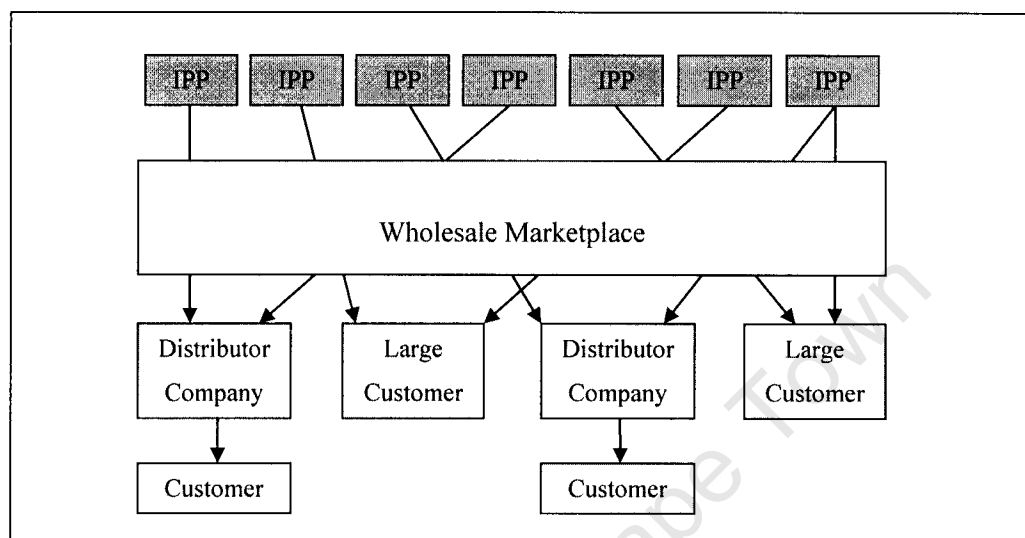
Arrows indicate the direction of energy flow. Payment flows would be reversed.

Under the single buyer arrangement only the existing integrated monopoly is allowed to purchase power from public and private generators, with purchases from private generators usually taking place through long-term contracts. Key advantages of the single buyer model in developing countries have been its ability to attract capital through long term contracts, its ability to centralise purchases, and its ease of implementation, since there are no fundamental

various reasons, optimal sequencing of reforms still guards the option of a well-formulated future privatisation.

changes to the market structure required to enable non-utility generators to participate in generation (Arizu, Gencer et al. 2006:7). Once there are sufficient numbers of buyers and sellers in the system, the model is extended to full competition as illustrated in Figure 2.2.

Figure 2. 2: Generation Wholesale Competition



Sources: Hunt (2002:45), Barry and Roets (2004).

Arrows indicate the direction of energy flow. Payment flows would be reversed.

A further development of Figure 2.2 would be competition in the distribution sector where commercial and residential customers would be enabled to choose their electricity supplier. The reform process as described in Section 2.1.2 would be carefully synchronised with movement between the models from a monopoly to wholesale competition.⁹

2.1.4 Shaping Reforms: Domestic Actors, the World Bank and Policy

Consultants

The standard prescription, as it came to be viewed, was adopted by numerous stakeholders. Although the model found domestic champions within developing countries, development finance institutions (DFI) and a large network of consultants should also be credited with formalising and spreading the reform agenda.

With many developing countries dependent on finance from the World Bank and other development finance institutions, they were in many respects obliged to follow the policies as

⁹ For a more detailed description on industry structure models adopted in the reform process, see Hunt and Shuttleworth (1996) and Hunt (2002).

prescribed by these institutions.¹⁰ Commitment lending policies, aimed at improving power sector reform outcomes, from multilateral and bilateral lending institutions therefore played a significant role in influencing reforms in developing countries (World Bank 1993:19-22; World Bank 2008b:14,21-30).

In addition, the World Bank supported funding for technical assistance missions, as well as initiatives to address the shortage of expertise for restructuring and regulation (World Bank 1993:17). A number of consultants who were involved in, for instance, the restructuring of the Chilean and British power sectors acted as advisors to development finance institutions as well as governments of developing countries, often being directly drawn in to the design of reforms (Gratwick and Eberhard 2008:8,22).

2.1.5 Reforms in Developing Countries

Reform models and lessons learned from the early reformers were thus transferred to developing countries as they set out on various paths to transform their respective power sectors in search of improved performances. Chile, with a relatively small system, was an early case in point, serving as a model for electricity privatisation and competition in industrialised and developing countries with smaller grids. As positive outcomes of reform were realised in countries that adopted reform exercises, momentum was gained, and a wave of reforms were initiated. To date, the developing region that has reformed the most is Latin America with Eastern Europe following closely.¹¹ South and East Asia and the Middle East and Africa regions have seen significantly less reform.¹²

A key reason for the large variation in the extent of reforms amongst developing regions is the diversity in the country and power sector contexts where reforms were instituted. The array of

¹⁰ By the late 1980s, 37 out of 50 Sub-Saharan African countries would implement World Bank imposed structural adjustment programmes (Gros and Prokopovych 2005:26).

¹¹ For more extensive appraisals of reforms in Latin America, see Estache and Rodriguez-Pardina (1998), Fischer and Serra (2000), Rudnick and Montero (2002), Pollit (2004), and Dyner, Arango and Larson (2006). For reviews on reforms in Eastern Europe, see Hirschhausen and Opitz (2000), Krishnaswamy and Stuggins (2003), and Lampietti (2004).

¹² For assessments on power sector reforms in South and East Asia, see Newbery (2006) and Onuki (2001).

starting conditions for many developing countries as well the range of endowments of developing countries made textbook approaches to reforming power sectors impossible for the most part, and reformers found it difficult to institute and sustain reforms in certain country contexts. Besant-Jones (2004:2-3) contrasts two generally held paradoxical views with respect to power sector reform in developing countries. The one is that reform should be beneficial to these countries since the starting conditions are generally poor and thus even a small change should have sizable positive effects on the sector due to the small base from which reforms are started. The other is that reforms are too complex an undertaking to successfully implement in smaller systems where the institutional capacity is already lacking and the sector cannot support measures to institute reforms and sustain them.

Although the contradiction elucidated by Besant-Jones is mainly with respect to small developing countries with small power systems, larger developing countries have also had their share of difficulties in enacting and sustaining reforms. Heller and Victor (2004:24), in a survey of five developing nations that have the largest economies and power sectors in their respective regions (Brazil, China, India, Mexico and South Africa), concluded that the difficulty of enacting reforms stems from the nature of state systems. They suggest that key political, legal, and institutional factors determine outcomes of the reform process (Heller and Victor 2004:4) and may explain why many countries do not make it all the way through the entire reform process. Arguing that efficiency improvements alone are not likely to be an adequate motivator for reform, they advocate that attributes such as financing, social functions performed by state utilities, and their systems of governance and control, ultimately guide the reform process as reforms become intertwined with reforms in other aspects of the economy. It is these reforms in other aspects of the economic, political or social systems which in many cases crowd out initial reform drivers in the power sector and result in insufficient momentum to sustain power sector reforms.

Nowhere is this phenomenon of strong links to other pressing reforms in other areas of the economy more evident than in the least developed countries, most of which are found in Africa and South East Asia. In these regions, restructuring has not progressed in the ways foreseen by theorists, and in most instances it has stagnated because the theory of power sector restructuring has not adequately mirrored the political and institutional realities associated with dismantling state-dominated systems and revolutionising them into market-oriented entities, as mentioned in section 1.2 (Heller, Tjong et al. 2003:1).

2.1.6 Reforms in Africa and the Emergence of Hybrid Markets

By any measure, power sector reform as per the ‘standard model’ has been difficult to implement in the African context. Bacon and Besant-Jones (2002:8) contrasted the reform progress of Africa and found the extent by which the region lags other developing regions to be significant, as illustrated in Table 2.1.

Table 2. 1: Number of Countries Having Taken Key Reform Steps by 1998

Key Reform Step	Sub-Saharan Africa (48)	East Asia and Pacific (9)	Europe and Central Asia (27)	Latin America and Caribbean (18)	Middle East and North Africa (8)	South Asia (5)
Corporatisation	15 (31%)	4 (44%)	17 (63%)	11 (61%)	2 (25%)	2 (40%)
Legislation Enacted	7 (15%)	3 (33%)	11 (41%)	14 (78%)	1 (13%)	2 (40%)
Institution of Regulator	4 (8%)	1 (11%)	12 (41%)	15 (83%)	0 (0%)	2 (40%)
Introduction of IPPs	9 (19%)	7 (78%)	9 (33%)	15 (83%)	1 (13%)	5 (100%)
Restructuring / Unbundling	4 (8%)	4 (44%)	14 (52%)	13 (72%)	3 (38%)	2 (40%)
Privatisation of Generation	2 (4%)	2 (22%)	10 (37%)	7 (39%)	1 (13%)	2 (40%)
Privatisation of Distribution	2 (4%)	1 (11%)	8 (30%)	8 (44%)	1 (13%)	1 (20%)
Reform Indicator	0.88 (15%)	2.44 (41%)	2.70 (45%)	4.28 (71%)	1.00 (17%)	3.00 (45%)

Source: Bacon and Besant-Jones (2002:8). The number of countries is presented in parentheses under each region in the headings.

There has been little unbundling of electricity supply industry functions to enable competition in African power sectors with the large majority of state-owned utilities remaining vertically integrated. There is no competition in the market, and, in many cases, little to no competition for the market. Even where there have been invitations to private participation, responses and outcomes have been poor (Gökgür and Jones 2006).

Few African countries have established independent regulatory agencies to help attract new investment by way of encouraging efficient and reliable service provision while attaining financial viability (Eberhard 2007). Moreover, even where there have been regulatory agencies established, in some cases their performance has been questionable, with the independence of regulators often undermined as governments exert pressure on regulators and tariff setting becomes politicised (Stern and Cubbin 2005:3-4). Effective regulation is also impeded by limited human resources as well as inadequate funding (Eberhard 2006).

A number of authors have challenged the practicality and applicability of enacting power sector reforms up to and including wholesale competition in African and other developing countries where conditions are significantly different to those countries where successes have been achieved and power sectors have reformed to the 'standard model' (Bayliss and Hall 2000; Pineau 2002; Wamukonya 2003; Williams and Ghanadan 2005; Douglas 2006; Yi-chong 2006). They have grounds for their criticism since nowhere in Africa has the standard model been achieved despite nearly two decades of reforms. This non-achievement is noteworthy, considering that a developing country like Argentina, for example, was able to reform its electricity sector to the point of wholesale competition in generation in less than three years (Pollitt 2004:5), and that was done without the abundance of theory and experience in power sector reform that has been gained more recently.

2.1.7 Problems Attracting Investment in Africa

Regardless of the theory and experience accumulated on power sector reform to date and the approaches proposed for various country contexts, the initial drivers for reform in Africa are still present. Technically and financially, state-owned utilities are still underperforming; service delivery with respect to quality of supply and electricity access is poor; and investment in new generation remains a key challenge.

In terms of attracting foreign investment into the power sector, a key reason for reforms in Africa, the continent attracted only about 5 per cent of global electricity investment into the sector by 1998 (World Bank 2008a), with less than 2 per cent going to Sub-Saharan Africa (Bacon and Besant-Jones 2002:11). This contrasts poorly to the Latin America and Caribbean region that attracted 40 per cent of investment, and the East Asia and Pacific region that attracted 36 per cent of investment.

Not only has Africa attracted less investment in generation infrastructure than other developing regions, investment is also on the decline. From a peak in 1997 of almost US\$1.8 billion into greenfield power generation projects, investment gradually diminished in 2006 to almost 25 per cent of that sum (World Bank 2008a). The downward trend in investment may be attributed to a number of reasons. Private sector investors were negatively affected by the financial shocks of the Asian and Latin American currency crises that spilled over into most of the developing world. Many contracts were renegotiated in these regions, and some were cancelled outright leaving investors with less appetite for foreign power markets. The contracts that were not cancelled left many host governments, including those in Africa where

currencies devalued significantly, with increased power charges due to the currency devaluations and inflexible purchasing contracts. Subsequently some governments, as in a case of Egypt, reverted to state funding of electricity infrastructure projects, bolstered by development finance institutions, which began to rethink their policies on conditional lending (Gratwick 2007:13). The demise of Enron globally also influenced private investors in foreign power markets to reduce their risk exposure in these emerging markets and return to their domicile markets, even though Enron's bankruptcy was triggered by events mostly unrelated to its developing country investments (Harris 2003:10).

2.1.8 Hybrid Markets: Solutions Giving Rise to New Challenges

Countries that have not been adversely affected by economic shocks have not necessarily seen more reform than those that have. Developing countries with IPPs that have not experienced significant currency shocks are still faced with the challenging task of integrating IPPs with rigid contractual arrangements into planned wholesale markets. The transitional step to guide the industry structure towards competition, i.e. the single buyer, has proved to be a tricky one to move beyond, as the issues of excess capacity, stranded costs and uneconomical tariffs prove to be a difficult challenges for market designers and policy makers (Woolf and Halpern 2001; Gambhir 2006). Lovei (2000) suggests that it may even be better to skip the single buyer step and adopt a market model with multiple buyers immediately after unbundling due the complexity of moving away from a single buyer arrangement. Despite the intricacies of single buyer arrangements, in certain cases the single buyer is considered the only alternative to distressed power systems. Within this arrangement there are a few mechanisms that mitigate against its many drawbacks such as increasing the lack of transparency, finding ways to accommodate the otherwise rigid contractual and institutional arrangements, and the reduction of contingent liabilities for host governments (Arizu, Gencer et al. 2006:4,9).

To their credit, in many countries, single buyer arrangements and IPPs have launched and sustained the reform process by demonstrating the benefits of private investment and management. Relatively easy to implement in power sectors that have not seen much reform, IPPs can enter wholesale power markets under any of the industry markets described in Section 2.1.3. They have generally sold their power under long-term power purchase agreements to state owned utilities acting as the single buyer, thereby affording private investors some mitigation against market risk. With reforms having stagnated and levelled out as hybrid markets, it would appear that the single buyer arrangement will dominate the African power sector landscape in the foreseeable future as the need for IPPs continues due to

insufficient state funding, and as political, economic and social challenges in many cases continue to stifle further reforms, as is evidenced in the empirical cases investigated in this thesis.

The literature now turns to state-owned enterprises in the ESI and the degree to which reforms have been successful in bringing about the changes envisioned with the objective of attracting investment and ensuring adequate generation capacity and making the sector more sustainable.

2.2 State-Owned Enterprises

State-owned enterprises (SOEs) have remained dominant in nearly all African countries and continue to be the providers of most of the electricity generated in Africa. The rationale for SOE existence, how they came into being, and how they function is connected to the problem of insufficient generation capacity. In many ways, SOEs have played a part in frustrating investment in the sector, both due to their own limited financial position and, more recently, by discouraging entry of private generators. This section briefly describes the rationale for SOEs and the reasons behind their poor performance. It gives an account of the two rounds of reforms which were intended to address the problems of poor SOE performance, the first between the 1960s and the 1980s, and the second from the 1980s onwards. Also included is a discussion of why efforts to address the poor performance of SOEs have been largely unsuccessful and the implications for continued investment in the sector. While SOE reforms have had a long history dating as far back to the immediate post-independence era of many African states, it sets the context for today's public utilities. In the empirical cases which follow from Chapter 3 through Chapter 6, it will be demonstrated how the manner in which SOEs have been managed and supported by governments has strong links to how investment in generation (private or public) has been sustained or stifled.

2.2.1 The Rise of State-Owned Enterprises: The Rationale for Public Champions

In the early 1960s, when many African countries gained their independence, a belief existed that government involvement in the economy would be crucial for development. This notion was, in part, due to the experience with previous colonial regimes (in which central economic planning often was the standard) and also to the successes achieved through centralised

economic planning in many western states (Appiah-Kubi 2001:199; Nellis 2005:4).¹³ Many development finance institutions also channelled their aid and loans to governments through state-owned enterprises that formed part of the socio-economic development organs of poorer nations, thereby providing funds for the expansion and, at times, creation of SOEs (Haile-Mariam and Mengistu 1988:1569).¹⁴ The practice of public ownership and management of utilities, established as a result of governments' development strategies, was almost universal in African countries. Apart from international views backing public control of infrastructure industries, the small size of economies and the lack of private capital markets made state owned enterprise a logical policy choice for most African states (Root 2001:565).

Even if domestic private capital existed, the notion among developing countries was that they could not rely on a *laissez-faire* approach toward industrialisation, especially in strategic sectors of the economy (Cooper 2001:11). Instead, late developers needed the state to have strong levers of control over the economy (including via import substitution strategies) to overcome the technological gap separating them from early developers. This development strategy was also a key reason for many of the nationalisations that occurred after independence in African states.

While the maximisation of profits was generally regarded as the primary objective of private corporations, particularly from a shareholder perspective, profitability was only one of many goals of SOEs, and evidence would suggest that it was not the most important one. In developing countries, SOEs were expected to create employment, keep prices down artificially, help develop laggard regions, and be at the vanguard of social progress, even if

¹³ Western economies in Europe and North America had adopted centralised state planning and control in many strategic sectors of their economies, especially after the Wall Street Crash in 1929 and the Great Depression of the 1930s (Toninelli 2000:10). In the period between the two world wars, the national enterprise model dominated (Vernon and Barnett 1974:104). The ideology continued to gain popularity even after World War II through the works of John Maynard Keynes, as government involvement became an integral part of reviving economies after the war.

¹⁴ It should also be noted that significant state involvement had its legitimacy in development economics at the time, which encouraged strong government engagement in the absence of local capitalists and any large inflow of foreign investment, or where foreign domination was prevalent (Appiah-Kubi 2001:201). The position amongst many African countries was that the gains in self-confidence and national pride would outweigh economic growth and 'supposed' technological advantages gained from association with industrialised nations through foreign ownership (Akinsanya 1981:775).

these goals hurt their financial and operational performance (Mazzolini 1979:713; Vernon 1979:9). The state was considered to be better placed to ensure allocative and distributive efficiencies than markets as welfare economics played an important role in social and economic development and as these functions reflected the ideological preferences of state leaders to guard against social inequality and promote social stability. State corporations could also attract loans at a lower rate than their private counterparts, thereby reducing the cost of capital, and theoretically providing goods and services at lower prices.

During the 1950s and 1960s, as the demand for electric power increased dramatically, coordination procedures for system operations were consolidated and a national self-sufficiency theory prevailed, implying that electricity should be controlled as a strategic resource. Financing the electric power system became dominated by the state or state controlled banks (Heller and Victor 2004:3). As economies of scale in the power sector increased during this period, it reinforced the conventional political and developmental driving forces for state ownership and control, and suggested that electricity supply was indeed an integrated natural monopoly as first laid out in section 2.1 (Heller and Victor 2004:3).

2.2.2 Inefficiency, Poor Performance and Financial Distress

In the mid to late 1960s, many public enterprises started to register poor financial performance, which led to increasing government debt. Through state subventions to support loss-making entities, SOEs were drawing down the state's fiscal resources, instead of contributing to them as originally intended.¹⁵ This, in turn, translated into minimal investment in infrastructure expansion and general maintenance, negatively impacting on the quality of services provided to customers, and subsequently, discouraging private investment in other industry sectors.

The causes of poor performance were multifarious; however, the fundamental conclusion was that public enterprises were managed according to too many divergent objectives (Vernon 1979:10; Aharoni 1981:1341; Shirley 1983; Ramamurti 1987:877; Mascarenhas 1988:166). The combination of commercial and social objectives invariably led to political meddling in

¹⁵ As an example, the increasing foreign debt for the Zambia Industrial and Mining Corporation (ZIMCO) alone accounted for over half of the nation's total debt by the mid 1980s (Ayub and Hegstad 1987:86).

company operational decisions to the extent that commercial performance and organisational efficiency were severely compromised (Ayoub-Geday 2006).¹⁶

Political interference stemmed from arrangements whereby ministers often served as chairmen or held seats on SOE boards (Blunt 1970:33). This led to a push towards the political and social objectives of the respective ministry (an organ of the state) at the expense of the commercial and performance goals of SOEs. In addition, board members often lacked training in the specifics of the industry since their appointments were based more on their political associations rather than industrial competence (Shirley 1983; Ayub and Hegstad 1987:96).

Weak and sometimes absent performance evaluation monitoring meant that there were few indicators that would alert external controllers and SOE stakeholders of business areas displaying unsatisfactory performance (Ramamurti 1987). The lack of credible evaluation criteria often stemmed not only from the knowledge that profits were not the overriding objectives of SOEs, but also from the inability to translate clear social objectives into measurable performance criteria. Few governments were capable of providing SOEs with clear-cut performance goals and credible trade-offs amongst conflicting objectives (Zif 1981; Ramamurti 1987:877).¹⁷

SOE managers lacked the autonomy to change inefficient relations with business associates such as suppliers and service providers. These business relations were often with other public enterprises in search of partnerships that would increase the performance of their own undertakings. Executives also had difficulty in shedding labour where public corporations were clearly overstaffed and were sometimes obliged to add more workers than needed or

¹⁶ The vagueness in objectives may be considered a managerial problem since managers became unclear on what was really expected from them, and also an opportunity for managers since the multiple objectives provided a built-in excuse for not fulfilling a specific objective (Mascarenhas 1988:166). Eggleston (1931) argued that in such a system where an enterprise is managed directly by a state department and its officials are likely to be political rather than industrial experts, officials cannot have much initiative and thus cannot be held responsible for the success or failure of the enterprise.

¹⁷ Conventional accounting and reporting systems, which were developed and used in the private sector, were incompatible with SOE objectives, and where they were employed they often gave external controllers performance measures that were inappropriate and inconsistent with the overall goals of SOEs (Ramamurti 1987:891-892).

wanted to their payrolls (Vernon and Barnett 1974:107)¹⁸. The limited control that executives had over labour and other costs contributed to the resulting lack of profitability of their utilities.

To make matters worse, governments frequently failed to increase tariffs to the point where they were below levels of cost recovery.¹⁹ This, in turn, limited growth in terms of network expansions and related service improvements. Low collection rates further strained the financial situation of SOEs with government departments and other SOEs sometimes being the worst defaulters on bills. Even with the help of tax exempt status and despite most of their investment income coming from government budgets, many SOEs could not maintain positive cash flows (Haile-Mariam and Mengistu 1988:1572).

In the most perverse cases, it could be argued that SOEs became an apparatus for misappropriation of funds, corruption and nepotism, to further the interests of the ruling elites (Vernon and Barnett 1974:107; Haile-Mariam and Mengistu 1988:1570). This, in turn, led to SOEs becoming even more inefficient, as their control reflected less the interests of the corporation and more the parochial interests of a select few.²⁰

¹⁸ In 1987, for example, the numbers of electricity utility customers per employee reported were nine for Burundi, eight for Botswana and six for Rwanda. As a reference the USA and France had 240 and 222 customers per employee respectively (Escay 1990).

¹⁹ A report based on a survey for over sixty developing countries showed that electricity tariffs fell by roughly 35 per cent between 1983 and 1987 in constant US\$ terms and that developing countries generally faced tariff levels that were too low to encourage efficient use of electricity, and utilities were unable to raise sufficient revenues to finance their expansion needs. In 80 percent of developing countries tariffs were found to be below the long run marginal cost (LRMC) of production and two thirds of African countries surveyed did not plan to base their tariffs on the economic cost of power (World Bank 1990:3-15).

²⁰ In extreme cases, SOEs were created deliberately as a cover for political party fundraising. Blunt (1970:33) reports this to have been the case with the National Development Company in Ghana (which was investigated by the Azu Crabbe Commission), and the National Investment and Properties Company in Nigeria (which was investigated by the Coker Commission).

2.2.3 Reform: A Prescription for Poor Performance

2.2.3.1 Reaction by Development Finance Institutions

Development finance institutions that lent money to SOEs, most notably the World Bank, became concerned and gave much attention to the predicament by: examining the underlying causes of the problem in more detail; assisting governments to improve performance through instituting monitoring methods; and making further borrowing conditional on improved policy formulation and implementation, as well as institutional changes to improve governance functions for SOEs (Nellis 2005:10). The focus on the problems relating to SOEs corresponded to the period of the World Bank's structural adjustment lending programme in the late 1970s, where infrastructure sector performance featured prominently in the bank's objectives.²¹ African states were prominent amongst developing countries that accepted the terms of the loans from the Bretton Woods institutions due to their ailing SOEs, and hence attracted noteworthy technical assistance operations and training assignments, which would carry on well into the 1980s to improve SOE performance (Gros and Prokopovych 2005:26).

2.2.3.2 The First Round of Reforms: SOE Performance Improvements

Reforms proposed to address the poor performance of SOEs took the form of adopting a 'modern enterprise system' by transforming SOEs into shareholding corporations, all within an overall framework of public ownership. Corporatisation, in part, was intended to clarify the rights of SOEs and free them from ministerial and administrative interference by establishing them as separate legal entities run by professional managers (Anastassopoulos 1985). Furthermore, reforms focussed on operational analysis to determine the array of factors leading to SOE losses and a wide range of restructuring and performance improvement

²¹ Structural adjustment policy changes and conditions were instituted by the World Bank and the International Monetary Fund (IMF) to ensure that lending would be done in a manner that would meet the initial objectives of the loans. To correct for borrowing countries' fiscal imbalances, Structural Adjustment Programmes (SAPs) were instituted to reduce protectionist behaviour through the reduction of trade barriers and the promotion of free market principles (Welch and Oringer 1998). Critics of the World Bank's SAPs contend that the acceptance of SAPs was merely because of pressure exerted by the World Bank and IMF since developing countries had limited alternate access to funds, and complied due to a lack of options.

measures, which excluded ownership changes in infrastructure sectors such as electricity. Some of the specific reforms requested, as noted by Nellis (2005:12), included:

- Classification studies to clarify the role of the state and categorise SOE portfolios into companies that should be retained, restructured, sold or closed.
- Legal and administrative reforms aimed at making public enterprises more commercial in nature by rationalising control procedures, increasing the autonomy of SOE managers, and altering the form, duties and roles of boards of directors.
- Changes in determining pricing formulae for infrastructure service tariffs, including review periods and criteria for ad-hoc reviews.
- Labour studies and policies for determining the correct levels of staffing, the funding of retrenchment mechanisms, and training and redeployment schemes.
- Rationalising of financial systems to reduce automatic or concessionary access to credit.
- Creating or bolstering SOE monitoring bodies and strengthening the scrutiny of SOE expenditures and borrowing.
- Reviewing the competence and qualifications of managers in infrastructure SOEs and studying and improving management procedures.
- Performance contracts were used to provide a means to clarify performance objectives and to monitor and judge performance against prior agreed criteria.
- Privatisation or preparation for privatisation of non-strategic SOEs which were of a commercial nature.

2.2.3.3 Implementation and Reform Outcomes

Although many initiatives were called for to address the operational and fiscal troubles of state corporations, implementation proved challenging. In the case of Senegal, Nellis (2005:15) reports that: tariff hikes agreed on by government were later rejected; pledges from government agencies to pay their bills were not kept; commitments to make investment capital available to infrastructure SOEs were not honoured; and, contrary to agreements, managers were not allowed to fire workers, change suppliers or cut off service to non-paying customers. Where price increases were realised to recover the cost of commodities or services, the culture of non-payment persisted, and where they were paid, it often translated into inflationary pressures within the fiscal system, an unintended (and often not well thought through in terms of impact) consequence of the increases. Resistance and disillusionment also came from customers who found themselves paying more for no notable increase in service

quality (Nellis 2005:13). Often, the ill-coordinated cessation of subventions to loss-making SOEs strained working capital, leading governments to arrange extensions of loans with state-owned banks to ailing SOEs (Kikeri, Nellis et al. 1992:17). In these cases, the problems of poor fiscal discipline were shifted rather than resolved. Retrenchment of excess workers also proved to be easier said than done, with reductions in salaried costs being modest.²² Side-stepping by governments and frequent recanting on initial commitments to support SOE rehabilitation were common obstacles to restructuring efforts, since they were generally politically risky and socially upsetting.

In some cases, written performance contracts provided a means to clarify performance objectives and to monitor and judge performance against prior agreed criteria. In other cases, agency problems between governments and SOEs persisted in contributing to the poor performance of SOEs as information asymmetry caused problems of moral hazard and adverse selection.²³ As a result, it was difficult for the state to set and enforce equitable contracts that required a reasonable amount of effort on the part of managers for a commensurate reward. Shirley and Xu (1997) analysed the impact of twelve written performance contracts between SOE managers and their governments in six developing countries and found no evidence to support the argument that improved performance could be credited to contracts. In half of the cases, pre-contract productivity performance trends continued and in a quarter of the cases performance deteriorated after the contracts were in force. Problems encountered were that contract targets changed too frequently; there were too

²² In many cases, public enterprises have been subject to gross overstaffing in the past, and in general governments wanted to avoid the already high levels of unemployment that were prevalent in most African states. In addition, collective bargaining arrangements concluded between unions and SOEs granted employees generous retrenchment payouts. Given that some SOEs' liabilities exceeded their assets, the inability to pay termination provisions brought reform to a halt (Tangri 1991:532).

²³ Moral hazard is the notion that an entity largely insulated from risk will behave differently when exposed to the whole or a significantly larger stake of the risk. SOEs managers are normally exposed to less risk due to soft budgets and insufficient retrenchment disincentives. Information asymmetry occurs when one party to an agreement has more or better information than the other party. This impairs the balance of power in the agreement and could result in the agreement going awry. SOE managers often know more about the operational aspects of the business than government officials who they engage with during performance contracting and could be tempted to demand huge bonuses for relatively soft performance targets. Adverse selection is the tendency for a higher risk group to seek coverage more than less risky groups. In the case of SOEs, adverse selection occurs when the state decides on the future of loss-making corporations in the absence of complete information.

many objectives from too many principals; and governments pledged actions that they were not motivated, or politically able, to implement.²⁴ When managers put a high probability on government renegeing on its commitments such as providing support, increasing tariffs, or paying incentives, they invariably would not exert the effort to effect performance improvements. Such weak incentives therefore led to shirking by managers.²⁵

Despite some successes from the wave of reforms to address SOE performance, outcomes were largely ineffective in bringing sustained change. By 1990, development finance institutions concluded that a new approach to SOE performance improvement was required. Despite the reluctance of African governments to move towards privatisation in commercial and manufacturing sectors in the 1980s, development finance institutions pushed for private sector involvement to become the driving force of SOE reform in the 1990s (Nellis 2005:17).²⁶

2.2.3.4 The Second Round of Reforms: Privatisation

Just as the rationale for SOEs (in the preceding half century) had come from western states (see Section 2.2.1), the motivation for privatisation also came from industrialised countries. In the UK and the USA during the 1980s, in a departure from Keynesian economics, the Thatcher and Reagan administrations instituted liberal economic policies informed by the

²⁴ A reason for the pledges that government could not or would not fulfill was the lack of credible alternative options as the helpline from the World Bank was often the only one extended. In Ghana and Senegal, for example, promises were made to obtain foreign aid, which may not have been forthcoming without such concrete pledges (Shirley and Xu 1997).

²⁵ Shirley and Xu (1997:5) ascribe the problems in contracting between government and managers to contracting maturity (or immaturity) since government agencies were in the early phases of a learning process on how to contract successfully. They also note that commitment to honour the contracts when circumstances changed was a problem since it was difficult, if not impossible, to force the state to comply.

²⁶ Privatisation (involving a change in ownership) was prioritized for SOEs that exhibited an improvement in performance under the first round of reforms for the following reason. In times of crisis, governments committed to hard budgets, granted managers autonomy, and gave priority to commercial objectives. However, as the crisis disappeared, gradually government commitment also faded. Therefore, even in cases where previous reforms not involving ownership changes yielded positive results, privatisation was still thought to be beneficial since it would lock in the gains from earlier reform efforts (World Bank 1996:50).

works of Hayek and Friedman (Yergin and Stanislaw 1998)²⁷. These largely successful privatisations resulting in improved sector performances in industrial nations, as well as the transition economies of Latin America, helped make a case for privatisation in less endowed countries in Africa.

The change in western economic policies and the growing sense that previous performance improvement policies had failed, made some officials in developing country governments question earlier commitments to state-led development and sparked debate on the possibility for more far-reaching market reforms, including divestiture.²⁸ Towards the mid-1990s, a number of developing country governments thus focussed on divestiture, especially within infrastructure industries (sectors that had been spared in an earlier wave of reforms due to the fact that they were considered natural state-owned monopolies, unlike other commercially-oriented enterprises in manufacturing) (World World Bank 1995a:26). It is important to reiterate that the World Bank and other development finance institutions lent strong support to privatisation as a change of ownership in order to improve the performances of SOEs and meet the objectives of reforms (Haile-Mariam and Mengistu 1988:1565; Kikeri, Nellis et al. 1992:32).

It was expected that divestiture would address the question of ownership, which was believed to be at the root of the problem of poor SOE performance, and also bring in foreign exchange receipts that would alleviate pressure on the balance of payments (Appiah-Kubi 2001:212). In addition, privatisation in the form of divestiture held the potential to stimulate the economy and yield additional tax revenues by the entry of a rejuvenated private sector. Furthermore, it could promote open markets and reduce the power of trade unions.

By the mid-1990s the concept of improving SOE performance under government ownership was therefore exchanged for privatisation and private participation in infrastructure (PPI) amongst development finance institutions in transitional and developing economies (Nellis 2005:16-19). As will be seen in Chapter 4, in Africa, Cote d'Ivoire was the first country to

²⁷ In the USA much of the generation was already in private hands.

²⁸ Christensen (1998) observed that in the case of Ghana, the low political cost of government interference was one of the main reasons for the failed reforms, and that divestiture (partial or full disposal of public enterprises through a sale, closure or bankruptcy) was thought to be a more efficient way of dealing with poor SOE performance.

invite private participation in its ESI, first via a management contract to a private consortium to manage its state-owned utility in 1990 and then with an IPP four years later.

2.2.4 Reform Loses Flavour and SOEs Survive

Although divestitures in electricity generation infrastructure were few in Africa²⁹, by the second half of the 1990s, IPPs, where contracts were entered into with utilities and host governments to add capacity and supply power, were on the increase. Many African countries formulated reform plans to privatise and introduce competition at a generation and a distribution level, but efforts have in almost all cases stopped short thereof, as first detailed in Section 2.1.6. Publicly owned utilities have thus remained dominant in almost all African power sectors. Although in some cases SOE performance has improved, the utilities of most countries are still not able to finance capacity additions to support the increased demand. And, while the private sector has a role to play in additional investment, the poor financial state of public utilities has hindered investment.

Although privatisation of SOEs became a common occurrence in commercial and manufacturing sectors, infrastructure sectors -- particularly the electricity supply industry-- have been among the most difficult to reform. Changes in ownership have been difficult to implement for a number of reasons, as detailed below, and are reminiscent of earlier attempts starting in the 1960s (as discussed in Section 2.2.2).

a) Comparing Ownership Performance

While privatisation was largely associated with increased performance objectives, there was evidence to suggest that, in certain contexts, there was little difference between the performance of private and state owned companies, putting the factor of ownership as the single determinant into question.³⁰ Instances where divestitures hardly showed an improvement by private capital (compared to state ownership) merely increased the mounting

²⁹ According to the World Bank PPI Database, between 1990 and 2007 only one full divestiture in electricity was realised (Zambia) and four partial divestitures (Cape Verde, Kenya, Zambia and Zimbabwe) (World Bank 2008a).

³⁰ For examples see Dollar (1990), Bosc, Koh, Berg and Kenny (1996), Breton and Côté (2002), Omran (2003), Feng, Sun and Tong (2004).

resistance to privatisation.³¹ This, in turn, slowed the momentum of privatisation as intellectuals, government officials, non-governmental organisations, academics and other interest groups started to challenge the appropriateness of divestiture as a means to performance improvement.³² Even in instances where private participation did not involve a change in ownership (e.g. through management contracts), performance was questioned by stakeholders, whose expectations were not realised by the contract outcomes, as was the experience in Tanzania.³³

³¹ For example in 2003, US-based AES bought a 50 per cent stake in Kelvin power station, a coal-fired plant supplying roughly a quarter of Johannesburg's electricity in South Africa. Following the Enron scandal, AES reassessed its international operations and decided to pull out of its South African operations. The shareholding was then sold to a consortium led by CDC Globeleq, but by 2006 CDC Globeleq abandoned its stake in Kelvin, citing technical problems at the plant, after it recorded losses of £15.6m on the plant. After spending approximately £30m on refurbishing the plant, the plant could only generate 25 per cent of its rated 600MW capacity (Hall 2007:11-12).

³² It has to be stated here that any comparison between state and private corporations needs to be made with caution. Public companies are often required to fulfil some societal objectives which their private counterparts are not necessarily obliged to fulfil. Governments may have acquired loss-making companies for non-economic or strategic reasons, thereby nullifying comparison on a profit basis. Therefore, even when the financial performance of private firms has been found to be superior, it does not necessarily mean that they were more productive. Furthermore, comparison becomes problematic when the review or comparison period is too static. This could be the case when a new and inexperienced public enterprise is compared with a well-established private company. Finally, while large profits may indicate efficiency, they may reflect market distortions and monopolistic pricing. For example, Ghana's profitable distilleries and cocoa factories owed their financial success almost completely to monopolistic positions and protection from foreign competition, while their value added at international prices was negative (Ayub and Hegstad 1987:82).

³³ In the management contract involving the Tanzania Electricity Supply Company Limited (TANESCO) and NetGroup Solutions that was aimed at preparing the national utility for privatisation, it was found that the management contract outcome was highly dependent on how governance and performance incentives were structured. Revenue incentives made up more than 99 per cent of contract fees that were awarded, and the contract failed to place sufficient emphasis on customer service, as it was assumed that it would automatically follow from other objectives. With customer service standards and incentives largely omitted from the contract scope, it was hardly surprising that end-users were disappointed by the customer service outcomes of the management contract despite the contractor improving collection rates and nearly doubling utility revenues in two years (Ghanadan and Eberhard 2007).

b) Negative Perceptions about Privatisation

Speculation about the lack of transparency, including allegations of corruption in the management of divestiture, has also negatively impacted the overall impression of privatization. First, many of the transactions were never publicised, contributing to this impression (Appiah-Kubi 2001:223). Furthermore, in many cases, absent or weak regulatory frameworks after divestiture allowed privatised business to continue protecting their monopolistic positions rather than increase their competitiveness. In addition, many African states lacked the resources and skills to negotiate with multinational or domestic private firms in such a way to ensure that the public interest was protected during the sale, or to institute and sustain credible regulatory institutions after the sale (Nellis 2005:28). Persistent claims that assets were sold at artificially low prices also added to negative perceptions of privatisation as uncertainties clouded valuation methodologies, as did buyers who delayed payments.

Even where there was no transfer of ownership, rumours and accusations of embezzlement by foreigners fuelled negative perceptions relating to the practice of private participation as happened in the case of Cameroon.³⁴ Although such instances were not the norm, their occurrences did slow momentum to privatisation as they were widely cited by opponents to privatisation.

c) Weak Regulatory and Tariff Reform

Non cost-reflective tariff structures have been key obstacles in attracting private sector investment. This was observed in Zimbabwe, where in 1991, as part of wider SOE reforms, the Government of Zimbabwe embarked on reforms to improve the performance of the national utility, the Zimbabwe Electricity Supply Authority (ZESA). While there have been improvements in the technical operations and customer service areas, little reform progress

³⁴ In 2000, a bid was launched to sell off 51 per cent of the Cameroon electricity utility, Société Nationale d'Electricité de Cameroun, SONEL, for which the government of Cameroon was expecting a purchase price of US\$80-90m. AES was the only company among five pre-qualifying consortia that submitted a bid and subsequently bought the majority stake in Sonel for US\$70m. In March 2002, AES' parent company was reported to be in financial difficulty, and AES was accused of diverting funds from SONEL to its parent company (UNECA 2002:8). Despite an improvement in the relationship and a turnaround in the performance of the utility, the period shortly after AES took over the management of SONEL negatively impacted on perceptions of privatisation due to the accusations, making it difficult for government and investors to rally support from the masses for further private sector participation.

has occurred on the legal and regulatory fronts. Failure to raise tariffs affected the utility's financial performance and has frustrated the government's efforts to attract private sector investment. Furthermore, the failure to increase tariffs to the long run marginal cost (LRMC) may be directly linked to the failed negotiations of the Hwange Privatisation and Expansion Project³⁵ and the Gokwe North Project³⁶ (Mangwengwende 2002). Zimbabwe is only one example of many that illustrates how tariffs that are insufficient to cover the economic cost of production hamper efforts at transforming SOEs and increasing investment. Later, in the cases of Ghana and Morocco it will be shown further how weak regulatory reform and uneconomic tariffs continue to cast a shadow on financing prospects for continued generation investment.

d) High Perceived Risk and Lack of Private Sector Interest

Many countries have not been able to attract quality private investors due to the perception of high country and sector risks (Bacon and Besant-Jones 2002:5). In 2001, the World Bank financed the bidding process for 51 per cent of the shares of Mauritania's national utility, SOMELEC, after making privatisation a condition for debt reduction. After two pre-qualifiers for the bid withdrew, only Morocco's Office Nationale d'Electricité (ONE) was left in the running. ONE subsequently put in a low bid in the hope that the Government of Mauritania would feel compelled to acquiesce. Realising that the country would be incurring a significant loss in accepting the offer from ONE, the government renegotiated its debt reduction

³⁵ In September 1996, the Government of Zimbabwe issued a letter of intent for the sale and expansion of Hwange power station. The joint venture between YTL Corporation of Malaysia (51 per cent) and Zesa (49 per cent) was expected to finance the expansion of 2 X 300 MW units to the value of US\$550m on a non-recourse basis. The value of the existing plant as stated by the government was US\$627m. In order for the investment to attract a 20 per cent return as asked from the investor, tariffs needed to be increased from 2.97US c/kWh in 1996 to 6.2 US c/kWh by 2000. When the proposed tariff increase was considered to be too high by government, YTL proposed to pay US\$184m for the existing plant. Having already publicly put US\$627m as the fair value of the plant, the government could not accept the large discount on the plant and called off the negotiations, without reaching an agreement.

³⁶ In April 1997, the Government of Zimbabwe signed a letter of intent with National Power and Rio Tinto of the UK to develop a 1400MW plant at Gokwe North. Inclusive of finance charges, the coal-fired development would cost US\$1600m. Project viability was conditional on achieving tariffs reflective of the LRMC by the year of commissioning of the first unit. With the government unable to fulfill the commitment, the project failed to attract the financial support and negotiations were abandoned in early 2000.

conditions with the World Bank, which, in turn, agreed that Mauritania could not be held liable for the failed privatisation (AEI 2002).

Mauritania is not the only country in the West African region to have difficulty in attracting credible private investors. In 1996, the Senegalese government embarked on reforms, with the support of the World Bank and other donors, which were aimed at eventually privatising the national electricity utility (Fall 2004). Eager to transform its ailing electricity industry it initiated institutional, legal and regulatory changes and by March 1999 it had sold off 34 per cent of the Senegal Electric Company (SENELEC). The partial privatisation of the utility lasted only 18 months mainly due to conflicts over investment and pricing issues. A new government bought back the shares from Hydro-Quebec International and Elyo, the company which initially secured the bid and, in 2001, tried to re-privatise the utility with a new framework to address the shortcomings that strained the first relationship. Only two consortia responded and, despite active discussions, successful negotiations did not lead to any deal closures. Ultimately, the privatisation effort was abandoned, with the private partners losing financially and the Senegalese government still saddled with the burden of subsidising the utility (Gökgür and Jones 2006).

e) Economic Nationalism and High Political Costs

The lack of private sector interest also has roots in economic nationalism. Many host countries must share the responsibility for the lack of investment appeal to the private sector due to its hostility towards PPI initiatives. This antagonism may partly be explained by the idea that privatisation was 'forced' onto countries with hardly any credible alternative options since Africa, in general, was a policy taker, not a policy maker. *"In very few cases was the decision to privatise totally home-grown or strongly endorsed or supported by domestic decision- and opinion- makers. While African proponents of privatisation could be found, the main impetus for divestiture came from the donor community in general, and the [development] finance institutions in particular"* (Nellis 2005:16).

A key problem in infrastructure is the perception of loss of sovereignty. When infrastructure in strategic sectors is placed into the hands of foreigners, it conjures up fears of neo-colonialism. There is a strong link between the antagonism to the privatisations of the 1980s and the nationalisations that preceded reforms in the 1960s. *"There is a pattern throughout the continent: Africans want control in their own house"* (Akinsanya 1981:776). Thus, the sale of publicly owned infrastructure assets was often especially sensitive politically and the

desire to appease economic nationalist opposition influenced the appetite for privatisation.³⁷ In Ghana, for example, to allay the fears of opposition parties, the government maintained minority shareholdings in divested companies and undertook fewer divestitures during election years (Appiah-Kubi 2001:222). Even in new companies, as will be seen in Chapter 3, despite the state having limited resources to partner in the country first IPP on an 50/50 equity basis between the government and the private sector as initially intended, it still pushed for a shareholding and only managed to raise cash which could give it claim to a 10 per cent of the projects equity.

Despite a sense of economic nationalism in Africa, where the popularity of officials (and ultimately political survival) was more dependent on enacting reforms to reverse the downward trend of SOE performance than on political patronage, there was generally a greater reform momentum than in countries where the political survival of governments depended on defending SOEs (Appiah-Kubi 2001:198). Nevertheless, in many cases, political considerations shaped the outcomes of the privatisation process, as the political costs of privatisation swayed governments into action or inaction.³⁸

There were thus many investor, sector, and country related challenges that aggregated and made divesting of monopoly SOE electricity utilities, the implementation of management contracts, and broader private sector participation, difficult in African power sectors. These challenges will be described in the case study chapters.

³⁷ Even where local capital was a possibility, privatisation was often viewed as being against the political interest of leaders in government since divestiture might undermine the government's ability to use public corporations as instruments of employment creation and patronage (Tangri 1991:526). In addition, governments were reluctant to shake up the management of SOEs unless they were sure that new managers could take over smoothly and swiftly (Vernon 1984:47). The fact that skills in utilities were in short supply (especially knowledge of the local industry) gave managers some bargaining power with governments.

³⁸ In Egypt for example, despite net foreign aid diminishing from 5 per cent of Gross Domestic Product (GDP) in 1980 to zero in 1988, and trending into negative in 1989, the SOE workforce was important enough in the leadership's support base to condone poor SOE performance (at least in the short term), and the aid crisis was not considered a strong enough imperative to lead to successful reforms (Shirley 1999:129).

2.2.5 Views Regarding Future Reforms

What is to be done and what should be the focus of the next round of reforms to bring about sustained improvements in African power sectors? Should countries revert to the non-divestiture reforms instituted from the 1960s to the 1980s given the problems encountered with privatisation, or should the last three decades of reform failures with state ownership be reason enough to do away with state ownership altogether and take away ‘the government of business from the business of government’?

In spite of the number of African countries that embarked on reforms, the fact that nowhere in Africa have governments been able to fully dismantle the public apparatus in the power sector suggests that there is still a need for SOEs in electricity – the question at the heart of the issue remains, as asked by Seidman (1954:183) more than half a century ago, is “*How can the operating and financial flexibility required for the successful conduct of a business enterprise be reconciled with the need for controls to assure public accountability and consistency in public policy?*”

While at this stage the road to future SOE reform efforts remains blurred in terms of how SOEs will be dealt with, a number of authors have presented varied views on what the next round of improvements should entail.

Shirley (1999) analysed the political economy of state enterprise reform and concluded that because privatisation has similar political costs as corporatisation (instituted in the first round of reforms from the 1960s to the 1980s), the two (privatisation and corporatisation) tend to succeed or fail together. She argues that where reform was politically feasible, desirable and credible, countries corporatised and privatised successfully, whereas where countries were not politically ready to reform, substitute ownership strategies were not successful in improving performance. Shirley’s comprehensive view of reforms is relevant here since earnest reforms are likely to retrench excess workers, reduce subsidies to suppliers and customers, and affect changes in management, regardless of the impact on government ownership (Shirley 1999:128-129). From Shirley’s analysis a corollary could be that any kind of reform should only be embarked on in countries that are ready politically, socially and, perhaps, economically for such transformation and where government commitment to reforms is compelling.

Nellis (2005:29) believes that the SOE model should not be jettisoned, given the difficulties in making PPI work effectively in Africa. He cautions, however, that the limitations of the PPI approach should be recognised, and that stakeholders should work harder at creating the conditions to make it function effectively. Gómez-Ibáñez (2007) shares this view and suggests that although earlier reform efforts produced only moderate successes, some of them, when carefully applied, may help in improving the performance of infrastructure SOEs. With the difficulties encountered with privatisation, it may be a reasonable prospect to give reform under government ownership another chance in selective cases. Nellis and Gómez-Ibáñez' support for giving SOEs a second chance stems from the idea that experience over the last three decades has taught governments, donors and other institutions valuable lessons, allowing them to proceed with caution. Due to the advances made in the theory of performance and management contracts, corporate governance, regulatory arrangements for SOEs in less endowed country contexts, centralised and decentralised ownership functions, the impact and functioning of institutions, the management of managerial incentives, three decades later we are armed with new and more current knowledge on how to tackle the old problems of poor SOE performance.

Irwin and Yamamoto (2004), although cautioning about the prospects of performance improvement in electricity SOEs without privatisation, maintain that improvements in corporate governance are still worth pursuing to create an arms length relationship between the government and the utility. What is needed are changes to the rules and the structures that govern the relationship between governments and SOEs, which should, in turn, impact on the long-term performance of the SOEs and the sector. Again, given the advances made in the theory and practice of corporate and SOE governance, there may be a way forward as hoped by Irwin and Yamamoto.³⁹ The view that SOE performances may be improved through better formulated governance arrangements is shared by Vagliasindi (2008). She advises that governance guidelines be tailored to the specific infrastructure sectors and reflect market structures and regulatory arrangements in which SOEs operate. Cautioning against partial remedies, she stresses that internal as well as external governance factors need to be

³⁹ Classic corporate governance has two important assumptions built into it. Firstly, the right of free exit of shareholders and the threat of a hostile take-over is relied on by an efficient equity market. Secondly, the maximisation of shareholders' wealth (as opposed to social benefits) is the principle criterion for efficiency (Kuznetsov 1999:443). These assumptions may contradict the realities for SOEs in most African states where private equity in SOEs is absent, and where social objectives feature heavily due to the gap in development.

holistically addressed since focussing only on one governance dimension is not likely to yield improved SOE performance in a sustainable way.

Heller and Victor (2004:24) conclude that the difficulty in reforming SOEs stems from the nature of state-centred systems. This includes their systems of governance and control, their financing, and the many ancillary societal functions that are performed by SOEs. They advocate that the unlocking of performance improvements of SOEs lies in better understanding how institutions discourage sector progress, and strengthening the institutions (formal or informal) that govern their existence and operations to achieve sustained progress. Institutions do matter (especially the institutional links between government and utilities) and they ultimately have a pervasive influence on the long-run character of economies (Williamson 2000:596). Good economic management, therefore, depends on the effective design and quality of public sector institutions that are responsible for executing reform policies and providing public service (Estache and Martimort 1999).

It is clear that governments alone will not be able to finance the expansion of electricity infrastructure to meet the objectives of development. The private sector will have to play a key role in adding capacity to African grids. In order for private investment to be attracted to the power sector, however, public sector capacity must be enhanced. How this will be achieved in the next cycle of reforms is still somewhat unclear. What is clear is that unless frameworks are effectively geared to achieve the required synergy to promote mutual partnerships between the state and the market, the next round of reforms will be no more successful than the last.

2.3 Independent Power Producers

Second to state owned utilities, independent power producers are major players in the African electricity generation sector. Called, in part, to plug the shortages in capacity, they also assist in relieving governments of their obligations for financing investment. As previously stated in Section 2.1, the introduction of IPPs was seen as a step towards the standard model of reform towards wholesale competition amongst a number of generators, since private producers would eventually compete in the generation power market. This section of the literature review examines some of the obstacles to IPPs entering emerging power markets as they contribute to the problem of insufficient capacity, and considers ways to promote private investment in generation and improve its outcomes.

2.3.1 Attracting Private Investment into Generation Infrastructure

While many stakeholders are involved in private infrastructure development projects, the concerns of international - and to a lesser extent domestic - investors have been prominent in emerging power sectors. To ensure that the sector remains sustainable, governments have to be in tune to their needs and interests in order to continue attracting investment from this limited source. The broad investment climate that would attract foreign direct investment (FDI) and investment in general is a strong determinant for attracting private investment in generation. Policy formulation and implementation, domestic financial systems, international trade and financial markets, the labour market, public infrastructure, tax systems, legal and regulatory frameworks and governance ultimately affect the progress of market-oriented reforms and the attraction of FDI (Loayza and Soto 2003). In general, a good investment climate with sound regulatory governance and reliable infrastructure bodes well for attracting investment since it reduces the cost of doing business in that country (Dollar, Hallward-Driemeier et al. 2004). In addition, where important public interests are at stake and market forces are weak, strong government institutions are an essential prerequisite for successful private sector participation (Jacobson and Tarr 1995).

The African region, however, generally has been unable to achieve the conditions that would facilitate and attract sufficient amounts of private investment in generation infrastructure. Africa has relatively poor investment attractiveness compared to other developing regions. Roughly a third of countries on the African continent are rated for their investment attractiveness and only four countries have investment grade ratings according to the three major ratings agencies, Fitch, Moody's and S&P (Kotecha 2005; Sheppard, von-Klaudy et al. 2006). Poor investment climates, in general, have contributed to the lack of investment specifically in infrastructure where costs are sunk and returns are amortised over a long period of time.

Around forty IPPs have been developed in Africa. Mostly complementing state-owned generators in providing electricity, they provide less than 9 per cent of generation capacity.⁴⁰ Despite being an important source of new generation in many African countries, this modest contribution is concentrated in a few countries on the continent with Côte d'Ivoire, Egypt, Ghana, Kenya, Morocco, Nigeria, Tanzania and Tunisia accounting for roughly 80 per cent of

⁴⁰ This figure is based on IEA (2007) data which puts installed capacity at roughly 107GW and the author's calculations of IPP capacity in Africa.

installed IPP capacity (Gratwick and Eberhard 2008). The small percentage of IPP capacity attracted in Africa is indicative of the challenges that most African countries (along with other less endowed developing nations) face in bringing in investment, even though there is such a huge demand for power.

Despite the flurry of interest in developing regions and activity from investor utilities in industrialised countries in the 1990s, a 2005 survey showed that three out of four investor utilities in the US and more than four out of five European investor utilities intend to remain focussed in their home regions (PWC 2005:11). Investors have faced many obstacles in realising satisfactory returns on their investments and disappointing investment experiences in some emerging markets have led many investors to retreat from IPP investments in developing countries, including Africa.⁴¹ The decline in private investment in generation infrastructure over the decade from 1998 to 2008 has been driven by a number of factors, the principal ones being the effect of economic crises in developing countries, the unfinished reforms which has meant that infrastructure business has not been placed on a commercial footing (Tenenbaum and Izaguirre 2007), underdeveloped local capital markets in most developing countries⁴², the deteriorating financial position of many sponsors (Rigby 2004), growing concerns over re-nationalisation, and disappointing returns on some projects due to renegotiations (Izaguirre 2004a). There is also recognition that ways in which project risks were allocated has left stakeholders such as governments, investors and consumers, unnecessarily exposed (Izaguirre 2004b). The cases in this thesis will show how some of these issues have played out in the countries, such as deteriorating financial positions of sponsors, which has resulted in equity changes in projects in all four of the countries that have been investigated in this thesis, as well as the project risks which have left consumers and governments exposed in the cases of Ghana and Morocco.

2.3.2 Key IPP Risks

While certain risks in developing IPPs may have been well managed through traditional means, it is clear that traditional risk management mechanisms were inadequate to cater for

⁴¹ Governments also continue to face challenges in dealing with fundamental policy problems and creating an environment in which private investment can flourish while the development needs of countries are achieved.

⁴² The absence of domestic capital markets for infrastructure in most African states has meant increased risk premiums by way of higher interest charges to offset inflation and volatility in domestic currencies.

all risks in reforming emerging power markets and experience suggests that some risks may have been overlooked. Below is a brief overview of three key risks that investors view as most significant deterrents in investing in electricity infrastructure in developing countries according to two independent surveys conducted (Lamech and Saeed 2003; PWC 2005).⁴³ Presented are brief descriptions of the risks; the traditional ways in which they were managed, and prospects for improved risk management of these investor concerns.

a) Expropriation Risk

Infrastructure investments are sunk costs – investors cannot use their assets in other locations and investments are irreversible. Not only are the costs sunk, it also takes a long time for investors to recoup their investment outlays. Over such long time periods investors face numerous risks, one which is having their assets expropriated. Once investors are committed to their projects and the only exit strategies involve huge losses, governments can be tempted not to honour commitments as previously agreed and investors risk becoming victims of expropriation, or what is called obsolescent bargains (Vernon 1971). Since outright expropriation, as in nationalisation of assets, is less common today, investors have recently been more concerned with creeping expropriation, such as the mandatory renegotiation of PPAs.

Robust contracts have generally been used by investors and project sponsors to give themselves legal recourse in the event of expropriation. In addition, government guarantees have traditionally been called on to manage the risk of creeping or outright expropriation. Drawing on government guarantees to attract investors to finance new infrastructure as a way to appease investors may appear appealing to host governments because without having any immediate costs, the government can benefit from the investment. Experiences in developing countries have shown that despite these legal measures, contracts have often been insufficient in keeping expropriation at bay. A study initiated by Stanford University's Program on Energy and Sustainable Development (PESD) analysed the outcomes of private investment in generation infrastructure and found that contracts which evaluated risk *ex-ante* and made provision for it through the legal conventions fared poorly in anticipating risks and specifying solutions (Woodhouse 2005c:48-51).⁴⁴ Out of the sample of independently contracted plants a

⁴³ These are also key risks that were the causes behind many of the renegotiations in IPPs.

⁴⁴ The study closely examined 33 greenfield independent power projects of varying sizes, fuel sources and technologies in 12 different countries in various geographic regions, with varying power sector and country contexts.

third of the project contracts between governments and IPPs had undergone mutual renegotiation and roughly a quarter of the contracts faced unilateral renegotiation or non-payment – amongst these were slightly more than a tenth of the sample that ended in litigation or arbitration.

Even where agreements contained government guarantees, the above study found no evidence of outcomes having a bias toward the guarantee risk provision⁴⁵. A classic example is the case of the Dabhol IPP in India that received overlapping guarantees from central and provincial governments as well as a guarantee for part of the project from the federal government along with a series of letters of credit and escrow arrangements (Lamb 2006). Despite these seemingly robust measures, the security arrangements still proved insufficient. Evidence from the Stanford study showed that while contractual measures are necessary conditions to defend the financial and operational terms of the projects, they are not sufficient in themselves since not all risks can be mitigated through contracts and there is often little certainty as to the ability of contracting parties to uphold their end of the contractual bargain, depending on the intensity of the issues that are stressing the agreements. Reneging on contractual agreements and guarantees has also dented the image of governments and, in many cases, has deterred investors from making future investments.⁴⁶

b) Currency Risk

Currency risk remains a key consideration for investors and governments in IPP development. While foreign investors are notionally shielded from currency risk when PPAs are denominated in hard currency, in reality they share a large part of the risk when local

⁴⁵ In many cases, governments have issued guarantees but have failed to manage the risks they have guaranteed. They do not allow generation costs to be passed through in the tariffs; manage the country's macroeconomics in ways that undermine off-taker's ability to service PPA charges; and institute changes that lead to significant decreases in the value of domestic currency.

⁴⁶ Irwin (2007:4) cautions on the use of guarantees by governments and states that good outcomes with respect to guarantee decisions are more likely under the following conditions: when an effective framework for judging when a government guarantee is employed to justify the use of a guarantee; governments or their advisors know how to estimate the cost of the guarantee; and when decision makers in governments follow conventions that encourage careful reflection of the guarantee's costs and benefits. As an alternative to government guarantees, although mainly used in the oil sector, the use of securitisations or asset-backed securities in electricity sectors could be considered due to the interest reducing benefits that it has on debt in countries that are rich in fuel or mineral exports (Ketkar and Ratha 2001).

currencies in developing countries undergo significant devaluations. Currency risk could easily be compounded by political risk leading to creeping expropriation when governments find it politically difficult to pass on the increased costs and decide to renegotiate IPP contracts. IPP contracts extend over many years, sometimes up to 30 years, leaving stakeholders open to lengthy periods of exposure.⁴⁷ It is for this reason that the development and strengthening of local financial systems should not be underestimated for exchange rate risk mitigation where banking systems become independent of government and gain experience in long-term and structured finance (OME 2003:81).

A gradual devaluation in local currency over a number of years could be managed successfully in most cases, but serious problems are created when the decline is precipitous as IPP investors found in South Asia and in Latin America during the financial crises that gripped markets in these regions.⁴⁸ Currency devaluations are normally coupled with higher interest rates which affect economic growth and subsequent demand for contracted power which could lead to power planning problems due to a reduction in anticipated power. It could also stall other projects in the pipeline that have to be re-evaluated to incorporate increasing costs as a result of both devaluations and higher interest rates.

Since the majority of investments are made in foreign currency exposing shareholders and creditors to currency risk, creditors, in particular, often seek out ways to shape the contractual arrangements to pass this risk onto governments or consumers. The state's presumed influence over currency risk is often stated as a factor when arguing for allocating this risk to governments. Interestingly, a different view has been proposed by Gray and Irwin (2003b) who suggest that investors take on all the financing related exchange rate risk even though it may translate into higher tariffs for consumers as a premium for bearing such risk. They support their proposition by arguing that government's financial positions are affected in

⁴⁷ Gray and Irwin (2003a) observed that in the 25 years prior to 2003, developing country currencies lost on average 72 per cent of their value relative to the US dollar. Roughly a fifth of developing countries' currencies lost more than 99 percent of their value. The Brazilian real and the Argentinean peso lost almost all of their value between 1985 and 1990, and the Indonesian rupiah lost roughly 80 per cent of its value in 1997 and 1998, which impacted on utilities' abilities to pay charges.

⁴⁸ In the Philippines widely publicized renegotiations followed the devaluations in currency. In Malaysia and Thailand, while the dozen plus IPPs faced some pressure during the Asian financial crisis, local capital sourced almost entirely from domestic markets as output was sold under long-term local currency denominated contracts to the national utility, helped reduce financial strain on the power sector and continued to ensure healthy profits for IPP investors (Rector 2005; Woo 2005).

complex ways and by many factors unrelated to infrastructure projects, and because governments' responses to financial incentives differ from those of firms and individuals. They do recognise, however, that the problem could be foregrounded in the longer term when too much foreign currency debt is taken on as experienced in the Philippines where more than forty long-term contracts were signed (Woodhouse 2005a)⁴⁹. In cases where competitively priced plants have kept power charges low and privately contracted power represents a smaller percentage of the country's generation, currency devaluations have been less of a problem, as in the case of Egypt where significant currency devaluation occurred in 2002 and 2003 (Eberhard and Gratwick 2007).

c) Regulatory and Political Risk

Another major barrier to investment in developing countries is the perceived threat of regulatory risk (Jamison and Holt 2005; Newbery 2006:16-17). Changes to an initially agreed legal framework that governs investment in electricity infrastructure could spell a potential loss of income to investors. If regulatory capacity is weak or the framework is viewed as unpredictable, foreign and domestic investors are deterred from committing their money. Firms with international equity investments in power sectors in developing countries often stress that the conditions essential to success are the rule of law, respect for investor's rights, as well as legal and regulatory processes that are free from government interference (Lamech and Saeed 2003).

Power plants, because they sell an important and highly visible commodity that is viewed as a public good, are particularly exposed to social and political risk. Because many developing countries have a long history of subsidised tariffs, PPA charges are often highly politicised in poorer settings where consumers are expected to pay the full cost of service provision. While effective regulation is able to have an important impact on the performance of the sector and the economy, no perfect regulatory reform models exist indicating potential problems especially for investors finding themselves in nascent regulatory environments (Alexander and Estache 1999:25-26). Even with independent regulation, objectives can conflict as regulators have to consider the socio-political impact (increased tariffs and potential political instability) of attempting to make the sector attractive to investors (Mwenechanya 2005).

⁴⁹ The disruption by the Asian financial crisis had a significant impact on IPP power purchase agreements in the Philippines, making the take-or-pay contracts unsustainable. During and after the crisis, the government continued to honour the contracts until 2001 when a new legal requirement mandated the review of PPAs leading to contract renegotiation efforts in the IPP sector (Woodhouse 2005a).

Regulatory and political risk insurance has been employed in many cases as means to isolate private investors from this risk. The Multilateral Investment Guarantee Agency (MIGA) provides political risk insurance cover for most types of political risk (ADB 2004; World Bank 2007) and the World Bank's Partial Risk Guarantee (PRG) is extended to cover many of the legal regulatory and contractual risks (Gupta, Lamech et al. 2002).

Power sector reform, in itself, can contribute to regulatory and political risk. While addressing underlying policy problems is an ideal to be achieved by governments, policy goals in search of improved sector performances, as reforms evolve, could impact investment negatively. Power sector reform is an evolving process and changes instituted as part of reforms could hinder and slow down the reform which was intended to encourage further investment (Lovei 2000). This could be the case when IPPs have to be incorporated into wholesale power markets and existing contracts have to be integrated into evolving market arrangements as power sectors move toward the 'standard prescription' and take-or-pay contracts do not allow a framework for competition in the market (Woolf and Halpern 2001).⁵⁰ In the case of Morocco in Chapter 5, this difficulty has resulted in dual regulated and non-regulated markets operating side by side being proposed to deal with the intricacies of integration. Although the Moroccan proposal does not deal with integration in the long-term, no further longer-term plans have been documented beyond the proposal on dual markets. Despite the plans for the dual market, implementation is at least three years behind schedule, depicting the intractability and complexity of moving on with reforms involving integration.

The abovementioned risks are generally viewed by project sponsors as the most applicable in investing in reforming developing regions. There are, however, additional risks that have also contributed to stalled negotiations, delayed construction times, or cancelled projects. Table 2.2 below gives an overview of some of the risks that both investors and governments face during the development of power generation projects and some proposed mitigation techniques which could be employed to moderate the possibility of adverse outcomes. In the empirical cases that follow, many of the risks mentioned below will re-emerge, along with the varied experiences of how governments and power sectors fared in managing them.

⁵⁰ Impediments in integrating IPPs into markets delays the scope for competition and could result in large resource costs for countries if plants are dispatched out of merit order (Woolf and Halpern 2001:2).

Table 2.2: Independent Power Project Risks

Phase	Risk	Proposed Mitigation Mechanism
Project Preparation	Conflicting or lack of decision-making authority, changes in authorities (elections),	Develop a strong institutional and implementation framework
	Delays in approvals or failure to obtain approvals, permits and licences	Develop a strong institutional and implementation framework
	Inadequate or inappropriate legal structure for project finance	Legal reform
	Resistance and protests by interest groups such as NGOs, unions, etc	Cooperation and integration of stakeholder concerns
	Bidding risks	Interest in project bidding should be maximised
	Legal challenges to the awarding of project	Develop and use transparent award procedures
	Environmental risk	Perform comprehensive Environmental Impact Assessment (EIA), comply with lender guidelines such as the World Bank, external monitoring
	Technological risk	Preference for proven technology and a reputable constructor. New technology should be allowed on the basis that technological guarantees and assurances are provided
	Delays in financial closure	Deadline should be realistic
Project Construction	Cost overruns and completion delays	Preference should be given to fixed-price turnkey contracts. Penalty clauses and performance incentives should be used to prevent delays
	Failure to meet performance specifications	Make provision for clauses in contracts
	Changes to approvals, permits and licences	Negotiation with relevant authorities or arbitration
	Failure to complete supporting infrastructure (transmission links, roads, fuel delivery)	Strong coordination with counterparties
	Unforeseen delays	Make provision in project agreements
	Force majeure	Make provision in project agreements, multilateral guarantees
	Default by contractors or equity holders	Invoke shareholders' agreements or step-in rights
	Liability risks	Take out private insurance
	Strikes and demonstrations	Take out private or multilateral insurance
	Expropriation or nationalisation	Compensation clauses and multilateral insurance
Project Operation	Demand risk	Perform independent and accurate demand forecast, use take-or-pay contract
	Supply risk	Robust fuel supply contract with a number of credible suppliers
	Payment risk	Make escrow facilities, letters of credit and other credit enhancers a requirement
	Breach of contract by off-taker	Government guarantees, litigation and arbitration
	Government guarantee withdrawal	International arbitration
	Inadequate price adjustment mechanisms, changes to contract, creeping expropriation	Independent regulation, international arbitration
	Change of law	Government guarantees
	Exchange rates, interest rates and inflation movements	Use hedging, user charge indexation and contract extension mechanisms
	Foreign exchange availability and convertibility	Arrange for agreements with Ministry of Finance or government guarantees

Sources: Sader (2000), World Bank/USAID (2004) , Naidoo (2005)

As far as possible, project risks, including construction and project risks, should be identified and risk management strategies agreed upon at the project preparation stage due to the difficulties involved in altering agreements once all the stakeholders are in agreement with the terms, especially when the change involves certain parties shouldering more risk than originally agreed on. Generally, risks during project construction have been relatively better managed in turnkey IPP projects partly due to the short construction periods (relative to the operation phase) and the intense negotiations which precede this phase with a strong focus on project construction and commissioning.⁵¹ Risks during the project operation stage, due to the long duration of this phase of the project, can vary over time and it is here that a number of eventualities (internal or external to the project) can threaten the sustainability of the IPP. An example of note is the fuel risk in Tunisia's second IPP in Chapter 6, where fuel availability posed as a serious problem after operations had already started and threatened the project's source of revenue.

2.3.3 Managing IPP Risks

As already described in this chapter, the problem of attracting investment into power sectors is strongly linked to the real risks and the risk perceptions of investors. There are a number of risks that are present in developing infrastructure projects in general, and with private generation projects the intricacies and complexities of the arrangements required to achieve the success of projects can easily become more complex. The continuous search for optimal risk management techniques has contributed to shaping the risk management strategies employed by stakeholders in private generation infrastructure investments. Continued difficulties in dealing with risks often result in projects being distressed; delays in contracting the much-needed new capacity; or even outright cancellation of planned projects (Harris, Hodges et al. 2003). Certain risks are particularly tricky to manage due to insufficient market instruments and related mechanisms to cater for risks in developing country settings (Dailami, Lipkovich et al. 1999:1; Malgas 2002; Auffret 2003).⁵²

⁵¹ The use of reputable, well-experienced project developers has also reduced construction risk.

⁵² Due to the relative undeveloped power pools, power markets have not developed as in industrialised countries. With relatively few players and with a regional shortage of capacity in these pools markets, Contracts-For-Differences and other derivative instruments, for example, do not exist. The scope of uncertainties on exchange rates and weather-related effects (such as droughts) would make insurances for electricity supply difficult to quantify and underwrite. Although there are insurances offered by multilateral agencies for certain risks (as in certain categories of political, regulatory and force

Privately sponsored power plants are usually developed and financed through special purpose vehicles on a limited recourse basis, a structure that is exposed and sensitive to many uncertainties. The means to cater for these uncertainties are woven into a complex web of contracts and agreements. Once a project sponsor has reached an agreement with a government that specifies the details of the project, the sponsor needs to obtain all relevant licences, approvals and clearances from other national, provincial and local government entities such as the power purchase agreement, land titles and environmental clearances, construction permits, tax agreements, import permits, fuel supply agreements, foreign exchange convertibility and transferability agreements, immigration permits, and specific government guarantees (Sader 2000:23-24). In addition, the project sponsor has to finalise agreements with other private parties that would support the construction and operation of the project such as engineering procurement and construction (EPC) contractors (normally on a turnkey basis) as well as operating and maintenance (O&M) contractors, before the project can reach financial closure involving contractual arrangements with other investors, multilateral, bilateral or commercial lenders, insurers, and export credit agencies. These multifaceted contractual structures engage many different players whose collective expectations require conceiving an arrangement that is acceptable to all parties by meeting different objectives and incentives. The interaction and nature of the contracts motivate the financing choices and inform governance arrangements for these investments, as the project allocates contracted and non-contracted risk between different stakeholders (Dailami and Hauswald 2001:3-4). Efficient risk allocation means allocating corresponding risk factors to the party that is best suited to exercise the associated real options to manage the risk (Bettignies and Ross 2004:139; World Bank/USAID 2004:134-139; Irwin 2007:60). Where returns on investments can be adjusted to cover underlying risks or the risks can be reduced to meet lower returns, attracting private capital becomes possible (OME 2003:28). In many cases, however, investors deem returns to be insufficient for the risks that they assume. In such cases, projects may be stalled or cancelled outright if stakeholders feel uncomfortable with the risks that they are expected to bear by other parties.

2.3.4 Alternative Approaches to Attracting Investment into Generation

While the challenge is for investor firms and governments to find mechanisms that reduce risk and manage them in ways that are cost-effective and relatively trouble-free, the complication

majeure) many governments do not want to be saddled with contingent liabilities. In the absence of such guarantees, there are few similar offerings on the market to hedge against these kinds of risk.

is that each country is different and that varying country contexts set their unique backdrops for how risks present themselves and, ultimately, the outcomes of projects. Broad conclusions about risks and how they relate to project outcomes are, therefore, often difficult to apply in specific settings. In addition, although surveys among large sample sizes of private infrastructure projects such as those performed by Lamech and Saeed (2003) and PWC (2005) generate broad conclusions about risks and indicators of IPP experiences, they are often tricky to quantify and compare systematically. Hence, there has been a need for alternatives to traditional risk management in improving IPP outcomes for investors and host countries. Three alternatives are discussed below.

a) Risk Compensation and Risk Reduction

Governments can attract private investment in infrastructure in two broad ways (Dailami and Klein 1997:20; Klingebiel and Ruster 2000:2). Firstly, they can offer financial support to investors in the form of grants, low-interest loans and guarantees in order to compensate for risks involving low tariffs, insolvent SOEs, unstable macro-economic conditions, and other problems. Secondly, they can address the underlying policy problems that trigger investors' concerns by ensuring macro-economic stability, raising tariffs to more viable economic levels, and establishing sound policy and regulatory frameworks. Although both methods can attract investment, the former tends not to reduce overall costs but to allocate them to captive taxpayers, while policy reforms aspire to improve project fundamentals and make them attractive to investors without unnecessarily imposing costs on taxpayers (Klein 1996). The latter approach is by its nature more sustainable and, hence, has been the path considered by most governments, including those in the four country cases investigated in this thesis, albeit with varying outcomes, due to the unique challenges that have been encountered reforms.

b) Flexibility and Strategic Partnerships

Setting out to draw specific conclusions on IPP investments in specific contexts, Stanford University's Program on Energy and Sustainable Development assessed a range of independent variables that would explain the variation in private investment outcomes for greenfield IPPs (Victor, Heller et al. 2004).⁵³ In addition to strategic risk management

⁵³ The Stanford study identified the universe of countries that have IPPs and selected a sample of countries that have a variation in the factors that may explain success or failure of projects and a variation in the role that IPPs play in the power sector. The study closely examined 33 greenfield independent power projects of varying sizes, fuel sources and technologies in 12 different countries in various geographic regions, with varying power sector and country contexts. The Stanford IPP study focussed on IPP outcomes from two perspectives: an investment perspective to assess the extent that

practices helping to structure projects in ways that reduced their vulnerability to risks, the study linked future successes to more flexible contract parties or stakeholders, since goodwill *and* legal contracts sometimes go further in resolving problems when deals come unstuck than do contracts on their own. In this way, the willingness of stakeholders to make concessions generally could lead to more beneficial outcomes in the longer term (Woodhouse 2005c:64).

The ability to manage counterparty risk, especially during politically sensitive periods which may lead to renegotiation, is also considered indispensable to preserve successful outcomes (Woodhouse 2005c:67-75). Here, local partnerships prove to increase substantially the likelihood of successfully mitigating the political risks which are often inherent in foreign-owned investments (Woodhouse 2005c; Eberhard and Gratwick 2007). With local partnerships the ability to manage fuel supply, dispatch, non-payment and renegotiation were increased and were often proximate determinants of project outcomes when these stresses threatened operations and the sustainability of the projects. In Morocco's third IPP (discussed in Chapter 5), where the national utility was the local partner with the largest shareholding in the plant, the project enjoyed government support to the extent where the state assisted in arranging local financing from local Moroccan banks to manage the currency risk on the project.

c) Balancing Investment and Development Outcomes

In a study of African IPPs by the University of Cape Town's Management Programme for Infrastructure and Regulatory Reform (MIR), the investment and development successes of IPPs was found to be attributed to project level factors as well as factors related to the host country.⁵⁴ The study tests a hypothesis that balanced investment and development outcomes lead to more sustainable projects. The assumption was that if investment and development outcomes were in balance and both investors and off-takers were satisfied with the project arrangements and their investment and development outcomes respectively, private investment would continue to grow. The investigation found that indeed a balance between investment and development outcomes leads to the sustainability of projects within the

investors' expectations were met by the project, and a development perspective to determine the degree to which the project met the expectations of the host country.

⁵⁴ Drawing from the methodology and research framework of the previously mentioned Stanford study and using project and country level factors as independent determinants of outcomes, the study makes a departure from the Stanford PESD IPP study by seeking to determine the extent to which project and country related factors make projects sustainable, and creates a direct link between these factors and the investment and development outcomes.

context of the conditions that existed when the projects were developed, even if the balance was achieved with time and, in some cases, only after renegotiation as evidenced in the case of Kenya (Eberhard and Gratwick 2007).⁵⁵ Perceived imbalances often intensified by exogenous stresses lead to contracts becoming unstable and even renegotiated despite the security arrangements which could prove insufficient to sustain the contracts. In most cases, the incidences of contractual problems did not necessarily imply the end of the project, but lead to a search for a new equilibrium in balancing outcomes that proved more sustainable.

Table 2.3 details the project level factors that were cited as contributing to the outcomes of IPPs. Control of these factors are largely considered to be within the purview of the project sponsor and contain elements such as favourable equity partners, debt arrangements, the means to secure revenue, credit enhancements, strategic risk management measures, good technical performance, and strategic management and relationship building. Like the Stanford study (as described in section 2.3.3.1), the MIR investigation establishes a link between favourable equity partners and the development and investment outcomes for African IPPs. Links were established between favourable debt arrangements and project successes since the financing mix and type could have implications for the financial sustainability of the projects, especially when local currencies devalue. Closely related to financing, the means to secure a revenue stream for investors (mainly through the financial viability of the off-taker) also impacted on the successes of projects. Since revenue payments are contractually linked to plant technical performance, plant availability and dispatching was also linked to project outcomes. Lastly, ongoing strategic management and relationship building have proved to be helpful when projects face obstacles for which no provisions were made contractually. These contributing elements to the success of IPP projects are themes that will feature in the empirical cases for this thesis from Chapters 3 through 6.

⁵⁵ After the end of the PPA terms for Iberafrica (an initial stop-gap IPP) and OrPower4, both privately owned plants agreed to reduce capacity charges in order to secure PPAs for a second term. Prices became more competitive with that of the state-owned generator, KenGen, which contributed to more positive development outcomes for Kenya (Eberhard and Gratwick 2007:24).

Table 2. 3: Project Level Elements Contributing to IPP Outcomes

Contributing Elements	Details
Favourable equity partners	<ul style="list-style-type: none"> -Local capital/partner contribution, where possible -Risk appetite for project -Experience with developing country project risk -Involvement of a DFI partner (and/or host country government) -Reasonable, fair ROE -Development-minded firms
Favourable debt arrangements	<ul style="list-style-type: none"> -Low cost financing -Local capital/markets mitigate foreign exchange risk -Risk premium demanded by financiers or capped by off-taker matches country/project risk -Some flexibility in terms and conditions (possible refinancing)
Secure and adequate revenue stream	<ul style="list-style-type: none"> -Commercially sound metering, billing and collections by the utility - Robust PPA (stipulates capacity and payment as well as dispatch, fuel metering, interconnection, insurance, <i>force majeure</i>, transfer, termination, change of law provisions, refinancing arrangements, dispute resolution, etc.) - Security arrangements where necessary (escrow accounts, letters of credit, stand-by debt facilities, hedging and other derivative instruments, committed public budget and/or taxes/levies, targeted subsidies and output-based aid, hard currency contracts, indexation in contracts)
Credit enhancements and other risk management and mitigation measures	<ul style="list-style-type: none"> -Sovereign guarantees -Political risk insurance -Partial risk guarantees -International arbitration
Positive technical performance	<ul style="list-style-type: none"> -Technical performance high (availability) -Sponsors anticipate potential conflicts (especially related to O&M, and budgeting) and mitigate them
Strategic management and relationship building	<ul style="list-style-type: none"> Sponsors work to create good image in country through political relationships, development funds, effective communications and strategically manage their contracts, particularly in the face of exogenous shocks and other stresses

Source: Gratwick and Eberhard (2008)

Table 2.4 presents the country level factors considered to contribute to the outcomes of IPPs. Control of these factors is largely within the purview of the project sponsor and includes elements such as a favourable investment climate, a clear electricity policy framework, impartial, transparent and consistent regulatory oversight, coherent power sector planning, competitive bidding practices, secure contracts and the abundance of low-cost fuel. Again, similarly to the Stanford study, the MIR investigation considered the role of a favourable investment climate in attracting IPPs. It established a link between clear policy and credible regulatory frameworks and positive IPP outcomes. Since regulatory and policy risks are concerns for investors, it is beneficial for these frameworks to be enshrined in legislation, i.e., policy is clearly spelled out and regulatory decisions are transparent to command investor confidence. The study considers the extent to which power sector planning had impacted on IPPs, i.e. has the planning (or lack thereof) facilitated or obstructed the entry of IPPs. Lastly, it found that the presence of domestic fuel plays a part in reducing IPP costs and reduces the

chances of renegotiations due to high prices when conditions change. Thermal IPPs are highly exposed to fuel market conditions, and plants that have been able to secure a fuel supply that was cost competitive and reliable have been able to minimise fuel risks (Woodhouse 2005c; Gratwick and Eberhard 2008).⁵⁶ In two of the four cases presented in this thesis, it was found that the countries with domestic fuel sources for power generation, namely Côte d'Ivoire and Tunisia, had in fact been less exposed to fuel risk and proved to have adequate generation to meet their domestic demands.

The MIR study has therefore made a contribution by identifying various factors (shown in Tables 2.3 and 2.4) that contributed to IPP outcomes for investors and off-takers and appear to make investment in independent power projects more sustainable.

⁵⁶ Even in Africa, countries that have their own source of fuel have traditionally been more successful in maintaining lower charges for power from IPP such as Egypt, Côte d'Ivoire and Tunisia.

Table 2. 4: Country Level Elements Contributing to IPP Outcomes

Contributing Elements	Details
Favourable investment climate	<ul style="list-style-type: none"> -Stable macro-economic policies -Legal system allows contracts to be enforced, laws to be upheld, arbitration -Good repayment record and investment grade rating -Requires less (costly) risk mitigation techniques to be employed which translate into lower cost of capital and hence lower projects costs and more competitive prices - Potentially more than one investment opportunity
Clear policy Framework	<ul style="list-style-type: none"> -Policy framework enshrined in legislation -Framework clearly specifies market structure and roles and terms for private and public sector investments (generally for single buyer model, not, yet, wholesale competition in African context) -Reform-minded ‘champions’, concerned with long-run, lead and implement framework
Clear, consistent and fair regulatory oversight	<ul style="list-style-type: none"> -Transparent and predictable licensing and tariff framework improves investor confidence -Improves general performance of private and public sector assets -Cost-reflective tariffs ensure revenue sufficiency -Consumers protected – improves development outcomes
Coherent power sector planning	<ul style="list-style-type: none"> -Energy security standard in place; planning roles and functions clarified -Power planning vested with lead, appropriate (skilled, resourced and empowered) agency -Power sector planning takes into consideration the hybrid market (public and private stakeholders and their respective real costs of capital) and fairly allocates new build opportunities among stakeholders -Planning has built-in contingencies to avoid ‘emergency power’ or blackouts
Competitive bidding practices	<ul style="list-style-type: none"> -Procurement process is transparent and competition ultimately drives down prices
Abundant low cost fuel & secure contracts	<ul style="list-style-type: none"> -Cost-competitive with other fuels -Contract safeguards affordable and reliable fuel supply for duration of contract

Source: Gratwick and Eberhard (2008)

In summary, African countries have not been able to adequately allay the concerns of investors and this has contributed to insufficient investment and a shortage of capacity in the African power sector. The challenge is to find improved mechanisms to deal with the risks faced by investors and governments (Besant-Jones 2006:72) or be prepared to pay higher risk premiums for the higher perceived risks. Failing this, the problem of insufficient investment will persist.

2.4 Electricity Planning and Procurement

The importance of electricity planning lies in its role in helping governments and utilities to recognise opportunities and avoid costly mistakes. It enables planners to grasp more clearly what they want to achieve, and when and how they can achieve it. With power sector reforms a rearrangement of institutional functions often resulted in the planning function being taken away from the state-owned utilities and assumed by sector ministries or related agencies. Reformers often assumed that new generation investments would be taken care of by the market and did not explicitly focus on the issue of planning. The necessity of planning under hybrid market and various single buyer arrangements remained even more obscure. Planning often turned out to be inadequate leading to delays in building power plants and consequently insufficient generation capacity.

In the past, the national state-owned utility assumed sole responsibility for generation expansion planning. But with the entry of IPPs, it was not often clear whether the SOE remained the supplier of last resort. Planning functions were often neglected or were transferred to the Energy Ministry which often had insufficient capacity to plan effectively. Weak or absent regulatory and governance frameworks for generation planning and procurement undermine the credibility of investment and contracting decisions and there are often no clear linkages between generation planning, the timely initiation and implementation of tender processes, and commercial operations of new generation plants.

In reviewing the literature on electricity planning as it relates to the problem of insufficient generation capacity, this section evaluates why reform efforts have largely ignored these issues. It further explores the links between planning, procurement and contracting and how the emergence of hybrid markets creates new challenges in terms of allocating institutional responsibility and capacity for these functions.

2.4.1 Electricity Planning

The purpose of generation planning is to determine the amount and type of generation capacity to be constructed, and the time in which it needs to be constructed and commissioned, while the total cost to the utility is minimised (Kagiannas, Askounis et al. 2004:414). Energy security is important in the modern age due to its links to economic and social development. Energy security is reduced when countries hold inefficient generation portfolios that are unnecessarily exposed to fossil fuel price volatility or drought (Awerbuch

2006), suggesting that generation planning should not be performed in isolation. Reliable planning scenarios for the electricity industry are often dependent on upstream fuel industries that have different drivers and constraints for quantity, price, and quality of supply to that of the ESI. Effective resource allocation, co-ordination and supply projections are, therefore, necessary between electricity and upstream industries (Harris and Davies 1980:28). If electricity planning fails to adequately consider the links to upstream supply industries, such as fuel markets and equipment suppliers to support power plants, or to downstream links, such as transmission expansions required to evacuate the power generated, and to demand patterns, it could result in undesirable consequences. It is, therefore, essential for planning to encompass an integrated approach to supply and demand-side additions, constraints, and requirements.

2.4.1.1 From Conventional Electricity Planning to Integrated Resource Planning

Traditional electricity planning focussed on supply side additions to generation infrastructure to meet the anticipated demand and minimise economic costs of expansion (Anderson 1972; Auer 1974). Until the 1970s, the supply of low-priced energy and resources helped sustain world economic growth and the traditional approach to energy planning was developed against this background (DeOliveira and Girod 1990:530). Traditional planning often relied on increased economies of scale in generation capacity with little consideration of the need for greater energy efficiency. Consumers generally absorbed the costs of expansion and the holding of large reserve capacities, often with little choice (Dickel 2003). One of the primary reasons for energy planning having a one-sided supply focus was because energy planning was not extensive; planning objectives evolved separately within the various energy sub-sectors and individual enterprises (Eberhard 1992:2). The energy sector was dominated by engineers who had a supply focus. However, after the oil shocks of the 1970s, increased supply costs, led to a greater focus on least-cost utility planning. Least-cost expansion has evolved toward integrated resource planning (IRP), which allows for broader economic, environmental and social objectives to be integrated in electricity planning.⁵⁷ IRP goes

⁵⁷ Electricity costs normally exclude the external costs imposed by society. These costs can be in the form of air and water pollution, exposure to volatile fuel markets and worsening trade balances that increase debt to other countries (Michelfelder 1993:228). In a study of electricity costs and externalities in South Africa, Spalding-Fecher and Matibe (2003) estimated the external costs of electricity based on quantitative analysis of air pollution impacts of human health, damages from greenhouse gas emissions, and the avoided health costs from electrification, at approximately 40 and 20 per cent of

beyond supply side technologies to include energy efficiency and demand-side management (DSM) technologies, amongst others, to ensure a balance between supply and demand in future planning scenarios.⁵⁸

The boundaries of energy planning are, therefore, no longer fixed by the energy sector but by the energy system as a whole and the linkages between sectors and with the broader economic and social environment (DeOliveira and Girod 1990:531).

Within integrated resource planning, demand-side options are just as important as supply-side options. The Electric Power Research Institute (EPRI) has shown that in some cases DSM can cut demand by more than 50% (Hirst and Goldman 1991:109). In a study conducted by Hill (1999:4), it was estimated that the Chinese island of Hainan could shave off as much as 80 per cent of its 1992 peak by 2000 by investing in cost-effective DSM programmes. Another study employing integrated resource planning by Volpi, Jannuzzi and Gomes (2006) presents the view that with more aggressive measures for reducing energy wastage at the production and consumption levels and promoting renewable energies, Brazil could reduce its projected power demand by 38 per cent by 2020 avoiding 74.6 GW of installed capacity and saving US\$15 billion.⁵⁹

2.4.1.2 Why the Promise of Integrated Planning Fell Short of its Potential

Before power sector reforms were initiated in developing countries few African countries included IRP in a rigorous way in power sector planning or even used it as a means to compare supply and demand side options. Although many developing countries have

industrial and residential tariffs, respectively. In this regard plant location, technology and fuel choices have become ever more important in generation investment decisions (Hirst and Goldman 1991:98).

⁵⁸ Put differently, the goal of IRP is to match the supply of energy service to the demand of energy services while trying to minimise the quantities and the costs of both. Thus if building additional generation capacity is more expensive than meeting the demand for energy by improving energy efficiency, then energy efficiency improvements should be selected as the resource to achieve the objective of least-cost. Through IRP therefore the difference between supply and demand could be reduced and, more importantly, it could be reduced more cost effectively (D'Sa 2005:3).

⁵⁹ This equates to a saving of 293TWh. The efficiency programme was estimated to create up to eight million new jobs and stabilize Brazil's CO₂ emissions to 2004 levels by 2020 (Volpi, Jannuzzi et al. 2006).

legislated and mustered organisational support for energy conservation, these have generally not been fully integrated into power sector planning (D'Sa 2005:5). Why is it then that, despite IRP holding so much potential to postpone or negate the need for additional generation capacity, it did not play a more central role in energy policy and power sector planning in developing countries? The reasons are numerous.

a) Path Dependence

Traditional rigid master plans developed by utilities and/or energy ministries were infrequently updated and lacked the flexibility required for the modern-day contexts in which power sectors were evolving. Cost estimates are often outdated and timelines for project development unrealistic. With private funding and ownership, long-term economic returns needed to make way for shorter-term financial returns (Munasinghe 1990).⁶⁰ In many cases, however, planning failed to contemplate the evolving needs of power sectors in developing countries, including those in Africa; instead, utilities reacted to energy shortages by contracting stop-gap measures rather than focussing on systematic planning. The electricity crises in certain countries were so acute that, understandably, utilities were more concerned with dealing with immediate crises rather than long-term planning. However, even when power crises were less prevalent, the concept of the traditional one-sided approach was dominant and hard to shake off. Decision-making was based on a supply paradigm that largely sidelined DSM resources and little real consideration was given to energy efficiency as a means to manage the effects of increasing electricity demand and diminishing reserve margins.

b) Preoccupation with Power Sector Reforms

With power sector liberalisation, it was believed that additional generation capacity would be 'left to the market' (Reddy 2005:5). Generation planning therefore became a casualty of market reforms in Africa. However, wholesale competition was not reached and private investment did not take care of capacity expansions, as expected. Power sector reforms aimed to transform vertically integrated monopolies into wholesale and retail power markets and planning was often overlooked or neglected in the process. While many electricity wholesale markets in industrialised countries which were opened to competition have managed to maintain adequate investment in generation (IEA 2003:3), the same cannot be said of

⁶⁰ While capital costs is a key factor that shapes investment choices, technologies that can be installed quickly and operated flexibly in response to market demands have become increasingly attractive to power markets (IEA 2003:3).

developing countries where reform has stopped short of competitive wholesale markets. The emphasis in power sector reform in many developing countries was on unbundling and advancing regulatory frameworks in preparation for the new market. Dealing with difficult ownership transfers, complaints from agitated consumers and objections from discontented labour unions consumed the focus of those in authority, to the exclusion of what were considered longer term issues, including planning (D'Sa 2005:7).⁶¹

c) Poor Institutional Co-ordination

Poor institutional arrangements have also inhibited an integrated planning approach to electricity. Often commitment from senior government officials was lacking and there were rarely institutional vehicles well resourced to take the lead in IRP. Ministry departments or agencies able to influence demand-side factors often operated in isolation from those responsible for supply side capacity planning. D'Sa (2005:7) notes that in India, for example, the Ministry of Power was distinct from the Ministry of Non-conventional Sources of Energy and that these two entities did not draw up integrated energy plans. Hence programmes were planned and implemented independent of each other and there was little co-ordination between supply and demand programmes. In many post reformed power sectors, the planning function is either neglected or is shifted from the national power utility to the Energy Ministry, which often does not have the capacity to undertake the function adequately. Confusion sets in as to who is finally responsible for ensuring that the lights stay on: the old state-owned utility, government or IPPs? Without explicit allocation of planning responsibilities and functions, there is no proper co-ordination and each entity is generally more concerned with its own narrow objectives than integration for overall development of the power sector.

d) Questionable Suitability and Lack of Resources

A belief that was widely held was that IRP would only be useful for developed energy systems in the most industrialised countries where the data, finance, management and skills existed to use it properly (Munasinghe 1990:445). De Oliviera and Girod (1990:529) argued that developing countries have political, financial, social and economic conditions that are distinct from those in industrial countries and, therefore, need different methods of energy

⁶¹ It would also appear that corporatisation and privatisation would lessen the need for IRP for utilities since strategic plans of utilities would be more inclined to deal with narrow shareholder-informed objectives than with the overall benefits of the energy system or even society. Investors would therefore have been unlikely to consider externalities and other benefits that accrue to society if it potentially decreased their own profits (D'Sa 2005:7).

planning.⁶² Even standard capacity expansion models used in industrialised countries were considered ill-equipped to model and compare developing country risks between various projects and generating technologies (Andrews 1995). As a result, demand forecasts in developing countries could be out by far. During the development of India's Dabhol IPP, for example, the growth in electricity demand was projected to be 18 per cent. In reality, the actual demand turned out to be 5.1 per cent (Woodhouse 2005c:75-77; Lamb 2006:51). Moreover, many developing countries lacked the skills, management and finance to use complex computer-simulated generation planning programmes and techniques properly (Munasinghe 1990). In many cases, utilities continued to face severe financial pressure leading to inadequate resources being available for energy efficiency and generation planning, let alone IRP, which was seen as elaborate and a nice-to-have. Integrated resource planning is rather information intensive and energy ministries in many developing countries rarely had the required information to use as inputs to make quality IRP decisions.⁶³

In many cases, planning was limited to indicative planning and failed to include financial, legal, and environmental aspects of generation development. In these cases, although planning appeared adequate on paper, it failed to anticipate the challenges experienced in securing financial resources, equitably allocating project risk and contingent liabilities, evaluating environmental constraints to project development, and assessing the security of fuel supply.

⁶² Developing countries have heterogeneous societies (in comparison to industrialised countries where societies are more homogenous) which make patterns of energy consumption difficult to link to groups of consumers. In addition, energy systems are in many ways still under construction in developing countries making forecasting trickier (DeOliveira and Girod 1990:534). Demand forecasting due to access expansion and demand growth investment decisions is often more uncertain than supply-side investment uncertainty. Planners and policy makers often did not have a firm handle on the factors that impact on growth and patterns in energy demand in order to make credible demand projections and respond to these with appropriate demand and supply-side management policies.

⁶³ IRP is resource intensive because the process is dynamic. This is not only because changes in demand and supply are evolutionary, but because of DSM programmes and supply side alternatives have feedback effects which impact on the process of selecting future planning strategies (Hill 1999).

2.4.2 Power Plant Procurement in Hybrid Markets

Following on from the difficulties associated with planning, delays in procuring new generation capacity also aggravate problems of insufficient capacity. Often, as part of power sector reforms, responsibilities for procurement have shifted from utilities to ministries (or related agencies) with little or no experience in this area. Many governments face serious deficits in the institutional expertise and capacity necessary to implement private generation infrastructure projects. While they may be proficient in technical aspects of infrastructure projects, civil servants often lack familiarity with transactions in project finance and in the complex legalities of elaborate BOOT investments (Sader 2000:32). Generation infrastructure procurement touches on a number of aspects which, if not optimally implemented, can lead to problems and delays in contracting additional capacity. A number of these aspects are described below.

a) Contracting Governance

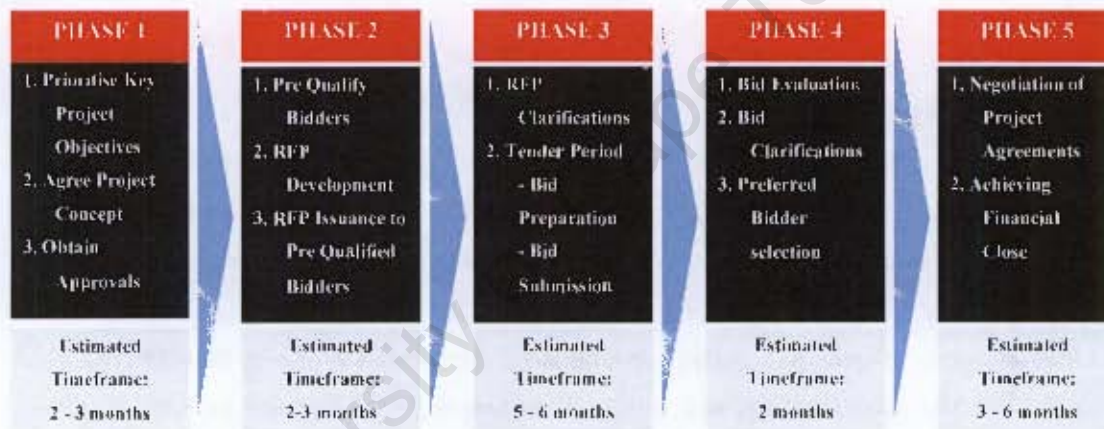
The introduction of IPPs raises questions such as: How should the process of adding generation capacity be arranged? Should competitive bidding processes grant IPPs the right to compete for all future generation? What decision-making processes for procuring generation capacity should be used in the long run? (Roseman and Malhotra 1996). In Africa, there is little evidence of clear and transparent criteria for the allocation of new-build opportunities amongst state-owned utilities and IPPs, and contracting decisions and policies often lack sufficient governance mechanisms. The absence of certainty and transparency tends to result in lengthy and confusing negotiations that delay project development. In addition, many countries in Africa lack independent monitoring bodies to provide oversight of procurement activities. In Ghana, for example, while an independent procurement agency exists specifically for this purpose, the urgency of getting power generation facilities developed in an environment of chronic electricity shortages appears to have exempted the power sector from adhering to the national procurement policies of the country's Public Procurement Authority.

b) Procurement Weaknesses

Major weaknesses, often seen in state procurement systems, contribute to delays in awarding contracts and non-compliance with rules and regulations. Vague guidelines, poor monitoring, weak institutional support, and inadequate knowledge and skills have exacerbated these delays. Due to time and cost overruns, the procurement system is often viewed as an obstacle to ensuring the timely contracting of generation capacity (Liyanaage 2005:50). Figure 2.3

provides an example of the timelines of IPP contracting from project conceptualisation until closure of the deal. As illustrated, with optimal contracting processes, it can take between 18 and 24 months for the contracting parties to reach agreement. With weak or vague contracting processes, each phase holds the potential for delay. When the authority over the electricity investment is shared by so many constituencies and government departments, regulatory systems often fail to secure public consent early enough for siting power plants (Huber 1987:1002). Agencies often operate in isolation which means that good regulatory intentions often translate to ill-timed or delayed decisions. When processes are not widely agreed on by various stakeholders in the contracting process *ex ante*, delays may be experienced during the procurement process.⁶⁴

Figure 2. 3: Timeline of an IPP Contracting Process



Source: Marlow (2008)

Even when there is surplus capacity, the long lead times before commissioning takes place make timely decisions essential. Most large power markets in the world are approaching, or are in, a major investment cycle as surplus capacity has been depleted (IEA 2003:11). This puts pressure on the supply of power generation equipment with some original equipment manufacturers' (OEM) waiting lists extending to a number of years before the required equipment can be supplied.⁶⁵ Often, procurement planning fails to anticipate delays in the global power equipment supply market thereby leading to delays in bringing on additional generation capacity (Gardner and Rogers 1999:1289). In addition, where governments have localisation requirements and not enough preparatory work has been done to accommodate

⁶⁴ In addition, the longer the time taken in contracting, the costlier it becomes (Mohlola 2007).

⁶⁵ During the years of surplus capacity, many manufacturers of equipment scaled down or closed down production facilities to focus on maintenance and consulting activities.

this in the procurement framework, delays in developing and commissioning generation plants may result.

c) Non-transparent Procurement Processes

Most power sectors in developing countries started reforms and the introduction of IPPs under a single buyer purchasing framework due to its ease of implementation and the minimal structural changes required. Although single buyer models have advantages, such as the ability to attract private capital under long-term PPAs, they also have potential pitfalls. The single buyer framework centralises many of the planning and procurement functions (in itself, a positive move), but without adequate governance or transparency; and procurement and purchasing arrangements are open to political interference, leading to corruption (Arizu, Gencer et al. 2006:10). Africa is not unfamiliar with controversies around government spending and many projects have been distressed due to inadequate and non-transparent procurement processes employed by government departments and utilities. Although there are well-known guidelines for ensuring efficient public procurement - developed by organisations such as the World Trade Organisation (WTO), the World Bank, and other multilateral organisations - many developing countries do not subject their procurement policies to multilateral surveillance or international disciplines (Hoekman 1998:249).⁶⁶ Non-transparent procurement processes allow for bribery of procurement officials and corruption which could increase project costs by as much as 50 per cent (Hoekman 1998:255).

The lack of transparency and risk of corruption are thus significant impediments to efficient and timely procurement of infrastructure.⁶⁷

⁶⁶ Reasons for this may include intent to discriminate against certain firms; unfamiliarity with the multilateral endorsed governance procurement rules; a perception that the potential benefits of adhering to these rules are small; or successful opposition from groups that benefit from current practices (Hoekman 1998:249).

⁶⁷ In Nigeria, with the development of the Enron/AES Barge IPP, competitive bidding was overlooked for a directly negotiated deal. Later, the deal came unstuck and renegotiations carried on for six months. Major objections were raised regarding the lack of transparency in procurement, the fact that the plant would not be penalised for poor performance, claims that the project company would receive excessive contract termination payments, and that these payments could bankrupt national utilities (Momodu, Gratwick et al. 2006:13). For Nigeria's second IPP, Okpai, which was also developed from a direct negotiation, investment costs rose by roughly 50 per cent between the time of initial negotiations and final commissioning of the plant. Among the reasons cited for increased costs was the underestimation of the cost for transmission infrastructure. Although the parties were seeking ways to

d) Unsolicited Proposals

In many cases electricity is procured from unsolicited IPP proposals. Proponents often cite their possession of intellectual property rights on aspects of project technology as a reason for sole source contracting. Others claim that special circumstances around the lack of private sector interest, cost efficiency due to the scale, risk profile or location, or uniqueness of projects, warrant direct contracting from an unsolicited bid. Still others assert that the shortage of power, especially during emergencies, dictates the need to speed up project development and bypass lengthy competitive procurement processes. While under certain conditions governments may justify direct negotiations on unsolicited proposals, the experiences in several countries have shown that sole-source negotiations usually take longer to reach closure than originally intended and could delay projects by several years.⁶⁸

Prices also escalate as private sponsors adjust their offering to the required specifications – this could be the case when the purchaser knows little about the technology at the start of the project or little is known about the government’s requirements by the project sponsor (Bos and Lulfesmann 1996:53-54). In Indonesia, for example, the negotiations of many unsolicited proposals spanned several years with negotiating parties not being able to reach financial closure. Negotiations for the Dabhol plant in India continued for nearly a decade when a new government cancelled the initial agreement and restructured the deal under different terms (Hodges and Dellacha 2007:4). Excessive costs and alleged corruption were cited as the main reasons for the Indian government’s cancellation of the original Dabhol IPP agreements and

settle the dispute around the increased costs, the off-taker refused to make full payments for the power produced (2006:15).

⁶⁸ The author does not advocate that all procurement should be processed through competitive bidding since this may not be in the best interests of governments or developers when projects are complex and there are few available bidders. In the case of complex projects, competitive bidding processes may stifle communication between parties involved in procurement leading to the buyer missing out on innovative opportunities to save on costs, time and effort (Bajari, McMillan et al. 2003). However, where projects use standard technology and development is, by and large, customary, tender specifications can be simplified, and, generally, more bidders will drive down price in accordance with competition theory (Bettignies and Ross 2004:148). In the main, competitively contracted generating plants have found their costs to be lower than directly negotiated plants and, irrespective of the contract terms, on the whole, competitively contracted plants were found to be less likely to attract adverse renegotiations (and delays in reaching closure) than directly negotiated plants (Woodhouse 2005c:65). Competitive bidding in IPPs is reported to have reduced PPA charges by as much as 25 per cent (Albouy and Bousba 1998:5-6).

restarting negotiations which led to a delay of 16 months at a cost of US\$175m (Sader 2000:35).⁶⁹ Unsolicited proposals which are not channelled through a transparent and competitive process often increase perceptions of corruption. Those that have led to directly negotiated deals have resulted in contracts for power projects which were not needed and, in addition to attractive terms and high prices for investors, shifted all the major risk to the buyer, the host utility government.

Hodges and Dellacha (2007:vii) advocate that, as a minimum, all unsolicited proposals should be channelled through a process where competitors can challenge each others' proposal on pre-determined criteria, such as price, with the possibility of winning the tender. A number of countries have adopted systems to establish broader sector support for projects by guiding unsolicited proposals through a process where competitors have a fair chance of winning the tender. One such system is the 'bonus system' where a bonus is awarded to the original proponent of the project when the project subsequently goes out on open tender (Hodges 2003). If, for example, the bonus allocated to the original proponent is 5 per cent, the tender will only go to this proponent if his offer is less than 5 per cent above the lowest price tendered for the project. The bonus is, therefore, a reward for the preparatory work done in the original project proposal. Another popular system for treating unsolicited proposals is the Swiss challenge which allows third parties to make counter proposals to that of the original promoter. If a third party challenger's bid is found to be more favourable, then the original promoter is given another chance to match this. The idea behind the process is to discourage opportunism and avoid exaggerated project development costs (Verma 2007). Another similar system is known as the 'best and final offer'. Here, the initial promoter does not enjoy the advantage of matching the lowest bid, since only one round of tendering is allowed.

e) Allocation of New Build Opportunities

In many cases, new build opportunities for the public and private sectors are not based on equitable and transparent criteria. While SOEs often maintain that they can build new plants cheaper than can the private sector, they often do not provide any financial bases for their claims or explain how conditional risks will be allocated. With public investment, the cost of power is frequently assessed without taking into account contingent liabilities that are saddled on governments, consumers and tax payers. In many cases, single buyers are the incumbent

⁶⁹ In retrospect, many government officials in India questioned the decision to use direct negotiation with the objective of speeding up the development of the project. The PPA terms were unbalanced in favour of investors and the host country payment obligations were viewed as exploitative by the public and not sustainable (Lamb 2006:39-40).

SOEs who can block potential private investments in generation by discriminating against them with respect to transmission access. With only one wholesale buyer, the creation of flexible off-taker agreements has proved to be difficult when SOE utilities have not allowed potential IPPs to supply power to existing customers. Rules for the dispatching of power stations are developed by SOE utilities, which are also the transmission system operators. Under single buyer arrangements, therefore, SOE utilities have a conflict of interest which concerns investors contemplating entering the market. Given the flexibility required for progressing future market development, investors have also been concerned about the certainty of their long-term PPAs (Eberhard and Kapika 2008).

In summary, delays in contracting new generation plant due to inadequate planning prolong the immediate inconvenience of insufficient capacity. Similarly, deficient procurement frameworks often lead to delays and, in an environment of non-transparency, they are subject to corruption. Prospective investors and lenders are wary of making investments in countries where such problems exist, or they add significant premiums to compensate for the increase in the perceived risks. Experiences or perceptions of corruption make it more difficult for countries to attract investment for future generation projects thereby exacerbating the challenges of dealing with shortages in generation capacity. Lastly, in many cases, purchasing arrangements have allowed state-owned utilities to frustrate investment by the private sector.

2.5 Conclusion

This chapter has contributed to the development of a useful framework for analysing emergent hybrid power markets in Africa with a specific focus on the extent to which these markets have created new challenges to attracting investment in generation capacity. The framework rests critically on the recognition of four important insights.

Firstly, power sector reform in Africa came about largely as a result of dissatisfaction among many power sector stakeholders with the functioning of national utilities and their poor performances under state ownership. Prompted mainly by development finance institutions such as the World Bank, power sector reform was initiated out of a desire to improve performance and attract sufficient resources for expansion in order to meet and sustain development goals. The standard model of reform involved unbundling, privatisation and competition. Yet, as we have shown, the standard reform model has not been fully implemented in Africa or other emerging economies. While IPPs have been introduced, incumbent SOEs have often retained their dominant market position. What has emerged in

practice is a hybrid power market which has profound implications for new investment in generation capacity. The theory and experience of power sector reform, therefore, frames the broader context for the empirical analysis in this thesis.

Secondly, the role of SOEs in hybrid power markets and in securing additional generation capacity remains seminal. Sometimes they may continue to invest directly in new generation. Alternatively, they are off-takers for IPPs. The performance of SOE utilities is thus critical. But as a result of the social and development role that electricity has played, and continues to play, power utility SOEs have become politicised and their complex relationships with governments have made it difficult to transform them. Although reforms have brought new institutional arrangements, regulatory frameworks and changes in functional responsibilities which affect SOEs, improving their performance remains a difficult challenge. These contextual factors have important explanatory power in helping to elucidate how and why the functioning of SOEs is closely linked to problems of insufficient investment.

Thirdly, sponsors of private producers of power, as the latest entrants in African hybrid markets, have investment expectations. The degree to which these expectations can be met largely determines the country's ability to attract and sustain investment through IPPs. The challenges in attracting private generation investment in evolving power sectors as outlined in this chapter serve as an additional background for understanding and analysing the problems of insufficient investment in generation capacity.⁷⁰

Lastly, the dynamics of hybrid power markets present new challenges that unless explicitly addressed will frustrate attempts to bring in new power investments. Planning functions can be neglected. Weak linkages between generation planning and procurement of power plants can result in delaying the commissioning of power stations and, thus, the provision of electricity services to consumers. Under certain conditions, contracting arrangements hold the potential to discourage investment in generation infrastructure, instead of facilitating it. The responsibilities and functions of power sector planning, procurement and contracting need to be explicitly assigned in hybrid power markets and sufficient capacity needs to be developed to undertake these effectively.

⁷⁰ This thesis does not consider investment theories or theory on FDI but, rather, jumps straight to the issues that are immediately related to generation investments in reforming power sectors in Africa where investment conditions are generally less than favourable.

The analytical framework developed through this chapter is relevant for examining challenges in attracting investment in generation and addressing the research questions posed in Chapter 1. This analytical framework will be revisited again in Chapter 7 in considering how the analysis of the data in the empirical chapters provides new insights and might enable further extension of these frameworks and a deeper understanding of how future reforms may be directed to increase investment in generation in hybrid electricity markets in developing countries.

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CHAPTER 3

POWER SECTOR REFORM IN GHANA

In the case of Ghana, the ambition of transforming the ESI according to the standard reform model has not been realised and in the absence of a competitive market arrangement, the institutional and governance frameworks have proved to be inadequate for the single buyer arrangement in the hybrid model that has since emerged. More than a decade after power sector reforms were instituted in Ghana, the country has been unable to transform its power sector to deal with challenges of insufficient generation capacity and power blackouts. Reforms prompted the establishment of new institutions to usher in a new era of power sector development; and various functions in the power sector were re-assigned to institutions in accordance with the reform agenda. One such function was that of planning, originally vested with the state-owned utility. As part of the reorganisation process, this function was transferred to a new agency responsible for long-term planning. While the agency took responsibility for indicative planning, it did not take responsibility for detailed planning or for the procurement and contracting functions previously performed by the state-owned utility.

Inadequate procurement frameworks contributed to the problems of insufficient capacity since processes for procurement and contracting have been vague. Where attempts were made to improve procurement policies, these processes were not always adhered to, even in cases where the state administered the process. Regulatory and governance frameworks have been ill equipped to provide adequate oversight with respect to generation planning and procurement, and therefore unable to guide the power sector towards its reform objectives. Although the Ministry of Energy has attempted to facilitate the development of additional capacity, inconsistencies in the application of the country's stated preferred procurement process have resulted in project delays and cancellations. Political interference and the government's reneging on its previous commitments to the sector, especially with regard to tariff setting, have also contributed to a lack of credibility in the processes and institutions in the ESI. In addition, Not only have regulatory institutions been undermined in the execution of their tasks, but institutional coordination aimed at facilitating investment in generation and respond to the challenges of capacity shortages in the hybrid market, has been lacking.

3.1 Introduction

Power sector reforms in Ghana formed part of a larger Structural Adjustment Programme, which was prompted by the World Bank and the IMF, to stabilise the Ghanaian economy. In return for financial aid to put the country on the road to recovery, Ghana agreed to institute a series of Structural Adjustment Programmes with the objectives of adopting market-driven policies and reducing the role of government in the economy. With power production playing a central part in the economy, as was the case with many developing countries, the Ghanaian electricity industry and its associated institutions were included in the portfolio of economic sectors that were due for reform and private investment. With insufficient public finance to fund generation capacity expansions, private sector participation was seen as crucial.

This chapter describes and assesses Ghana's experience of attracting generation investment into its ESI. It evaluates, in detail, the development of the only large-scale greenfield independent power project (IPP) operational in Ghana by 2008. It also briefly describes other generation projects that have been planned and negotiated but never came to fruition. By evaluating these projects, this chapter helps to show how various issues in the power sector aggregated to create conditions that were not conducive for new power generation investments.

The chapter is structured into five main parts. Immediately following this brief introduction, the next section provides a description of the power sector in Ghana. The third section describes sector reforms that were planned and implemented. The fourth section describes the development of Takoradi II, the country's first large scale IPP. Finally, the last section discusses some of the key elements that frustrated investment into new generation capacity.

The information presented in this chapter draws mainly on detailed interviews with key stakeholders during a country visit in 2007. Interviews were subsequently followed by email correspondence to clarify discussion points in 2007 and 2008. Stakeholder interviews included representatives from the Ministry of Mines and Energy, Volta River Authority, Energy Company of Ghana, Ghana Energy Foundation, Consumer Michigan Services (CMS), the Energy Commission, the Public Utilities Regulatory Commission, the World Bank, as well as a number of unaffiliated industry professionals from non-governmental organisations and academia. Throughout the text, stakeholders have not been identified by name but by organizational affiliation.

3.2 The Ghanaian Power Sector: Past and Present

This section gives a brief description of the ESI in Ghana and the institutional context which sets the background for power sector reform and the introduction of IPPs.

3.2.1 Generation

As early as 1915, the Volta River was identified as a resource to produce hydroelectricity, which would, in turn, help spur industrialisation. Development of the resource was made more likely with the discovery of bauxite and the potential for aluminium production which requires large amounts of cheap electricity. Further studies in the 1950s reported favourably on the prospects of the hydro generation facility and an aluminium industry. It would, however, take another decade before work on the Volta River would commence.

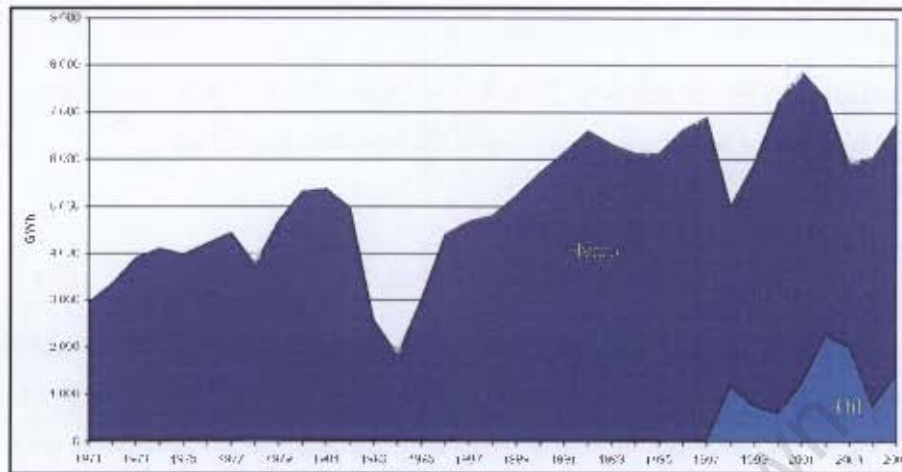
The Volta River Authority (VRA) was established following the Volta River Development Act (Act 46 of the Republic of Ghana) in 1961 (VRA 2006). Work began soon thereafter on the Volta River dam and the VRA's first hydroelectric station at Akosombo was commissioned in 1965, with two generators totalling 294MW. Two more units were completed in 1966 to bring the total capacity to 588MW. By 1972 two additional units with a combined capacity of 324MW were commissioned to bring the total capacity of Akosombo to 912MW. This was later upgraded to 1020MW. The Kpong hydroelectric project followed in 1982, adding another 160MW (VRA 2006).⁷¹

In 1983 and 1984, drought caused dam levels to decrease to a point where daily load-shedding throughout the country was inevitable. The unexpected drought brought the sober realisation of the country's overdependence on hydro. The government then took a strategic decision to complement hydro with thermal power, thereby mitigating supply risks against the effects of low rainfall. The decision led to the development by the VRA of the Takoradi thermal power plant in 1997. Although the 330 MW combined cycle plant was designed for use with light crude oil, longer terms plans envisaged the use of natural gas once the West African Gas Pipeline (WAGP) from Nigeria was developed.⁷²

⁷¹ In 2003 and 2004, the VRA completed a retrofit programme on the Akosombo turbines bringing the total hydro capacity to 1180MW.

⁷² The West African Gas Pipeline is designed to transport Nigerian gas (which has traditionally been flared) to other coastal West-African countries. Ghana, through the VRA, has a 16.3 per cent share in

Figure 3. 1: Electricity Production from Hydro and Thermal Sources in Ghana



Source: OECD/IEA (2007a)

Again, in 1998, low rainfall impacted the country, when the Akosombo dam level fell to 237.5 feet compared to a minimum operating level of 240 feet. Frequent load-shedding ensued. Many bulk consumers, such as mines as well as other export industries, were load-shed on a rotational basis and certain regions were rationed with only 12 hours of electricity supply per day. As illustrated in Figure 3.1, the effects of the drought were not as significant as that of 1983 and were, in part, cushioned by Takoradi I and capacity from the emergency diesel operated generator sets procured by the Ministry of Mines and Energy, which came on line at the time. The lack of rain was not, however, the only explanation for the 1998 power shortages. Van Edig (2000) suggests that low tariffs administered by the government resulted in inadequate resources to fund additional long-term investment and that this was a key underlying reason for the daily load-shedding.

In 2000, the country's first IPP, Takoradi International Company (TICO), also referred to as Takoradi II, came online, further bolstering the country's generation potential. While the design made provision for a combined cycle plant, it was constructed initially as a simple cycle 220MW plant.

In 2006 and 2007, Ghana found itself in the midst of another power crisis, partly due to reduced hydro generation, lack of investment, and a significant increase in electricity demand.

the West African Gas Pipeline (WAGP). Other partners are Chevron Texaco (36.7 per cent), the Nigerian National Petroleum Corporation (25 per cent), Shell (18 per cent), SoBeGaz (2 per cent) and SoToGaz (2 per cent) (EIA 2003).

which has been driven by buoyant economic growth.⁷³ Thus, despite the thermal complementation, hydro still remains dominant in Ghana's capacity mix, as depicted in Table 3.1 below.

Table 3.1: Ghana Installed Power Generation Capacity (2008)

Plant	Type	Owner	Installed MW
Akosombo	Hydro	VRA	1020
Kpong	Hydro	VRA	160
Tema ⁷⁴	Thermal	VRA	30
Takoradi I	Thermal	VRA	330
Takoradi II	Thermal	CMS ⁷⁵ 90%, VRA 10%	220

3.2.2 Revived and Stillborn Plants

It is important to note that a number of other privately financed power projects, mostly (but not exclusively) thermal generation plants, have been considered over the last decade, but none had come to fruition. Brief descriptions of these projects are presented below.

a) Bui

The Bui hydro project was initiated as far back as 1966 when a Russian consortium working on the development was forced to leave Ghana as a result of the coup in 1966 that ousted the country's first president after Ghana's independence. The project was reappraised several times in the three decades that followed, but it was the recent power crises that spurred on the Government of Ghana to once again pursue it with a greater sense of urgency. In 2005, the Government of Ghana signed a memorandum of understanding with Sino Hydro, a Chinese construction company, to undertake the construction of the Bui dam at a cost of US\$500m. This 400MW plant is now fully back on the agenda and construction started by the end of 2007 (The Statesman 2007) with completion scheduled for 2012 (Adda 2007).

⁷³ Power cuts to mitigate the imbalance between supply and demand started in August 2006 and continued for about one year.

⁷⁴ The VRA has a 30MW diesel station in Tema. The Tema plant was installed between 1961 and 1963, and ran continuously until 1966. Thereafter, it was used on standby until 1979. The station has been operated as a contingency plant since then (Energy Commission 2005).

⁷⁵ CMS sold its share in Takoradi II to the Abu Dhabi National Energy Company (TAQA) in 2007.

b) Osagyefo / Western Power

Another project that has been resurrected is the Osagyefo barge or Mangyea Project, better known as the Western Power IPP - two units, supplied by Ansaldo Energia of Italy, with a combined capacity of 138MW. This IPP was planned by the Ghana National Petroleum Company (GNPC). Mainly charged with the management of petroleum imports and exploration, the GNPC embarked on plans to generate power as an IPP (Turkson and Amadu 1999:25). The CEO was well connected to the erstwhile president and as a result had considerable leeway in the management of the company. The corporation soon branched out into other business areas such as salt and mining (KNUST pers. com. 2007). It then turned to power generation and kick-started the Western Power Project when off-shore gas was found in the western part of Ghana. The Japan Bank for International Cooperation agreed to finance the barge but the project stalled when assurances could not be obtained for the development of the gas infrastructure to exploit the gas fields.⁷⁶ With the inauguration of a new president in 2000 and the subsequent selling off of ailing state-owned enterprises, many subsidiaries of the Ghana National Petroleum Company were closed down (including the Western Power Project). Relocation of the plant on-shore to Tema in order to use gas from the WAGP when this becomes available was considered, but the idea was shelved and the government went back to the original plan to install the plant at Effasu (where there is still no gas infrastructure available) (Energy Commission pers. com. 2007). In July 2007 the Government of Ghana signed a PPA with Balkan Energy of the US to make the barge operational and run it on diesel until gas becomes available (Ministry of Energy 2007).⁷⁷

c) SIIF Accra

Yet another project that did not come to fruition was that of the SIIF Ghana, an 80 MW thermal plant negotiated during the drought of 1998 (Heath Lambert Group 2002). By the

⁷⁶ It was calculated that the life span of the Tano oil fields (15 years), which was to fire the barge, was too short to make the initiative viable. The transmission lines that would have transmitted the power from the barge had however been constructed, including two large substations. Available information indicates that when the barge arrived in Ghana, the access to the pond was not large enough for the barge to be towed. Although an inter-ministerial committee was set up to investigate other possible sources of fuel to operate the plant, the final verdict was that the preferred fuel would not be available at the right price and within the given timeframes to operate the plant, and that diesel would be the only alternative (The Chronicle 2005; Ministry of Energy 2007).

⁷⁷ The first phase of the barge was reportedly completed and operational by the last quarter of 2008 (Reuters 2008). The second phase, scheduled to start in 2009, was the expansion of the existing 125 MW simple cycle plant to a combined cycle plant (Balkan Energy 2008).

time that the project agreements between the developers and the Ghanaian government were signed, dam levels had stabilised, but were still considered low. Construction of the plant was well underway when weather conditions improved and dam levels recovered. When the government announced that it would no longer buy the power as agreed, a dispute was declared and the case went for international arbitration. The plant was eventually removed and sold to Togo.

d) AES Sirocco

AES Sirocco Limited sought to develop a 300MW thermal IPP in Tema. The VRA would be the off-taker and have a small shareholding in the project. The project was indefinitely stalled when a bill was tabled in Parliament with the intention of prohibiting the VRA from acquiring equity stakes in any more thermal projects.⁷⁸ In addition, AES took on a much more cautious approach to financing new power plant investments following the collapse of Enron and the subsequent financial difficulties experienced in the international power trading industry in 2001 and 2002 (ECA, 2003).

e) Ashanti/KMR

In 1998, Ashanti Goldfields also promoted the development of a 300MW thermal plant with KMR.⁷⁹ Serving Ashanti's mines as well as a few other mines would be the primary purpose of the plant. The remaining capacity, which could reach up to 50 per cent depending on the mines' load profiles, would then be available for other customers or sold to the grid. In addition to the provision of a 15-year PPA, Ashanti would have carried the risk of selling power onto other mines. KMR which would take on 80 per cent of the project equity (Ashanti would retain the remaining 20 per cent) was reportedly keen to proceed with the project on a 15 per cent rate of return. Ashanti which hoped to achieve an electricity tariff of 4c/kWh once gas from the West African Gas Pipeline became available, needed to achieve this rate inclusive of transmission charges, but at the time the VRA demanded 1.5c/kWh for transmitting the power. The VRA justified these charges through a revaluation methodology of their assets which Ashanti disputed, mainly on the treatment of inflation in this new methodology. When Ashanti was told that they would not be permitted to sell to any existing VRA customers and that the proposed buy-back rate would be 2c/kWh for the surplus energy of the project, the project was halted. Although they examined the options of developing the

⁷⁸ After much debate, the proposed bill was eventually scrapped.

⁷⁹ KMR was bought out by AES in 2001.

plant in - and importing from - Côte d'Ivoire or locating the plant in neighbouring Benin, Ashanti still faced the bane of wheeling charges from the VRA (ECA, 2003).

f) Aggreko and Cummins

Two other plants were also negotiated through a rental system to plug the immediate power shortages during the drought of 1998. They were those of Aggreko which entered into an 18-month contract with the Government of Ghana to supply 30MW at Tema, and Cummins which entered into a similar 24-month contract with the government. While Aggreko did supply power, it was only after the power crisis that Cummins Power Generation was fully operational. Already having signed the PPA, and despite no longer needing the power, the government was invoiced for the power in accordance with the take-or-pay agreement. By mid-2007, eight years after the drought, a legal battle was still pending in London with the Government of Ghana to settle a mounting debt of approximately US\$20m to Cummins which was signed under the previous regime. The former Minister of Mines and Energy, Joseph Kofi Adda, in his speech to parliament in June 2007 also mentioned three additional power companies who had contracted with the government for private power production and later sued for damages despite not having generated any power; Global Aero Design Company, Stone and Webster and Faroe Atlantic Company. In the case of Faroe Atlantic Company from the UK, the Ghanaian government entered into a PPA with the firm to provide additional capacity. Although the Ministry of Finance represented the Ghanaian government in the deal, internal parliamentary approval had not been sought by the Ministry of Finance, despite this being a requirement for such large-scale projects. On Faroe's court action, the High Court first ruled in Faroe's favour the sum of US\$6.3m plus interest. The government then appealed, but the case was dismissed by the Appeals Court leaving the government with the bill for damages. But when the government appealed to the Supreme Court on the basis of the legality of the transaction, the Supreme Court ruled in favour of the government based on its obligation to uphold the constitution (and the laws of the country). The Supreme Court ruled that the agreement was unenforceable due to lack of mandatory parliamentary approval and concluded that the absence of parliamentary approval rendered the contract null and void (Oxford and Beaumont 2006).

In summary, a number of plants have been planned and negotiated over the years; while some have been developed to completion without generating electricity onto the grid, others are again on the agenda and in the development stages despite these projects having been initiated a long time ago.

3.2.3 Future Plants

Looking forward towards 2020, Ghana's Strategic National Energy Plan (2006) estimates that the country will need an additional 2000 MW of generation capacity, based on a moderate economic growth projection. This demand projection increases to well over 2500 MW of additional capacity for a high economic growth scenario (Energy Commission 2005:8). It is almost certain that private participation in the power sector will continue, in line with government and World Bank policy. The need for a favourable investment climate to attract and facilitate private power procurement should not be understated and will remain a challenge for the country at least in the medium term.

According to the Ministry of Energy, as per Ghana's Strategic National Energy Plan (2006), plans are also in place to convert Takoradi II to a combined cycle plant in 2009 (African Energy 2007). As it currently stands, the plant would have to be taken out of service to complete the steam phase. With the current power crisis, more capacity would first have to come on line to avoid large scale blackouts. However, an EPC request that was put on tender expired without stakeholders reaching agreement on the terms (CMS pers.com. 2007).⁸⁰ Despite an EPC which was subject to an open tender bid, the government still believed that the charges asked from CMS were too high and the security arrangements demanded were too stringent. In 2003 it was estimated that the additional steam cycle would cost a further US\$140m (ECA 2003). By 2007 the steam cycle phase was estimated at US\$215m for an additional 110MW (Adda 2007). In spite of costs having inflated over the years, the additional efficiency and the debt financing would still result in lower electricity tariffs.

Apart from Ghana's existing thermal plants, much has been riding on the expectation of the long awaited WAGP from Nigeria in terms of future capacity expansions. According to the Ministry of Energy, there are a number of independent power projects in the pipeline. Of the remaining half dozen projects that are planned for development, the soonest to come on line may be the Kpone IPP, a project company made up of a consortium of local and international partners (CenPower, and Infracore and Reltub). The 400MW, gas fired, combined cycle power plant will be located in the municipality of Kpone within the Tema industrial zone and will become one of the main off-takers of the WAGP (Evans, 2007). With a construction time of two years the US\$300m project, which is designed for at least 25 years of operation, is

⁸⁰ The EPC bid process favoured Black and Veatch.

scheduled to commence commercial operations in 2009, depending on progress with the gas pipeline (CenPower pers. com. 2007; InfraCo 2007).

An IPP company had also been registered to develop the Osonor Thermal Plant late in 2007. This development was planned to be a joint venture between the VRA and Tema Osonor Plant Limited (TOPL). The VRA would install a combustion turbine to generate electricity. Together with the combustion turbine of TOPL, the overall strategic plan was to develop a combined steam cycle using the exhaust gases from the two plants which are planned to be located on the same site (AfDB 2007).

In april 2008, sunon asogli power limited (ghana) was founded by a chinese company, shenzhen energy investments co. Ltd, and the china-africa development fund, to develop a combined cycle power plant in the tema region (China Daily 2008). The plant was expected to have an installed capacity of 560mw and construction was scheduled to start late in 2008.

Although there are a number of plants in the pipeline, past experience has shown that ghana has a history of negotiating and even developing some plants that do not come to fruition. The number of negotiations ongoing suggests that ghana aims to maximise their chances of securing investment. This approach, however, risks having inadequate focus and insufficient deliberation on individual projects by sector stakeholders within a broader capacity expansion context. It may be more beneficial to focus on only one or two projects and, in so doing, maximise the chances of project success. Also while some sponsors are negotiating with the vra, others are in talks with the electricity corporation of ghana (ecg), and still others are consulting directly with the ministry of energy. The silo effect risks a lack of coherence in implementing sound strategies in procuring generation. At this stage, the official process to procure generation within ghana is unclear with a number of informal processes available for prospective project sponsors (World Bank pers. com. 2007).

3.2.4 Transmission and Distribution

At the time of Ghana's independence in 1957 the public sector, through the Electricity Department operating under the Minister of Public Works, assumed responsibility for electricity generation, transmission and distribution. In 1967, the Electricity Corporation of Ghana (ECG) was established to replace the Electricity Department. The ECG was charged with the procurement of bulk electricity and its distribution to all consumers throughout the country.

Over the years, however, the ECG became weighed down with substandard service levels, poor financial performance, labour disputes, and disruptions at a senior level in the organisation. Eventually, the government decided that the ECG should focus on resolving its organizational problems and that the VRA should take over the distribution of electricity in the four northern regions. Through its subsidiary, the Northern Electricity Department (NED), established in 1987, the VRA assumed responsibility for power distribution in Brong-Ahafo, Northern, Upper East and Upper West regions. In southern Ghana, viz. Ashanti, Central, Greater Accra, Eastern and Volta regions, the ECG remains responsible for the distribution of electricity to consumers.⁸¹ Substantial progress has been achieved in electrification over the years and access rates approached 50 per cent in 2007.

To enable power exchange to neighbouring Togo and Benin, a transmission link was completed in December 1972 (VRA 2006). A transmission link with Côte d'Ivoire was also established in 1984. Power flow was initially from Ghana to Côte d'Ivoire, but following Ghana's power crises in the 1990s, trade flows have been reversed.

3.2.5 Demand-Side Management

After the country's electrification programme increased demand for electricity, the government introduced a number of energy efficiency and conservation initiatives.⁸² These

⁸¹ The four regions were among the main areas earmarked for rural electrification and called for significant extension of the power distribution grid. At the time, the VRA, , was in a relatively favourable financial position and it was therefore advantageous to offer the management of the electricity distribution in the four regions to the VRA in order to secure the required loans for that portion of the rural electrification project (EFG pers. com. 2007).

⁸² In Ghana, the growing customer base can be attributed, in part, to the National Electrification Scheme (NES). Instituted in 1989, the scheme is the Government of Ghana's primary policy instrument to electrify the country over a thirty-year period, from 1990 to 2020. At the time the scheme was instituted, only 15% of the total population had access to electricity supply. For the rural population who account for more than 70% of the population, access to electricity was as low as 5%. In addition to poverty reduction by increasing the socio-economic development of the Ghanaians, the NES aims to facilitate the promotion of small-to-medium scale industries in rural areas while creating employment in the rural areas and reducing the rate of rural to urban migration. Largely financed by the World Bank and other bilateral funding agencies, the NES had connected about 3000 towns and villages to the national grid by September 2005. In accordance with the 2000 population census, electricity access increased from 15% in 1989 to 43% in 2000. In 2006, Ghana's National Energy Policy document estimated national electricity access at 48% with 77% of urban households having access to electricity

were conceived by the Ministry of Mines and Energy and the Chamber of Mines⁸³, executed by the Energy Foundation of Ghana (EFG), and focussed mainly on provision of technical support to industries, introduction of compact fluorescent lamps (CFLs) and public education. The EFG have advocated implementing time-of-use tariffs to change consumption behaviour but acknowledge that metering requirements would pose the single biggest challenge (EFG pers. com. 2007).

Frustration is perceived on the part of the EFG at the slow response (or lack thereof) of decision makers when it comes to fund allocations for projects that provide benefits in terms of energy efficiency and return on investment. A proposal that was sent to the Ministry of Finance in 2003 to install 5-million CFL in Ghana had received no response by 2007 despite a number of follow-up requests during the four years. Through this initiative alone, it was envisaged that 180MW could be saved during peak-load periods. A bankable energy-saving pilot project was also proposed to refit military barracks with more energy efficient devices, but again this was not realised due to delays in the Ministries of Energy and Finance (EFG pers. com. 2007).

The relatively low tariffs have also meant that incentives for energy efficiency have not been as attractive as they would have been if tariffs had reflected the LRMC of generation. As a result, they have not encouraged energy efficiency on the scale envisaged.

In sum, Ghana's ESI is characterised by a generation mix that is still largely dependent on hydro power. Recurring drought coupled with the pressure to extend electricity access to more Ghanaians has led to a greater focus on developing thermal generation capacity and importing more power from neighbouring Côte d'Ivoire leading to greater energy dependence. Power shortages remain a major threat in Ghana.

compared to only 17% of households in rural areas (Ministry of Energy 2006). Even though all the ten regional capitals and 130 districts are connected to the national grid, there is regional disparity in access with the southern part of the country having higher access than the northern part.

⁸³ The benefits of the Foundation's energy efficiency initiatives include lower consumption due to power factor corrections at a number of factories in Ghana.

3.3 Power Sector Reforms

A review of the electricity supply industry in Ghana suggests that there have been many factors that have shaped the pace, as well as institutional aspects, of reform in the sector. One such factor is the role that the World Bank has historically played, and will most likely continue to play, in the sector. The World Bank has extended loans to the VRA from the time of its inception. Generally, these loans have been linked to the country's economic recovery programme and were tied to conditions, which included power sector reform and the introduction of private capital to assist in infrastructure expansion.

3.3.1 Reform Influences and Actions

A significant factor prompting reform of the sector was the severe droughts, mentioned previously in section 3.2.1, that affected the country between 1982 and 1983 and again in the 1990s. Coupled with sharp annual increases in electricity demand of between 10-15 per cent from 1982 to 1995, the need for transformation in the sector was brought into the spotlight (Edjekumhene and Navroz 2002). The second drought from 1993 to 1995, coupled with growing demand, intensified the need for complementing hydro with thermal power.

At the time of negotiations between the Government of Ghana and the World Bank over a loan for the development of VRA's first bulk thermal plant, the bank's International Development Association (IDA) laid down conditions for sector reform. Although the bank was content to see the VRA remain a dominant generator, it expressed a desire to supplement generation capacity with independent power producers. The bank approved the loan on the proviso that the Power Sector Reform Committee (PSRC) would be established to deliberate the operational, legal and commercial implications of the reform agenda.

Although the World Bank expressed its desire to see reforms in the sector, the changes that it had envisioned were limited. It therefore came as a surprise to the bank when the government replied with a comprehensive policy framework that was much more extensive than the bank had prescribed. Contracting in a Chilean firm, SYNEX Consulting Engineers, as consultants, the PSRC submitted their recommendations to the Government of Ghana in a report detailing how generation, transmission and distribution sectors should be transformed. Transmission would be unbundled from the VRA to form a state-owned grid company, allowing open and non-discriminatory access to both generators and large wholesale users. On the generation side, although the PSRC had no desire to see a reorganisation in the hydropower business of

the VRA, it did recommend relying on private public partnerships to augment capacity while allowing generators to sell power directly to large consumers in a wholesale market, in addition to distributors through a grid company. Five regional distributors were proposed to supply power to consumers with consumption of less than 5MW. Consumers using more than 5MW would be eligible to participate in the wholesale power market. The NED would be unbundled from the VRA and, along with the ECG, be transformed into the five distributors, with private concessions for these distributors envisaged at a later date.⁸⁴

The PSRC also recommended instituting an independent regulatory body responsible for the issuing of licences and tariff setting. The cabinet accepted the recommendations of the PSRC and in 1997, through Act 538, the Public Utilities Regulatory Commission (PURC) was created with the authority to set tariffs. This was followed by Act 541 which led to the establishment of the Energy Commission, an advisory body to the ministry with the mandate of licensing and development of rules for the technical operation of the sector.⁸⁵

Although the VRA agreed in principle with the need to reform, senior officials in the organisation severely criticised the scope of the reforms proposed, arguing that the unbundling of the VRA would weaken the sector and that the model proposed, which resembles the Chilean electricity market, would not yield similar results due to the small size of the sector in Ghana (Edjekumhene, Amadu et al. 2002).

Despite the bold initial reform agenda, few developments have taken place. The generation and distribution sub-sectors remain dominated by the SOEs, VRA and ECG, and have not been unbundled, and while a regulator has been established and one IPP investment has been made, up until 2008, no new large-scale plant had been commissioned.

⁸⁴ The distribution sector has long been a focus of reform, although efforts to improve operations at the ECG have met with limited success. In addition to a management contract with the Electricity Supply Board (ESB) of Ireland in the early 1990s to revamp the organizational structure of the utility, in 1994 the ECG also contracted Electricité de France (EDF) and Société d'Amenagement Urbain et Rural (SAUR-Bouygues) to help improve the performance of its customer service and collections divisions over a four year period (World Bank 1995). Although short-term improvements were achieved, they were not sustained.

⁸⁵ The Energy Commission was modelled on the erstwhile National Energy Board, which had a strong policy advisory role and was seen as a specialised, quasi-independent 'department' in the Ministry of Energy.

3.3.2 Tariffs

Although the VRA was pessimistic about the sweeping reforms, it did welcome the establishment of the PURC, with its mandate to:

“build a credible regulatory regime that will respond adequately to stakeholder concerns and ensure fairness, transparency, reliability and equity in the provision of utility services” (PURC 1997).

Since tariff setting had been a controversial issue in the sector for a long time, it was hoped that the commission’s independence would bring greater credibility to the tariff setting process. Historically, the government has been reluctant, for political reasons, to raise tariffs to economic levels and remove subsidies. In 1997, prior to the establishment of PURC, the government had attempted to raise tariffs by 300 per cent⁸⁶, but the public outcry resulted in a presidential intervention to abate the fears of the general public and stop the tariff increase. The crisis fast tracked the establishment of the PURC in that year (initially only scheduled to be instituted in the following year). Surprisingly, this body managed to pass through a series of staggered increases cumulatively totalling a 300 per cent increase in 1998 through the establishment of a transitional plan for tariff increases (Edjekumhene and Navroz 2002).⁸⁷

Mindful of the link between electricity tariffs and the socio-economic climate in Ghana as well as its mandate and responsibility toward suppliers and their sponsors, the electricity regulator has sought a middle path in setting tariff levels. The PURC defends its low tariff increases, saying that the VRA should look internally to make efficiency gains and reduce losses, as opposed to looking solely for their rate of return in the tariff. It is expected that upon completion of the WAGP, which has experienced considerable delays, electricity production costs will drop significantly since most of the expenditure associated with thermal power production is attributed to fuel costs.

⁸⁶ Raising tariffs to a level whereby at least costs are recovered was one of the World Bank’s IDA lending conditions.

⁸⁷ The reason for the wider acceptance of the increases was due to the prolonged drought of 1997, which came as a realisation to the public that these increases were in fact necessary to ensure sustainability in the long run. The increases were approved in tandem with a comprehensive communication programme to consumers (Edjekumhene and Navroz 2002). It should be noted that inflation, largely fuelled by devaluation in currency, gnawed away at the benefits of tariff increases.

In the meantime, however, tariffs will probably continue to remain a contentious issue, as the VRA wants to see them closer to the LRMC and consumers want 'affordable' rates. The government has intervened on more than one occasion by partially absorbing tariff increases to consumers by subventions to various categories of users. At times, these subsidies have been slow in making their way back to the VRA, often hampering its ability to make timely payments, including purchases from Cote d'Ivoire and Takoradi II, the IPP.

In September 2006, government froze residential tariff increases but allowed increases to industry to continue. In August 2007, it appeared that the state would make the sector more sustainable when the chairman of the PURC disclosed that the government intended to increase tariffs and remove subsidies by the end of that year to facilitate entry of private sector participants and make tariffs more cost-reflective (Gongo News 2007). It came as a shock to the PURC Chairman, therefore, after it had announced a 35 per cent tariff increase in November 2007, when the government subsequently announced that it was increasing the lifeline tariff band to consumers threefold (from 0-50 kWh to 0-150 kWh), effectively neutralising the effect of the tariff increase. The review by government of the structure of electricity tariffs resulted in an outcry from the regulator and played a major part in the resignation of the PURC Chairman, the government's announcement being considered the last straw (Ghana Districts 2007).

a) The Volta Aluminium Company

The agreement between the VRA and the Volta Aluminium Company (VALCO) since the start of the Akosombo dam project was another reason why VRA revenues were low. The establishment of VALCO was the *raison d'être* of the VRA and this, together with the construction of the Akosombo hydroelectric station, were the two key components of the Volta River Project.⁸⁸ The historic relationship between the two organisations indicated a strong co-dependence especially during the early years while residential demand was low and VALCO consumed the bulk of the VRA's supply.

In 1968, more than three quarters of the power generated by the VRA was consumed by VALCO (Brew-Hammond 1997). The VRA, earning its revenues from VALCO in hard currency, was largely insulated from the country's fiscal turmoil and eroding currency, the

⁸⁸ At the time of the development of the Volta River Project, VALCO was 90 per cent owned by Kaiser Aluminium and Chemical Corporation and 10 per cent by Reynolds Metals.

effects of which were felt by the rest of the Ghanaian economy.⁸⁹ It was primarily due to the foreign currency earned from VALCO that the VRA could historically maintain its operational capacity and, to an extent, the capacity of the sector. By 1995, electricity generation supplied to VALCO dropped to below 40 per cent as domestic demand for power increased. By that time Ghana, which had traditionally been an exporter of power to its neighbours, became an importer of electricity from Côte d'Ivoire as its energy demand increased, as noted in section 3.2.2 (World Bank 1995c). The increasing electricity demand driven by economic expansion and, coupled with tariff structures which were based on the relatively cheap and amortised hydroelectricity, did not reflect the marginal cost of new power. The low tariffs did not help in sending the right price signals to consumers to manage the growth in electricity demand and encourage energy efficient behaviour.

During the drought years, supply to VALCO was significantly cut. In 1994, a dispute over power cuts and the VRA contractual obligation to supply VALCO eventually led to an out-of-court settlement between VALCO and the VRA. What was clear to the Government of Ghana and to the VRA was that the tariff paid by VALCO was not sustainable since VALCO was paying very much less for its power than other consumers in Ghana. In 2001, Kaiser Aluminum, VALCO's parent company, experienced financial difficulties and filed for bankruptcy.⁹⁰ Disputes related to the tariff that VALCO was entitled to in terms of the agreement signed in the 1960s continued. The government's position was that the preferential power purchase contract that was entered into with VALCO was for 30 years and expired in 1997, and that considering the significantly altered conditions of the sector, VALCO should be charged at a rate commensurate with that of other large bulk consumers, who were paying two to three times the rate of VALCO. The VRA bulk electricity tariff to VALCO until 2003 was 1.65-1.80 US cents per kWh whilst the approved bulk supply tariff to other customers was about 4.5 cents per kWh (Energy Commission 2005).⁹¹ This invariably led to the

⁸⁹ Between 1988 and 1992, foreign exchange revenues accounted for more than 75 per cent of total VRA revenues (accounting for nearly 10 per cent of Ghana's foreign exchange earnings), dropping to 40 per cent in 1995 (Brew-Hammond 1997:5.10). Electricity was Ghana's fourth largest foreign exchange earner after gold, cocoa, and timber.

⁹⁰ Reasons for this action, as cited by Kramer (2003), include a slump in the global aluminium market, costly asbestos litigation lawsuits, rising obligatory retirement pension payments and costly medical obligations.

⁹¹ At that time in 2003, the generation mix had swung to 65 per cent thermal and 35 per cent hydro as opposed to virtually all hydropower in 1967 when the power purchase contract was signed (Government of Ghana 2003).

subsidization of VALCO by US\$40-60m in 2002 (ibid). In October 2004, after lengthy disputes, the Ghanaian government decided to buy out the shares of VALCO and assume ownership of the company.

Gradually the power demand and supply situation grew worse until there was hardly any power left in the system to supply VALCO without inducing large scale blackouts throughout the country. In March 2007, the government shut down VALCO completely. The sector had lost its single largest consumer, and, with a diminishing contribution of hydro to the generation mix, was left with costly obligations to buy thermal power.

3.4 Private Sector Participation in Generation

During the drought of 1993-1994, Ghana planned to install thermal capacity to mitigate the risks of dependence on variable hydropower, as mentioned in section 3.2.1. A plan was passed to develop a thermal plant in the western region of Ghana near Sekondi-Takoradi, the country's third largest city and industrial and commercial center.

The VRA was poised to be the champion of the project on the basis of its past success and involvement in the sector.⁹² The project consisted of the construction of 330 MW of combined-cycle generation capacity, made up of two combustion light crude oil fired turbine generator sets of 110 MW each, a heat recovery boiler, a steam turbine driven generator to produce an additional 110 MW of generation, and the associated transmission and sub-station infrastructure. Construction of Takoradi I commenced in 1996 and the first simple cycle unit (110 MW combustion turbine) became operational in December 1997. The commercial operation of the second simple cycle unit began in January 1998 and commissioning activities on the combined cycle, including the steam turbine and generator, commenced in April 1999 (Jacobs-Gibb 2001). The World Bank issued an IDA loan and was the principal lender to the project on the condition that the next investment into the generation sector would be that of a private investor. The publicly funded Takoradi I (330MW combined cycle gas plant) was considered the first of a two-phase project, with Takoradi II (a 330 MW extension) expected to be privately financed.

⁹² In its 1995 Staff Appraisal Report the World Bank described the VRA as 'a relatively well-run public utility with few institutional and financial problems'.

3.4.1 The Takoradi International Company (TICO)

In an effort to raise investor interest in Takoradi II, the former President of Ghana, during a trip to the U.S. State of Michigan, engaged Consumer Michigan Services (CMS) in discussions. At the time, CMS had no investment experience in Ghana; however, it was involved in IPP deals in India and North Africa (including Morocco's Jorf Lasfar IPP). An international competitive bid (ICB) was passed over for a negotiated deal, with reasons cited that an ICB would have taken too long. Given the urgent need for power, time was of the essence (CMS pers.com. 2007; Energy Commission pers. com. 2007; PURC pers. com. 2007).

Although the initial plan was for CMS and the VRA to have an equal shareholding in the private company, at that time shortly after the drought, the financial situation of the VRA did not lend itself to such a major investment. The lower sales due to the drought and the higher cost of thermal production had strained the financial reserves of the utility. It was agreed, therefore, that CMS would take a 90 per cent stake in the project and that the VRA share would be reduced to 10 per cent with the option of increasing it to 50 per cent should the VRA's financial situation improve. It was also agreed that the first phase of the project, i.e. the two single cycle gas turbines, should be undertaken initially although the debt financing had not been finalised for the second phase of the project which comprised the steam cycle and its associated components.

Shortly after project closure at the end of 1998, the Takoradi International Company (TICO) was registered as the Special Purpose Vehicle (SPV) to assume the development of the project. Construction started the following year with the first turbine coming into operation in March 2000 and the second turbine six months later.⁹³ This concluded the first phase which saw 220MW of single cycle light crude oil (LCO) fired generation coming on line at a cost of US\$110m. The second phase of the Build Own Operate Transfer (BOOT) scheme, which would consist of a heat recovery unit and a steam turbine, was to be debt financed. This, however, did not materialise since the Ghanaian government and project sponsors could not

⁹³ CMS contracted Black & Veatch (US) and Overland Contracting Incorporated (a subsidiary of Black & Veatch) as the Equipment Procurement Contractor (EPC) to supply the main plant hardware for the installation enabling both firms to execute their first major power project in Sub-Saharan Africa. The Operating and Maintenance (O&M) responsibilities remained with the major shareholder through CMS International Operating Company, a subsidiary set up by the CMS parent company.

agree on the terms of the deal and, until present, the project has remained entirely financed by the shareholders' equity and operates without the steam cycle.

In March 2007, after experiencing financial difficulties in its home market, CMS announced that it would sell its share in TICO to TAQA, the Abu Dhabi National Energy Company.⁹⁴ The sale formed part of the company's wider divestiture strategy to exit emerging markets and refocus its operations on its domicile market. It was anticipated that the sale would allow CMS to reduce its corporate debt burden and strengthen its balance sheet (Berenson 2002; CMS pers.com. 2007; Ghana News 2007a).

CMS and TAQA were long-term allies and had partnered on infrastructure projects before. Although the takeover was a friendly one, the Government of Ghana protested, arguing that if CMS wanted to give up its share in the plant, it and the VRA (as co-shareholder) wanted to be informed of the negotiations and be given first option to purchase the shares. In addition, it argued that CMS should have sought its consent prior to setting up the new arrangement. The government went as far as claiming that it would refuse to recognize TAQA as a legitimate shareholder of Takoradi II (Awuni 2007; The Times 2007; Ghana News 2007b). While CMS acted within their rights in terms of the agreement, the Government of Ghana expressed its fierce resentment with the manner in which the deal was handled, describing it as improper and pronouncing that CMS was forcing Ghana into partnering with a company that it did not know. In addition, it was reported that the government was not happy with the US\$3m a month capacity charge that the deal benefited from (whether the power was used or not) and the controlling rights that the private investor enjoyed in the company (due to its majority shareholding), as these agreements were entered into by a previous political regime. The Government of Ghana advised CMS to hive off the Takoradi transaction from their talks with TAQA (The Chronicle 2007). Although the government had made an announcement of its intentions to acquire the total shares of the plant, the deal between CMS and TAQA was already near to completion (Ministry of Finance and Economic Planning 2007). The government did offer TAQA US\$30m to increase its shareholding in the plant to 50 per cent as per the initial shareholding agreement with CMS, but despite increasing its equity to 50

⁹⁴ Listed on the Abu Dhabi Stock Exchange, TAQA is a global energy investment company specialising in infrastructure projects in the Middle East, Asia, Europe and Africa. The sale of Takoradi II to TAQA was part of a larger transaction which comprised shareholdings in two large power and desalination projects in the United Arab Emirates, the Jubail Energy Company in Saudi Arabia, the ST CMS Company in India, and the Jorf Lasfar Energy Company in Morocco.

per cent, it reportedly was still eager to takeover the entire shareholding of the plant by mid-2008 (GGEA 2008; Yeboah 2008).⁹⁵

3.4.2 Project Agreements Cementing the IPP Deal

The absence of debt on the project and the large stake that CMS acquired meant that CMS has shouldered most of the investment risk. A long-term PPA of 25 years linked to a minimum availability ensured that the investors would be able to recoup their investment and make a return on the transaction. Like most IPPs in developing countries, PPA charges are dollar denominated to protect investors against currency devaluation. The PPA consists of a variable energy charge and fixed capacity charge (to which O&M is added). The project was also backed by a government guarantee.

The design of the original Takoradi site was such to provide for the Takoradi II expansion and to effectively double the facility's output from 330 MW to 660 MW.⁹⁶ The fuel arrangement for Takoradi I was also extended to accommodate the expansion, with the VRA assuming responsibility for the fuel supply to the IPP, since it was already supplying fuel to its own plant. The fuel is purchased by the VRA on international tender, supplied by tankers and piped to a single point mooring where it is stored in tanks for consumption. Since TICO would have no more control over fuel prices than would the VRA, it was agreed that the VRA procure the fuel for TICO in an attempt to synergize and avoid the duplication of logistics and procurement efforts. The responsibility rests on the VRA to procure the correct fuel specification to be burned by TICO and on the latter for ensuring that the fuel is burned in accordance with the heat rate curves as stipulated in the contract. The VRA being fuel supplier and power off-taker effectively reduced the arrangement to a tolling agreement with TICO and the sponsor, therefore, does not bear any risk for the delivery or quality of the fuel. It is expected that the plant will run on natural gas when the West African Gas Pipeline becomes fully operational.

⁹⁵ By the end of 2008, the shareholding in Takoradi II was still a 50/50 split between Taqa and the VRA.

⁹⁶ The expansion of the Takoradi site required a Supplementary Environmental Impact Assessment in 1999 from the Environmental Protection Agency (EPA) of the Republic of Ghana before the start of construction.

As part of the security package, provision was made for arbitration in the event of a dispute that could not be resolved internally between the parties involved. Arbitration provision is at the London Court of International Arbitration and covers the entire contract duration. With the urgent need for power, investors felt comfortable with the market risk since the demand for electricity was significant. A letter of credit with a value of US\$3m was, however, provided by the government. These security arrangements went a long way to securing the investment and attracting Ghana's first large-scale private power producer.

At an estimated 20.5 per cent rate of return on the project equity, the investor CMS reported that it was happy with the investment and, generally, with the outcome of the project (ECA 2003:28; CMS pers.com. 2007). There were no delays or major problems during the power station construction and thus far the plant has been operating well.

3.5 An Analysis of the Ghanaian Hybrid Market and its Performance

The electricity supply situation in Ghana has evolved over three decades from a situation where the country had an abundance of generation capacity and was the main exporter of electricity in the region to one where the country cannot meet its domestic electricity demand despite imports from its neighbours. A decade of power sector reforms (1998-2008) has not resulted in a meaningful improvement in the power supply situation in Ghana; instead, the situation has deteriorated. This section provides an analysis of how post-reform frameworks have fallen short of ensuring that adequate generation infrastructure is developed in a timely manner.

3.5.1 The Evolution to a Hybrid Market

The Ghanaian ESI has been subject to reforms since the mid-1990s when the government responded to the World Bank's policy of conditional lending to electricity sector projects in developing countries. The Government of Ghana responded to the World Bank's shift in policy by establishing the PSRC to deliberate the country's future power sector frameworks. Following the government's statement on the change in policy, plans were initiated to establish the required conditions in Ghana to secure private sector investment and participation in the development of the country's power sector infrastructure. These plans included an improvement of the operational efficiencies of the state-owned utilities in the sector and streamlining tariff setting in order for the process to be more transparent and independent of political interference from government. Envisaged under the structural

changes within the ESI was the unbundling of the sector and the gradual introduction of multiple generating companies, including IPPs, the creation of a number of distribution companies and the establishment of an independent regulator. Although the Ministry of Energy intended that a competitive power market would evolve, this has not occurred. In the generation sub sector, the VRA is still the dominant supplier of power and is complemented by one single IPP in the form of the Takoradi II thermal plant (by end-2008). The institutional reforms to accommodate the new policies comprised the corporatisation of the VRA, and the ECG under the Conversion to Companies Act. Furthermore, the hydro generation, thermal generation, and transmission functions were unbundled into distinctly separate departments within the VRA (RCEER 2005:29). While the VRA had been traditionally responsible for nearly all functions in the generation sector, with the new institutional arrangements, the mandate of licensing electricity operators, planning, and advising the Ministry of Energy became the responsibility of Energy Commission. The PURC assumed responsibility for economic regulation of electricity.

The existence of a dominant generator in the form of the VRA, and one operational IPP in the power sector, is typical of the hybrid arrangements that have appeared in the ESIs of many African states, despite an initial reform agenda to introduce competitive generation markets where a number of players compete for sales by bidding in price. Having settled at this intermediate state of power sector reform, the Ghanaian power sector has found it difficult to overcome the problem of insufficient generation capacity that the reforms, advocated by many, hoped to address.

3.5.2 Generation Planning: Changing of the Guard

Prior to power sector reforms, the VRA was responsible for planning in the power sector. The utility also conducted its own procurement and contracting with infrastructure construction firms in the sector. From the time of the utility's inception up until the time of the power sector reforms, the VRA enjoyed a large degree of autonomy with respect to the development of the power sector. Coupled with this independence, its relatively healthy financial and technical performances in the 1970s and 1980s, enabled the utility to negotiate international borrowing for project development and construction and to take the initiative for regional planning in West Africa (Brew-Hammond 1997:141). The VRA assumed responsibility for all aspects of project development and construction contracting as well as legal and financial arrangements to ensure fulfilment of power sector projects. In addition to technological capabilities within the VRA's Technical Services and Engineering and Design and

Construction Departments, the utility also had personnel both within and outside of the engineering departments that focussed on legal counsel, finance, as well as planning (Brew-Hammond 1997:154). The VRA also comprised of a Project Management Unit that had overall responsibility for contract administration and construction management (1997:192). With the reorganisation of the power sector, new institutions were set up to take over some functions from the VRA. For example, the overall planning function was moved from the VRA to the newly formed Energy Commission whose mandate also included the licensing of electricity utilities and setting up technical standards for operations in the sector.

Although the VRA had assumed responsibility for planning and development up until the final commissioning of projects, the Energy Commission's planning mandate is, however, limited to indicative planning (RCEER 2005:28). Considering project proposals, conducting tender processes and awarding contracts to the successful bidders of generation infrastructure providers does not fall within the ambit of the Energy Commission's stated functions. The VRA, under the new power sector policy, is no longer a power supplier of last resort and does not have any policy obligation or mandate to ensure adequate generation supplies for the country. Planning in the Energy Commission has not been extended to include responsibilities for financial, legal and environmental planning in ensuring that new generators come on line and often the envisaged timelines for developing additional capacity are not realistic.⁹⁷ Under the hybrid arrangement, therefore, it is less clear who assumes responsibility for the actual procurement and contracting of additional generation capacity, and it appears that the institutional framework to ensure the links between planning and dispatching of power is lacking. Although the Ministry of Energy is facilitating the development of generation projects (Adda 2007:8), the contracting processes and responsibilities have remained nebulous.

a) Allocating Generation Investment Opportunities: Private, Public or Both?

Currently, there are no clearly stated and agreed on criteria for allocating new build opportunities between state institutions and the private sector. The state-owned power utilities (VRA and ECG) are cash-strapped with little financial capacity to meet investment needs. Despite these difficulties and given the problems in attracting private investors to the power sector, state-led development of generation expansion is now also being pursued by the

⁹⁷ As an example, the Energy Commission's Strategic national Energy Plan has Ghana's first unit of nuclear power scheduled for the year 2018 allowing only five years for planning and another five years for construction (Energy Commission 2005:17). These arbitrary and optimistic schedules then form the basis for generation planning in Ghana.

government. Deciding on who will build new capacity additions, therefore, is not a function of clearly developed criteria for project allocation between public and private institutions, but rather, it appears to be the case where the government is campaigning for almost any investment, regardless of the developer. This is not surprising given the dearth of power generation due, in part, to the poor investment climate for private investors and the lack of funds of state-owned utilities. The government was not in a position to assist power sector development by making significant financial contributions due to limited resources for infrastructure spending that were already being depleted by outflows for electricity subsidies to residential consumers at the poorer end of the affordability spectrum. The government did, however, find sufficient funds to exercise its share option and increase its share in TICO to 50 per cent and, in 2008, expressed its desire to take over the entire shareholding of the plant. This move for increased or complete state-ownership in the only operational IPP, rather than inviting other private investors to the project, is in contradiction to the initial PPI policy which calls for increased private sector participation in power generation; the rationale for increasing state ownership had not been systematically formulated and the move to increase public shareholding in Takoradi sits awkwardly within the broader power sector policy framework.⁹⁸

3.5.3 Generation Procurement Frameworks

Although generation capacity planning has been conducted in Ghana to indicate the types of plant that would be required in each phase of the country's power sector development and although these plans are updated and revised periodically by the Energy Commission, the follow-on actions, including the initiation of the procurement process and finalising the contracting arrangements, have been problematic. Ghana has not yet initiated an ICB to procure private generation capacity under a long-term PPA. The country's first IPP was a

⁹⁸ The government's seemingly hostile reaction to incoming TAQA as the new shareholder to Takoradi II has also informed investors' overall perceptions of Ghana as a foreign investment destination for infrastructure investment. Although the government may be able to reduce the power charges if it increases its shareholding in TICO, with the difficulty in attracting finances to invest in generation it may be expected that the government would rather use whatever funds it had at its disposal to build more power stations, not buy back existing plants from private investors at a time where the country was in the midst of a power crisis. Although the rationale for the decision may be to reduce charges over the long-term, it does raise some questions around the ability to attract affordable power and the charges of future IPP transactions (the extent to which charges can be reduced and the ability of the government to match investors' expectations) given the country and sector's risk profile.

negotiated deal and none of the subsequent proposals have been put on open tender for contracting generation, but were negotiated directly with project sponsors. Despite the establishment of the Energy Commission and the PURC, these regulatory institutions had no input into the establishment of the Takoradi II IPP since they became operational only after the deal had already been finalised between the government, the private sponsor, CMS, and the VRA. The Energy Commission did not have time to develop licence conditions for IPPs and by the time construction was completed and the start of commercial operation was imminent, a provisional licence was issued to TICO in order to assume operations.⁹⁹

Established in 1997, but only becoming operational in 1998, PURC carried out an independent review of the fixed capacity charge the following year (1999), after financial closure was reached. Although the contract remained unchanged, it was concluded by the commission that the capacity charge should not be passed through in its entirety to consumers and thus it became a government contingency. Even if the PURC did have an opportunity to review the PPA during the early phase of the negotiations, it is doubtful whether a nascent regulatory institution would have possessed the necessary capacity and influence to effect any consequential changes to the agreements. With the energy crisis at its pinnacle, a review of the PPA could potentially have stalled the addition of the necessary capacity, a situation the government probably wanted to avoid at that time (PURC pers. com. 2007).

Avoiding potential delays in the development of the project was also a key reason for the procurement procedure followed in acquiring the much need generation capacity. The time constraint was one of the key reasons that Takoradi II was a negotiated deal as opposed to an ICB. It is, however, the government's intent that future plants are procured in an international competitive bid in order to attract the lowest priced power (Energy Commission pers. com. 2007). Regardless of this intent, Ghana has never developed a large-scale power plant through an ICB process. Moreover, there are no concrete plans for competitive bidding for future plants, showing a divergence between the country's policy intent and implementation, as well as possible weaknesses in planning and implementation within the sector.¹⁰⁰ It is for this reason that a number of stop-gap emergency plants had to be contracted in by the government.

⁹⁹ The licensing framework for energy service providers was only finalised in December 2006, and only in 2007 could the commission issue permanent licences to service providers, including TICO.

¹⁰⁰ International competitive bidding is traditionally a long process despite its efficiency in obtaining an optimal price. Careful planning and effective implementation is therefore critical to ensure that power plants come online before demand outstrips supply.

Procurement processes have also been problematic for the acquisition of these short-term power acquisitions where the necessary processes were not followed by government ministries, leading to arbitration cases between sponsors and the Ghanaian government for non-payment of services. A good example is as evidenced in the case of Faroe Atlantic, where the Ministry of Finance, the representative of the government, did not follow due process in seeking approval for the transaction, taking the view that such approval was not necessary (Oxford and Beaumont 2006:2).

While Takoradi II was a negotiated acquisition in 1998 when the power was desperately needed and a long tendering process may have delayed the commissioning of the plant, Ghana's more recent stated policies for the procurement of public infrastructure favour transparent and competitive bidding (PPA pers. com. 2008). The Ghana Public Procurement Authority is clear that, in accordance with the Public Procurement Act (Act 663 of 2003), where government procurement is concerned, goods should be competitively procured through a transparent tendering process.¹⁰¹ This, however, does not appear to be the current practice in Ghana and it would appear that in terms of generation procurement, Ghana is in contravention of its own procurement policies. Given the concerns of investors around off-taker financial ability to cover the PPA and the security arrangements required on the projects, it is expected that few investors would bid unless security arrangements are negotiated and clearly agreed on upfront. The government's stance is that it would prefer not to give government guarantees on IPPs as was done for Takoradi II. In the absence of such guarantees, it is understandable that significant time is spent in negotiations to allay the fears on investors. Often after long negotiations these projects still have not materialised as expected. The number of projects where negotiations have failed and project development stopped, are indicative of the problems in getting large generation infrastructure projects off the ground in a developing country such as Ghana. These include the Osagyefo project which still has to produce electricity despite the initial development having started more than decade ago and the plant completed in 1999, and the steam phase of the Takoradi II IPP for which negotiations were still ongoing a decade later.

The government has clearly stated its policy of moving away from providing sovereign guarantees for privately contracted power plants, in contrast to TICO. It should be reiterated

¹⁰¹ The law does make provision for specialised services where sole-source purchases are allowed (PPA pers. com. 2008). However, in the case single or combined cycle thermal plants are hardly considered specialised enough to be judged meeting the requirements for a sole-source acquisition.

here, however, that the sovereign guarantee for TICO was crucial in securing the deal. It is unlikely that CMS or any other investor would have entered into an agreement, given the fact that TICO was the first privately owned generator in Ghana, in a virgin regulatory environment, without such an assurance. In the generation planning process, a difficult investment environment has been created by moving away from government guarantees when the investment climate for infrastructure investment has not improved. Existing investment and contracting frameworks in Ghana's power sector do not work well in this environment. In part, this is due to the fact that it was not foreseen that the generation sector would be in a hybrid market arrangement for such a long period of time, as well as an expectation of an improved investment climate brought about the broader economic reforms of the country, which did not materialise as intended.

3.5.4 Contracting Arrangements between VRA and TICO

In the absence of an independent transmission system operator, the relationship between the state-owned utility and the IPP is vital since it is the VRA that is the off-taker of the power produced in accordance with a long-term PPA. This is typical of the hybrid arrangements in many African countries. In the case of the VRA and TICO, a number of factors have strained the sustainability of the contracting arrangements between the two parties and have undermined further investment in the sector due to a lack of finances on the part of the VRA and the subsequent wariness of potential private investors.

a) The VRA: Deteriorating Performance and Management Problems

The finances of the VRA were deteriorating at the time the Takoradi II IPP was negotiated. The drought situation (and as a result, lost revenue) as well as a severe currency devaluation were significant threats to the income stream that would recoup investors' outlays. In particular, the slow demise of VALCO, the traditional anchor to the Volta River project that paid in hard currency, threatened the utility's financial health, thereby putting the PPA, which was dollar denominated, at risk. The regulator put further pressure on the VRA's cash flows as it tried to find some degree of middle ground between protecting the public while ensuring the financial viability of the utility.

Although TICO has always had its power charges paid by the VRA and no disputes have been entered into between the parties, there have been a few occasions where the VRA was unable

to meet payment deadlines due to cash shortages within the organisation.¹⁰² In all cases, however, the charges were eventually settled by the VRA.

Since COD, the Takoradi IPP has had an average availability factor of 94 per cent (CMS pers.com. 2007). In contrast to the good performance shown by the single cycle Takoradi II, both the financial and the technical performance of Takoradi I, the combined cycle plant operated by the VRA, give cause for concern. Reasons for this appear to be four-fold. First, during the first years after Takoradi I was built, the plant operated only as a single cycle plant, i.e. not combined cycle, which meant that the unit cost was higher than had it operated as a combined cycle. Secondly, availability figures for VRA's thermal plant have been falling over the last few years (up until 2007), which appears to be linked to technical problems experienced by the plant. A third factor relating to poor performance stems from the VRA's cumbersome processes for acquiring spare parts whereby procurement decisions are not allowed to be made at lower levels within the organisation in the event of unplanned maintenance (KNUST pers. com. 2007; VRA pers.com. 2007).¹⁰³ Finally, with the company's weak financial situation has also contributed to the plant's current lacklustre performance.

The VRA has also suffered the impact of a management crisis. In 2002 and 2003, the company's Chief Executive came under heavy criticism from staff and middle management at the utility for his management style at a time of heightened concerns over the company's ability to supply the country with power. Amidst a sea of allegations of malfeasance and nepotism amongst other forms of corruption, increasing questions were asked with respect to the manner operations were conducted at the VRA and the sentiment was that the CEO was acting more in his own interest than in the interest of the utility.¹⁰⁴ After mounting pressure

¹⁰² This was mainly due to late payments by the government of subsidies granted to consumers (VRA pers.com. 2007). In 2003, subsidies owed to distribution utilities alone ranged from US\$400,000 to US\$1.4m (Asante 2006).

¹⁰³ Long-term service agreements for VRA's thermal have been proposed to remedy this situation.

¹⁰⁴ Amongst others, questions were raised by staff about two advisors, who had close connections to the Chief Executive and who were paid exorbitant monthly salaries. VRA staff also questioned the awarding of contracts for the renovation of the VRA headquarters in Accra and the revamping of VRA subsidiaries. The CEO came under criticism when he acquired a fleet of luxury sedans and 4X4s for the use of his senior management team in spite of the company's weak financial position. Further concerns were raised about the CEO's refusal to heed field officers' advice about the continued use of the Akosombo hydroelectric dam despite low water inflow. It was also alleged that the CEO had been involved in an extra-marital affair with a female employee from the VRA and had granted her unfair

from VRA staff to investigate, the government set up a committee of inquiry to probe these reports. Workers demanded his removal from office through protests and industrial action. At the pinnacle of the conflict between management and labour, the discord eventually resulted in the resignation of the CEO (after being prompted by his superiors) and the establishment of an Interim Management Committee to oversee operations until the management situation could be normalised (VRA Annual Report 2003). This period of instability at the VRA has certainly had some effect on the overall health of the organisation – in four years (between 2001 and 2005) the utility has seen as many leaders at the helm, during very difficult times.

b) PPA Charges and Generation Costs

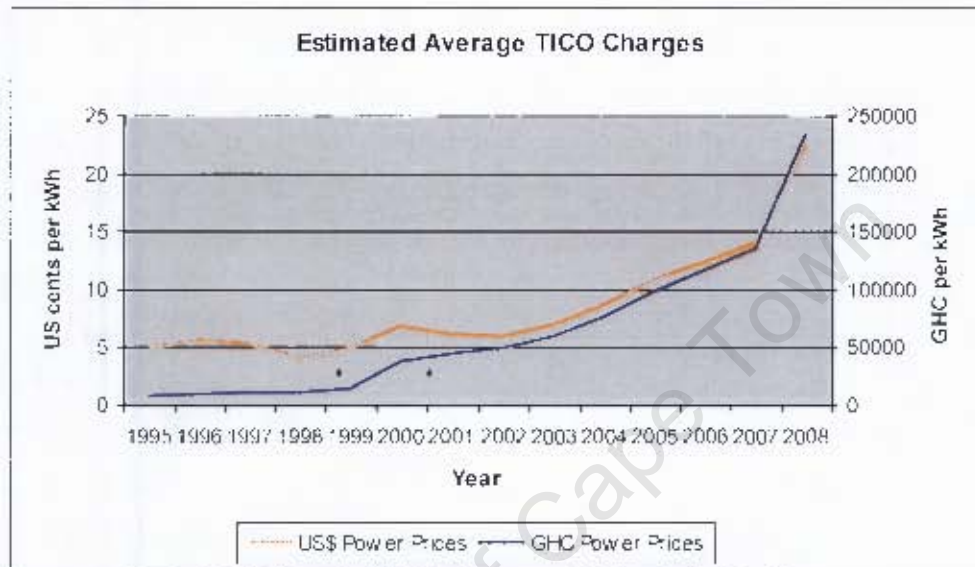
In contrast to the VRA thermal plant, the performance of TICO is supported by a guaranteed revenue stream due to the long-term power purchase agreement. The absence of project debt meant that the required rate of return (ROR) on the project was higher than would be the case if the weighted average cost of capital were to include the sizable portions of debt that are almost synonymous with classic project financing. Proportionally higher returns commanded by shareholders contributed to exerting upward pressure on tariffs. The 20.5 per cent return on equity reported on the Takoradi II project developed by CMS is not surprising given the level of risk of the country's first IPP. It has to be borne in mind that the intended project finance developments did not materialise, and had the project been refinanced with debt to expand the plant to incorporate the steam phase, a lower rate of return on the project would have been possible.

Since Takoradi II operates in single cycle mode, fuel costs remain by far the most significant component of generation costs, accounting for more than 75 per cent of charges (ECA 2003:39). The increasing fuel prices in recent years have had a significant impact on charges to TICO. In 1998, when the project was negotiated, world crude oil prices averaged between US\$11-12 per barrel. The situation in 2008 has changed dramatically, with oil prices having increased substantially. It is estimated that in mid-2008 monthly charges more than trebled since COD, and have increased more than fivefold when using fuel figures based on the price of crude oil at the time that the project reached financial closure in 1998 (see Figure 3.2). In comparison to the country's dominant hydro resources, this marks a significant increase in generation costs. More disturbingly, in cedi terms the charges increased more than six fold

benefits. It was also alleged that the former CEO froze promotions for managers who questioned his authorisation of what appeared to be fraudulent transactions in awarding of contracts (Ghana News 2002-2008: Dossier - Dr Charles Wereko Brobbey).

since COD and nearly 25 times since the year of financial closure. In addition to the fuel costs, the country's devaluing currency has exacerbated the local price of power from Tokoradi II.

Figure 3.2: Takoradi II Estimated Tariff Trend Based on Rising Fuel Costs



Sources: ECA (2003), VRA Estimates (2007).

*Project Closure was in 1998 and COD in 2000. Figures for 2008 is based on an average estimate of US\$119 a barrel (EIA 2008) and the average exchange rate for 2008 up until 26 August.

The poor financial state of the VRA resulted in insufficient funds being available for additional generation investment by the utility and in very little capital expansion and refurbishment projects being realised. While the IPP is assured of its revenues, the VRA has had to accept low tariff increases, the effect of which was eroded by high inflation. Increasing fuel costs for the VRA's thermal plants as well as the fuel costs that are passed through for the IPP have been for the VRA's account and laid claim to revenues that were decreasing due to droughts and, as a result, lower sales. The government's decision to increase the life-line electricity tariff band (for which domestic consumers do not pay) has also squeezed the utility's finances. These arrangements have made it harder for the government and the VRA as off-taker to attract and ensure further investment in generation since the sector was technically bankrupt.

c) Third-Party Access and Dispatching

Although there were some private sponsors who were still keen to invest in the sector, finding alternate arrangements to secure their revenue streams proved to be difficult. One example is the case of the mines that were adversely impacted by the electricity crisis in the country and proposed the development of an IPP to assist in power production for their own undertakings. The Ashanti/KMR plant described in section 3.2.2 did not materialise due to the VRA not allowing the sponsors to sell any of the excess capacity generated to VRA customers. In addition Ashanti/KMR and the VRA's VRA could not agree on a transmission price to wheel power through the grid to sell the excess capacity onto neighbouring countries. Due to failed negotiations with the VRA, the project did not continue. The Ashanti/KMR project is one example of how the single buyer arrangement can be problematic when the buyer is also seller of power and this conflict of interest frustrates investment. This allowed the VRA the opportunity to screen out sponsors who want to sell power directly to VRA customers by adding wheeling charges that make projects uneconomic. Since transmission tariff pricing was performed internally in the VRA, it had a great deal of control over who could enter the market and, in so doing, discouraged private entry into the market. Such behaviour is often observed when inadequate governance arrangements have been made to prevent this kind of behaviour by SOEs. It has to be borne in mind, however, that the standard model of reform envisaged that transmission operations and payment systems would have been completely independent and ring-fenced from state-owned generators; however, due to stagnated reforms this has not happened. It has allowed behaviour by SOEs that could undermine the objective ensuring adequate generation capacity through reforms.

3.6 Conclusion

In summary, Ghana's hybrid power market emerged with the building of the country's first IPP, which was developed before any substantial institutional changes in the sector came into effect. The country instituted power sector reforms in part to deal with the problems associated with under-investment and a shortage of electricity in the country. The first phase of the Takoradi II IPP was installed rapidly at the request of VRA and the Ministry of Mines and Energy to meet emergency power shortages that existed in 1998. The urgent need for power influenced the procurement and contracting options chosen by the government for the project and may have placed the off-taker in a disadvantageous position during negotiations with CMS. In addition to this being the first IPP in a sector in the throes of reform, the investment climate in the country was less than favourable at the time, and the power off-taker's financial position was precarious at best. Nevertheless, without private capital to fund

the first phase of Takoradi II, load shedding would probably have been worse in Ghana. The Ghanaian government therefore agreed to the terms of the plant sponsors who benefited from an attractive return on the investment and a state guarantee. Although transformation and the establishment of reformed institutions only developed in earnest after the development of the Takoradi II IPP, the functioning of the regulatory and institutional frameworks have been largely unsuccessful in enabling the attraction of further investment capital for additional generation capacity.

Despite power sector reforms to spearhead private investment in generation, the challenge of attracting investors on equitable terms remains formidable. Subsequent to the Takoradi II IPP, no new privately financed large-scale plant has been commissioned and the distribution sub-sector has not been primed for private sector participation as initially intended. The number of plants that were negotiated in Ghana but never realised at periods when the power was badly needed, further supports the judgment that the enabling environment for IPPs had not been created.

Institutional frameworks and their functioning have been inept at securing adequate investment in and contracting of generation capacity. The required governance functions to improve state-owned utility performance have been lacking in critical areas and have contributed to the prolonged underperformance in operations. Inadequate state support for the operational health of these utilities has also not helped to improve their technical and financial performance. Despite the establishment of independent regulatory institutions to oversee the sector functioning and ensure positive long-term operational performance, the erosion of their independence has turned them into blunt instruments for rubber stamping the political interests of the ruling party in Ghana, rather than ensuring the sustainability of the sector. The real value of tariff increases has been eroded by high inflation and, in conjunction with steeply increasing fuel prices, the government's apparent need to protect consumers from high tariffs through subsidies has sent mixed signals in the context of its stated mission to strive toward cost reflective tariffs and make the sector financially sustainable to attract additional investment.

The transfer of functions relating to planning, procurement and contracting of power sector infrastructure to the Energy Commission from the VRA has also resulted in a lack of clarity and confusion with respect to agencies that are responsible for the allocation of new build opportunities, as well as procurement and contracting frameworks for new investment. The lack of clearly allocated responsibilities for procurement and contracting of additional generation has created opportunities for inconsistencies between policies and practice. The

lack of an independent system operator may also have contributed to the problem of insufficient generation capacity. Having the VRA as off-taker while at the same time allowing it to influence third-party access, may have resulted in at least one project (KMR/Ashanti) not going ahead due to a possible conflict of interest.

Included in the Government of Ghana's 2004 new policy framework for reform in the power sector, was the objective to become a net power exporter by 2008 (Kusi 2005). Objectives like these have been missed and will continue to be missed unless policy, regulatory and institutional frameworks are altered to respond to the conditions that are required to promote the improved functioning of the hybrid power market, especially with regard to more effective planning, procurement and contracting of new power.

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CHAPTER 4

POWER SECTOR REFORM IN CÔTE D'IVOIRE

Côte d'Ivoire is one of the few countries in Sub-Saharan Africa that has transformed its power sector to a stage where there is no state involvement in the daily aspects of utility operations. Two difficult rounds of institutional reforms have helped the power sector to get on track after poor performances registered in the 1980s. Unlike many other African countries where the SOEs are dominant and IPPs operate on the periphery, the bulk of Ivorian power production is accounted for by IPPs and the remainder is supplied by a private contractor that operates power sector assets on behalf of the state through a long-term lease agreement. Hence, all power is produced by private operators in the sector. This arrangement presents a different form of the hybrid model from the norm in African power sectors and allows for an interesting evaluation of the policy, regulatory and institutional frameworks that have had an impact on the sector's ability to encourage investment in generation.

With the state's involvement limited to overseeing operations in a governance role, the daily operations of the sector have been depoliticised paving the way for incentives to facilitate performance improvements in the technical and financial arenas. The power sector has seen two rounds of institutional reforms that have enabled it to respond reasonably well to the challenges of hybrid markets and the attraction of investment in generation. The departments responsible for planning and procurements under the dominant SOE model in generation were retained to provide a similar function when private sector participation was ushered in; thereafter these functions were simply transferred to state agencies reporting to the Ministry of Energy.

The involvement of prominent multilateral and bilateral development finance institutions have shaped procurement processes of these agencies and, in some ways, have ensured that there are adequate governance mechanisms to ensure that the single buyer framework responds adequately to the challenges of the market and creates sufficient certainty to sustain investors' interest in the generation sector.

4.1 Introduction

The Republic of Côte d'Ivoire is one of the pioneers on the African continent with respect to reforms in network industries and private participation in public infrastructure. As far back as 1959, before the country's independence, the city of Abidjan launched an international tender (to French companies) to manage the city's water distribution system (Lavigne 1999:83). The contract was awarded to Société d'Aménagement Urbain et Rural (SAUR) of France who, in 1960, established Côte d'Ivoire's first private water distribution company, SODECI (Société de Distribution d'Eau de Côte d'Ivoire) to provide water services in Abidjan.¹⁰⁵ The city's water services showed significant improvements from the previous state-controlled utility and the outcome of the new long-term lease agreement was regarded as largely successful. In 1974, when the central government assumed responsibility for the water sector, it was decided to expand the water lease agreement to cover other Ivorian cities as well and SODECI signed a 15-year lease agreement with the Government of Côte d'Ivoire. The company sustained a steady increasing performance, providing high water quality, attaining high worker productivity, achieving high collection rates from private consumers, and reducing system losses to a minimum. As a result, the contract was renewed in 1987 for a further twenty years (Bayliss 2001).

Côte d'Ivoire was not only the first African country to invite private sector participation in its water sector, it was also the first African country to introduce private sector participation in its power sector in 1990, when the management of the country's electricity utility was handed over to a private operator. By 1994, IPPs were starting to contribute to the country's electricity generation and, by 2007, IPPs accounted for nearly two thirds of national electricity production. By 2008, the Government of Côte d'Ivoire was also in the process of preparing bids for a third privately contracted power plant, for which construction is scheduled to start later in 2009.

Despite the progress made in the power sector over the last two decades, reforms did not come without some challenges. The country has experienced severe droughts, significant currency devaluation immediately pre-IPPs, political unrest, and a suspension of a large part of revenue from power sales for an extended period.

¹⁰⁵ Until then, traditionally municipalities had been responsible for the for water supply services but due to insufficient financial and technical resources were unable to operate the systems efficiently or make provision for system expansion (Kerf 2000:5).

This chapter evaluates the Ivorian experience in attracting investment for generation and is structured into four parts. Immediately after this brief introduction, an overview is given of the electricity supply industry, the main stakeholders and the reforms that have taken place to date. Thereafter, the subsequent section details the IPPs that have supplied power to the national grid since reforms were initiated in the sector. In the final section, an analysis is made of the factors which have contributed to, or have hindered, private investment in generation capacity. The specific challenges that arise in hybrid power market are identified.

The information presented in this chapter draws on detailed interviews with key stakeholders in the Ivorian power sector during a country visit. Interviews were conducted with representatives from the Ministry of Mines and Energy in Côte d'Ivoire, the Compagnie Ivoirienne d'Electricité (CIE), the Compagnie Ivoirienne de Production d'Electricité (CIPREL), Azito Energie, and the Autorité Nationale de Régulation (ANARE). Subsequent correspondence was conducted to clarify discussion points and to probe further issues with the abovementioned representatives, including staff from the World Bank that have been involved in, and observed, the reforms in Côte d'Ivoire. Throughout the text, stakeholders have not been identified by name but only by organisational affiliation.

4.2 The Ivorian Electricity Supply Industry

From as early as 1952 and until 1990, the state owned utility, Energie Electrique de Côte d'Ivoire (EFCI), exercised a monopoly over the generation, transmission and distribution of power in the country.¹⁰⁶ From the period before independence until 1980, the utility operated reasonably well with relatively good technical and financial performance and few institutional problems. Poor performance started to creep in during the early 1980s and worsened until the end of that decade. Since 1990, reforms in the power sector have helped to put the utility on a firmer footing with significant private participation.

4.2.1 Generation

At the time of Côte d'Ivoire's independence in 1960 the installed generation capacity was at 35MW. After the country's independence, plans were put in place to develop Côte d'Ivoire's hydro potential. During the 1970s, however, most of the growth was attributed to

¹⁰⁶ Prior to the 1950s, certain municipalities were responsible for electrical generation and distribution (Lavigne 1999:83).

In 2006, hydropower accounted for 27 per cent of generation, the rest being made up from thermal sources. The IPPs, CIPREL and Azito, accounted for 27 per cent and 39 per cent of generation respectively, with the balance contributed by Vridi I (Ministry of Mines and

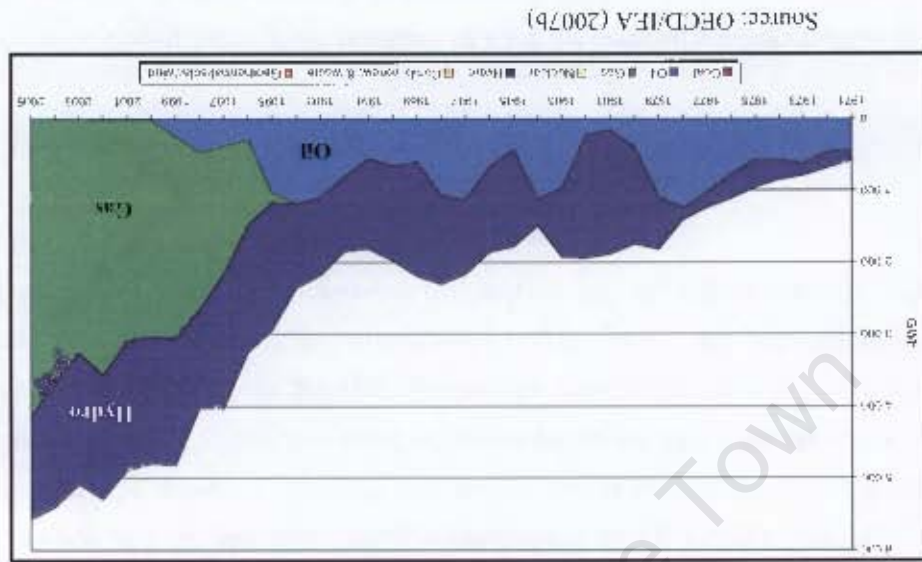


Figure 4.1: Evolution of Electricity Generation by Fuel in Côte d'Ivoire.

4.1. The generation mix has thus changed considerably over the past four decades. Thermal plants accounted for roughly two thirds of electricity generated, as depicted in Figure 4.1. Since the discovery of gas in the mid-1990s, growth has been, once again, mostly thermal, and by 2008, despite an approximate 50/50 split in hydro and thermal generation capacity. country's thermal electricity resources. Vridi I was followed by two IPPs, CIPREL and Azito, which strongly augmented the increased thermal generation capacity, load shedding was still pervasive throughout the Electric to make up for the shortfall in electricity supply (CIE pers. com, 2007). Despite the by the state in 1984 when EECI ordered four 25MW emergency gas turbines from General term view to have a 50/50 split between thermal and hydro generation. Vridi I was installed generation. A plan was formulated to complement hydro with thermal capacity with a long- utility when a drought spread through West Africa and resulted in a shortage of power complement of hydro capacity, 1984 was one of the worst years for the hydro-dominant 333MW was from hydro and thermal sources respectively (Vel 1999:17). Despite the large 1984, the country's production capacity had increased to 937MW of which 604MW and dominant source of electricity (albeit briefly until the drought period) in Côte d'Ivoire. By commissioned diesel plants and it was not until the 1980s that hydropower became the

Energy 2006). IPPs, therefore, accounted for approximately two thirds of national production in 2006. Table 4.1 gives a breakdown of the installed capacity in Côte d'Ivoire as of 2007.

Table 4.1: Installed Electricity capacity in Côte d'Ivoire

Plant	Year	Installed Capacity	Type
Ayame I	1959	20	Hydro
Ayame II	1965	30	Hydro
Kossou	1972	174	Hydro
Taabo	1979	210	Hydro
Buyo	1980	165	Hydro
Fayé	1983	5	Hydro
Vridi I	1984	88	Thermal
CIPREL IPP	1995	210	Thermal
Azito IPP	2000	300	Thermal

Source: Ministry of Mines and Energy (2008)

Despite the recent growth in thermal power generation resources, hydro remains an important actual and potential source for electricity production in Cote d'Ivoire. The state is presently planning a new hydro plant, Soubré, with a nominal capacity of 300-350MW, which is expected to be bid out to the private sector and be the country's first hydro IPP. This project has, however, met with considerable delays due to the civil conflict and is now expected to be operational only in 2014, provided negotiations are successful (IWP&DC 2006; Ministry of Mines and Energy pers. com. 2007).

Meanwhile, as of 2007, the state has engaged the two existing IPP consortia in negotiations for additional generation. CIPREL has already started the conceptual development of the next phases of thermal capacity. Should the company be given the go-ahead to develop the next tranche of thermal capacity, it will consist of another 110MW open cycle gas turbine by General Electric, which would constitute the third phase of the project (with phases one and two detailed later in section 4.4). A fourth phase is planned where exhaust gases from the two existing 110MW turbines will be combined to be used in a steam cycle, adding another 110MW to the plant's output. If this is realised, CIPREL would be among the largest gas-fired IPPs in West Africa with an output of 540MW. The state has also been in discussions with Azito Energie to expand its capacity through the development of a steam cycle, which would use the exhaust gases from its two gas turbines.

4.2.2 Transmission and Distribution

Côte d'Ivoire is electrically linked to its immediate neighbours through regional transmission interconnections.¹⁰⁷ While coping with a stagnant domestic demand market between 1999 and 2004, the state has benefited from these regional transmission exchanges by exporting power to Ghana, Togo, Benin, Mali and Burkina Faso (Amuna, Modey et al. 2002; Ahoussou 2005).¹⁰⁸ In fact, Côte d'Ivoire has gone from a net importer of power in the 1980s and early 1990s to being the main electricity exporter in the West African region. In 2005, more than a quarter of the national production was exported to the country's neighbors, and it is the government's policy to maintain the country's status as a power provider to the region (Ministry of Mines and Energy 2006).

Although regional power exchanges allow Côte d'Ivoire's neighbours to benefit, a large part of the country's population has not been fortunate enough to gain access to electricity. In 2005, roughly a quarter of the rural population had access to electricity compared to 77 per cent in urban centres, with Abidjan having an access rate of 88 per cent (AfDB/OECD 2006:240). Roughly 72 per cent of villages in the country have access to electricity; however, due to low penetration rates this equates to only 30 per cent of the total population having access (Ministry of Mines and Energy pers. com. 2007).¹⁰⁹ Although rural electrification plans were initiated in the early 1980s, serious difficulties experienced in the management of the sector, the economic crisis of the 1980s and the severe droughts forced the suspension of these programmes for several years (Diaz and Perault 2002). The rural electrification programmes resumed again only in 1991, gaining momentum when a Special Group for Rural Electrification, GSPER (Groupement Spécial Pour l'Électrification Rurale) was formed in March 1995 to oversee implementation. After the 1998 restructuring (described in section 4.3), an Ivorian Electricity Operations Company, SOPIE (Société d'Opération Ivoirienne d'Électricité), was mandated to oversee the implementation of the rural electrification programme as part of its mandate of network planning (Vanie 2000).

¹⁰⁷ The country operates a transmission system at the 225kV and 90kV level (Vei 1999).

¹⁰⁸ After the political coup in December 1999, demand for electricity was dampened due to the socio-political tensions that erupted in the country.

¹⁰⁹ Despite the seemingly low access rates, they represent a steady increase in electrification since the country's independence in 1960 when only 14 towns and villages had access. This number increased to 108 in 1970, 475 in 1980, 1027 in 1990, and 1400 in 1997 when electrification was expanded to cover all of the sixteen administration regions in Cote d'Ivoire (N'Guessan 2000:27).

4.2.3 Fuelling the Power Sector

Petroleum discoveries in Cote d'Ivoire were made as early as 1952 when geographical surveys were conducted by the Bureau de Recherche Pétrolières (BRP) and the Société Africaine des Pétroles (SAP). Drilling continued until 1962 when these organisations withdrew after drilling ten dry wells onshore (UNDP/World Bank 1985:13). Offshore discoveries have occurred since the 1950s, but these were limited until the 1970s when large reserves of oil were found. Although exploration efforts first discovered large reserves of natural gas, along with oil, in the 1980s, it was not until the mid-1990s that the natural gas resource was developed for power generation (EIA 2008). Since 1990, with assistance from the World Bank, the African Development Bank and the Japanese government, the Government of Cote d'Ivoire has sustained interest in the country's hydrocarbon sector with exploration incentives and promotion campaigns (World Bank 1995c:3). Both IPPs use natural gas as the primary energy for power production along with the state owned Vridi I, and presently the electricity supply industry (ESI) constitutes about 97 per cent of the national gas demand (ANARE pers.com. 2007).

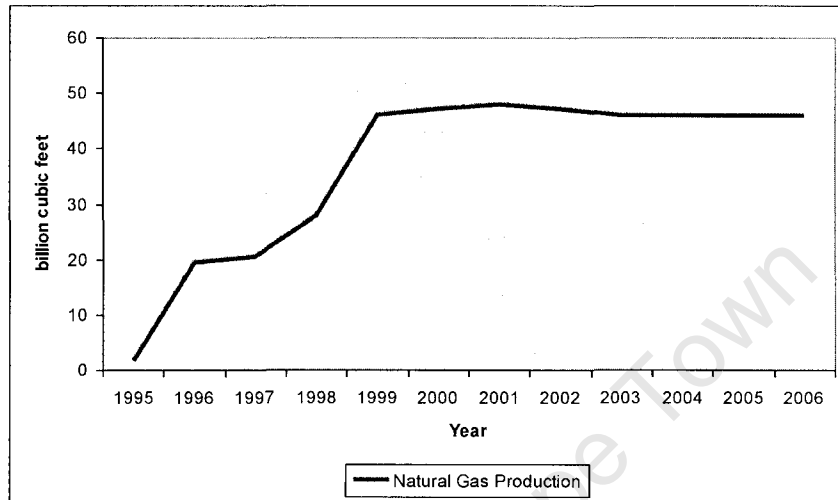
It is estimated that Cote d'Ivoire's proven gas reserves (at 1.1 trillion cubic feet) are sufficient to fire the existing plants for the next two decades. The plan for new plants, including those noted in section 4.2.1, however, reduces the proven reserve life to approximately 10 years (AfDB/OECD 2004; Ministry of Mines and Energy pers. com. 2007). Thus, either significant growth in the country's gas exploration is needed or other alternatives must be identified to fuel the growing number of generators.

It is envisaged that the West African Gas Pipeline (WAGP), which will distribute Nigerian gas to Ghana, Benin and Togo, may eventually be extended to other coastal West African countries, including Cote d'Ivoire. This could help relieve the state of its obligations to ensure that domestic gas fields remain dedicated to power production and IPPs, for which it (the state) assumes the fuel risk. In addition, the extension of the pipeline would also afford Cote d'Ivoire the opportunity to sell its gas to neighbouring countries.¹¹⁰ In the meantime, that is,

¹¹⁰ In April 1999, a Memorandum of Understanding (MoU) was signed between Cote d'Ivoire and Ghana for a feasibility study to build a gas pipeline between the two countries (NIGC 2001). After the coup d'état in December 1999, progress on the MoU came to a halt, and Ghana decided to put all its efforts behind the development of the WAGP.

until such time that WAGP provides a viable alternative, domestic exploration efforts continue.

Figure 4. 2: Côte d'Ivoire Natural Gas Production (1995-2006)



Source: International Energy Agency (2007)

As illustrated in Figure 4.2, gas production increased steadily from the mid-1990s until the end of 1999 when a coup stopped most significant exploration and development projects in the sector. The domestic gas industry, which to date has been critical in containing electricity prices by avoiding more costly imports, is made up of three main suppliers: Devon, Canadian Natural Resources (CNR) and Foxtrot (with Bouygues and EDF as shareholders).¹¹¹ All three firms contract directly with the state, which manages fuel contracts for all plants, including the two IPPs.

4.2.4 Tariffs and Revenues

Tariffs are set by the state, primarily by the Ministry of Mines and Energy, taking into account an array of factors such as the financial viability of the power sector and consumer affordability. Tariff setting has generally sought to achieve a balance between revenue and

¹¹¹ Devon operates two offshore gas fields, viz. Lion and Panthere in Jacqueline, Foxtrot International operates the Foxtrot gas field (the largest gas field in Côte d'Ivoire) in the same zone, and CNR operates the Espoir field west of Abidjan (CIPREL 2006). The Espoir field operated by CNR provides both oil and gas whereas the fields developed by Foxtrot and Devon provide only gas (ANARE pers.com. 2007). Devon was formerly known as Ocean Energy and Foxtrot was known as Apache.

total costs in the sector, including provision for rural electrification, network expansion, debt service and payment of the various operators in the sector, although more recently, revenues have been insufficient to cover rural electrification, transmission network expansion, and other large capital projects in the sector (N'Guessan 2000:30-31).

Electricity tariffs in Côte d'Ivoire were increased in 2001 (ANARE pers.com. 2007; CIE pers.com. 2007) when the sector saw a cumulative deficit due, in part, to a tariff structure that was not cost reflective and arrears in payments by Ghana's Volta River Authority (AfDB/OECD 2004).¹¹² Since the 2001 tariff adjustment, however, no further action was taken to reflect the increased cost of production, until February 2008, when tariffs were increased to partially reflect increasing fuel costs.¹¹³ In spite of the increase, tariffs are still considered low and ultimately do not reflect the LRMC; while operating costs of the utility, private producers and fuel suppliers are covered, revenue from tariffs does not cover the cost of additional investment in infrastructure (Ministry of Mines and Energy pers. com. 2007). Finally, it should be noted that the government subsidises consumption for all residential customers (regardless of income) up to 80 kWh over two months, which amounts to a rate of roughly 35 FCFA/kWh (AfDB/OECD 2006).¹¹⁴

In addition to the relatively low tariffs, since the period of civil unrest which started in September 2002, roughly 15 per cent of the utility's revenue has not been forthcoming; customers residing in the northern area, controlled by the rebels, have ceased paying their bills. This has resulted in large losses for the utility and edged the electricity sector's finances into the red for the first time since privatisation (AfDB/OECD 2004). Following the ceasefire peace agreement (signed in early 2007), money is slowly starting to trickle in again. However, a significant turnaround in the situation is only expected after a prolonged period of political stability (Ministry of Mines and Energy pers. com. 2007).

As previously noted, Cote d'Ivoire has benefited from its neighbours' electricity supply crises. During this time of revenue loss and stagnant growth in domestic demand, greater

¹¹² The tariff basket was reorganised to make tariffs more socially acceptable after the 1999 coup d'état, which involved a 10 per cent weighted increase (ANARE pers.com. 2007).

¹¹³ The price of gas is normally indexed to the price of crude oil and is paid for in foreign currency. In 2001, the average price of crude oil was US\$23 a barrel. In January 2008, it was more than US\$80 a barrel.

¹¹⁴ 1€ = 656 CFA francs.

amounts of energy were available for export, with payment for electrical power made in hard currency. In 2005, exports totalled 1397 GWh (Ministry of Mines and Energy 2006). This nearly equalled the guaranteed capacity of CIPREL, which is 1410 GWh per year.

4.3. Power Sector Reforms

Private participation in Côte d'Ivoire's power sector may be attributed to a number of factors including its strained economic conditions, and its long relationship with the International Monetary Fund (IMF) and the World Bank. Nevertheless, like its neighbour, Ghana, it was a severe drought that played a significant role in prompting the country to embark on reforms.

4.3.1 Drivers of Reform

Although the EECI had operated reasonably well until 1980, a series of events adversely affected the financial and technical performance of the utility. Severe droughts between 1983 and 1985 led to a significant reduction in sales and put the utility in a precarious financial situation. The prolonged drought undermined peaking capacity as the minimum levels in the reservoirs were depleted and could not support peak loads (UNDP/World Bank 1985:x). In addition to the low sales associated with the drought, the acquisition of four emergency turbines, exacerbated the already dire fiscal state of the utility.¹¹⁵ Despite tariffs being

¹¹⁵ During the first two decades after Cote d'Ivoire's independence, the country enjoyed strong economic growth, averaging 7 per cent per annum. Between 1972 and 1980, demand for electricity grew at an average rate of 13 per cent per annum, mainly driven by industry and commerce, which represented an increase of 14.5 per cent in the medium to high voltage categories. This increase in demand was met by an increasing contribution of hydro-electricity. By 1981, hydro generation responded to roughly 80 percent of national demand compared to 30 per cent in 1972 (UNDP/World Bank 1985:7). Economic growth and electricity demand stopped when a worldwide recession in the early 1980s impeded the growth of Ivorian exports. A precipitous drop in the country's primary export commodities, viz. cocoa and coffee, led to a sharp decrease in government revenues, which were normally accumulated, from tariffs levied on external trade. Coffee and cocoa dropped by more than 50 percent in 1980 from the peak reached two years earlier (UNDP/World Bank 1985:1). By 1983, the country had experienced three years of negative GDP growth totalling a 20 per cent decrease in GDP per capita between 1980 and 1983, and, by 1983, the country's external debt equalled its GDP. The effects of the drought in 1983 resulted in an over-reliance on imported petroleum products for electricity production and increasing fuel prices contributed to the fiscal problems of the EECI, accounting for a major portion of the consolidated debt of the public sector (UNDP/World Bank 1985:10). In 1984, the government announced a series of austerity measures aimed at increasing the

adjusted upward in 1984 to offset the increasing operating and fuel expenditures, the utility could not cope with the financial strain that the drought and global economic downturn had on the power sector (UNDP/World Bank 1985:iv).

In addition, the power sector's institutional arrangements were considered too weak to cope with strategic issues, especially in the context of the unfavourable conditions that the sector was in at the time. A joint UNDP/World Bank report noted that "*The energy sector in the Ivory Coast suffers from a weak and poorly coordinated institutional infrastructure. No one institution has been given primary responsibility for energy planning and policy formulation. Areas of responsibility are divided among various ministries. Institutional issues involving coordination among public and semi-public enterprises need to be resolved, particularly in the key sub-sectors, power and hydrocarbons*" (1985:xviii).

From 1985 to 1990, a number of multilateral and bilateral lending agencies strongly recommended restructuring of the EECI. While management overlooked most of the recommendations for improved financial management, the Government of Côte d'Ivoire did institute legal changes to the ESI through the enactment of law No. 85-583 of 29 July 1985 (Republic of Côte d'Ivoire 1985).¹¹⁶

The law ended the state monopoly in generation and authorised the entry of IPPs provided that electricity was generated and distributed locally using production sources and facilities authorised by the state (articles 3 and 8c). The law also made provision for concession agreements for private operators to manage the generation, transmission and distribution of electricity (article 5).

Interestingly, since at the time the most pressing problem was the lack of funds to sustain the power sector, the law obliged the sector to balance tariffs with all charges (articles 8a and 9), including payments to private operators and charges for network expansion and electrification. N'Guessan (2000:33) notes that, "*The only specific goals assigned to power sector reform were to stop the financial mismanagement and restore financial equilibrium in*

fiscal status of the public sector. They included cuts in government spending, wage freeze provisions for public servants, and restructuring of various tariffs and prices (UNDP/World Bank 1985:2).

¹¹⁶ Interestingly, the law made provision for private sector participation in the ESI a few years before the UK, considered one of the earliest reform pioneers, enacted legislation to privatise its power sector.

the sector". Despite the legal changes introduced to usher in reforms, it took a further five years before structural changes to the power sector were realised.

By 1988, the country was forced to suspend its electrification programme due to insufficient funds and, despite having amongst the highest tariffs in the world at that time, with the organisation's losses almost equalling its operating revenues, it could not repay its debts and had difficulty paying its workforce (Diaz and Perault 2002:7; Jones, Jammal et al. 2002:1-13). In 1990, the EECI's debt totalled about US\$350m; its billing rate was under 85 per cent, and the billing recovery rate stood at 70 per cent (ANARE 2005b). The World Bank's Staff Appraisal Report (1995c:5) states that by the end of the 1980s, the EECI was insolvent with losses totalling more than US\$240m. The multiple causes included the country's economic crises,¹¹⁷ overexpansion, and mismanagement in the electricity sector.¹¹⁸

By this time, pressure was also mounting on the state to take action to address the mismanagement of public enterprises. Being one of the largest state-owned companies, the restructuring of the EECI was one of the most important priorities for multilateral lending agencies, including the World Bank, the main lenders to the Ivorian power sector (N'Guessan 2000:32).

With no domestic financial reserves to spare, the country turned to the World Bank and the IMF for assistance. On the bank's recommendation, it was decided that Côte d'Ivoire would engage private sector participation and reform and restructure its electricity industry. Hopeful of replicating the success that had been seen in the country's water sector, the president acted swiftly and started negotiations with Bouygues of France in May 1990. Within six months an agreement was reached with Bouygues and on 20 October of that same year the agreement was signed for a new private operator to take charge of the management of the national utility.

Société d'Aménagement Urbain et Rural (SAUR - which was involved in a long-term lease agreement in the water sector), an affiliate of the Bouygues Group, together with Electricité de France (EDF) agreed to take over the management of the utility for a period of 15 years,

¹¹⁷ At the time, cocoa and other export commodity prices dropped sharply, and the country's debt situation made it difficult for the state to aid the utility financially.

¹¹⁸ Brew-Hammond (1997:309, 314) notes that the financial losses of the EECI were tolerated and overlooked for a long period since its politically powerful CEO enjoyed protection afforded to him by his close relationship with the president.

with the contract renewable twice for three years (Ahoussou, 2005).¹¹⁹ Compagnie Ivoirienne d'Electricité (CIE) was formed with SAUR and EDF assuming 51 per cent of the shares to have controlling rights in the company (Fall 2004). Of the remaining 49 per cent, 20 per cent is retained by the Government of Côte d'Ivoire and 29 per cent by private and employee investors (Vei 1999; NIGC 2001).

The scope of CIE's contractual obligations included the operation and maintenance of the utility's assets, but the company was not obliged to undertake major refurbishments and capital expansions – these responsibilities remain with the state. The turnaround in performance with CIE was almost immediate with no retrenchments happening during or after the takeover.¹²⁰

Although the private companies brought in the necessary funds for the utility to operate satisfactorily again, helped in part by improved hydrology, the threat of adverse weather conditions and inadequate supply remained, with the utility operating just one thermal plant at the time. In keeping with the overall reform and restructuring goal first espoused in 1985, in 1994, the government turned to Bouygues, and negotiated Côte d'Ivoire's and Sub-Saharan Africa's first IPP, Compagnie Ivoirienne de Production d'Electricité (CIPREL). IPPs came at a critical juncture in 1995, which saw the culmination of the number of events; the president was to stand for re-election in October 1995 and his goal was to ensure the security of electrical supply for the elections since power outages were one of the main causes of the social unrest which had erupted in certain areas in Abidjan¹²¹; substantial quantities of natural gas were found off the Ivorian coast which, instead of being flared, could be used for thermal power generation; and the four turbines at the Vridi plant could be rapidly converted to burn natural gas (N'Guessan 2000:36). Less than two years after CIPREL was commissioned, the government contracted a second IPP, Azito, to satisfy the country's electricity demand that was fuelled by bullish economic growth.¹²²

¹¹⁹ A new contract was signed between the Government of Côte d'Ivoire and CIE for another 15 years, on October 12, 2005 (CIE Annual Report 2005).

¹²⁰ Jones, Jammal and Gokgur (2002:1-6) elaborate how the company retrained excess female workers as bill collectors on the premise that it was hard to say no to a young woman.

¹²¹ Any unplanned outages led to pervasive load shedding commensurate with that experienced during the droughts of 1983 and 1984.

¹²² In December 1999, however, the country experienced a coup, after which economic decline, political unrest and instability followed. It is only since 2004 that Cote d'Ivoire has seen positive

4.3.2 Institutional Reforms

With the CIE assuming responsibility for the management and operation of the national utility, the role of the EECI was reduced to: oversight and expansion of the assets; of the technical operations of CIE; and management of the finances and general accounting of the power sector. To this end, the Government of Côte d'Ivoire set up three structures: an oversight organisation to supervise and coordinate the activities of the CIE; a technical commission responsible for preparing tender documents, evaluating submissions, and drafting contracts¹²³; and a national supervisory function to oversee the activities of the EECI relating to engineering projects in the power sector (N'Guessan 2000:41).

Given that the finances of the power sector was the main driver of reform, on 28 April 1994 the Government of Côte d'Ivoire enacted a further decree for the establishment of the National Electric Energy Fund, FNEE (Fonds Nationale de l'Energie Electrique), with the primary purpose of ensuring that the finances of the power sector were healthy and that charges were covered by tariffs (FNEE 1994).¹²⁴ The reporting structure of the power sector was also modified to enable the Ministry of Energy and Ministry of Finance to have joint responsibility for the sector: the Ministry of Energy to ensure that the technical planning and operations of the sector are adequately provided for, and the Ministry of Finance to ensure its financial stability.

In May 1994, another department was created within the Ministry of Energy to implement the national policy for the development and management of electricity and renewable energy. The

economic growth, and the government negotiating additional IPP expansion (2008), as described further in section 4.2.1.

¹²³ This commission comprised of representatives from the Ministry of Energy's National Bureau of Technical Studies and Development, BNETD (Bureau National d'Etudes Techniques et de Développement) and the EECI.

¹²⁴ The FNEE was incorporated as part of the Caisse Autonome d'Amortissement (CAA); a state bank charged with raising foreign currency and the management of the country's foreign debt. The main purposes of the FNEE were to ensure the payment of EECI debt, raise funds for the development of the power sector, and to oversee payments made to the state by CIE. The FNEE was administered by a Managing Committee comprised of officials from the Ministry of Energy, the Ministry of Finance, the CAA, the BNETD, and the EECI, with further representatives from the Ministry of Energy, the BNETD, the EECI, and the CIE forming a technical committee which assisted the Managing Committee on an advisory basis (N'Guessan 2000:41).

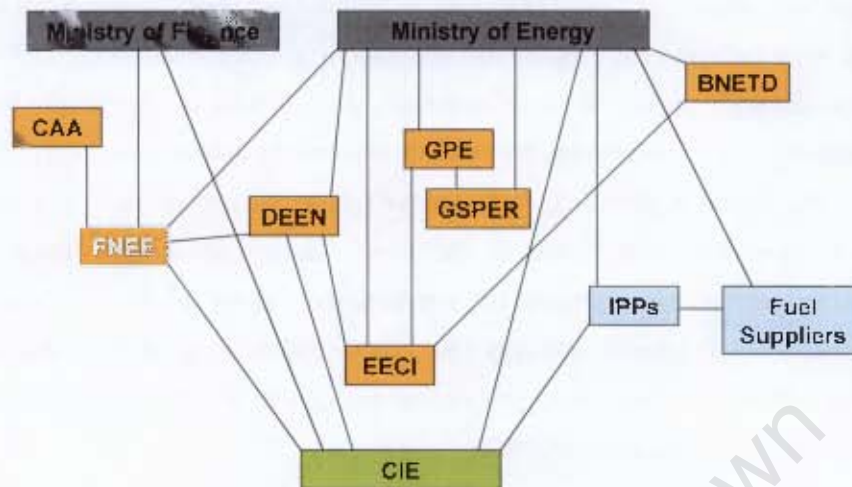
Electricity and Renewable Energy Department, DEEN (la Direction de l'Énergie Électrique et des Énergies Nouvelles), had a number of responsibilities including: compiling and updating the national energy programme; creating and maintaining a database on energy; defining and overseeing a strategy for power sector development; drafting rules of operating in the power sector; overseeing and implementing the various agreements between the government and operators in the sector; contributing to the sector's financial management by assisting in setting tariffs; promoting investment in the power sector; outlining a framework for international cooperation with respect to interconnection of national transmission networks in the West African region; promoting energy conservation and the usage of renewable energies; and ensuring that the national energy programme remains in harmony with environmental protection obligations (N'Guessan 2000:42).

The Ministry of Energy went further in March 1995 by establishing the Special Group for the Rural Electrification Programme, GSPER (Groupe Spéciale Programme Electrification Rurale), whose main objective was to create the best conditions for the country's rural electrification programme. Among other activities, this group was charged with planning and executing the annual activities of the rural electrification programme; assessing bidding documents and contracts; processing contracts; and overseeing payments made to contactors (N'Guessan 2000:42).¹²⁵ It also established the Energy Project Group, GPE (Groupe Projet Énergie), to oversee the financing from the World Bank for power sector projects (including the country's first IPP) and to coordinate the actions of all the technical organisations within the scope covered by the World Bank's IDA loan. By June in that same year, the GPE activities were expanded to include: the evaluation of all problems related to capacity and adequacy of generation and transmission infrastructure; the supervision of issues relating to importation and exportation of electricity; and providing advice to the government on all issues relating to the power sector (2000:43).¹²⁶

¹²⁵ The GSPER comprised of officials from the Ministry of Energy, the Ministry of Finance, the DEEN, the BNEDT, the CIE, the EECL, the government's Public Investment, DIP (Direction Investissements Publics) and Public Markets, DMP (Direction des Marchés Publics) departments, and the Customs office.

¹²⁶ Within six months the GPE had evolved from a temporary structure into a permanent organisation with representation from the Ministry of Energy, the BNEDT, the EECL, the CIE and PETROCI.

Figure 4.3: Structure of the Ivorian Power Sector up until December 1998



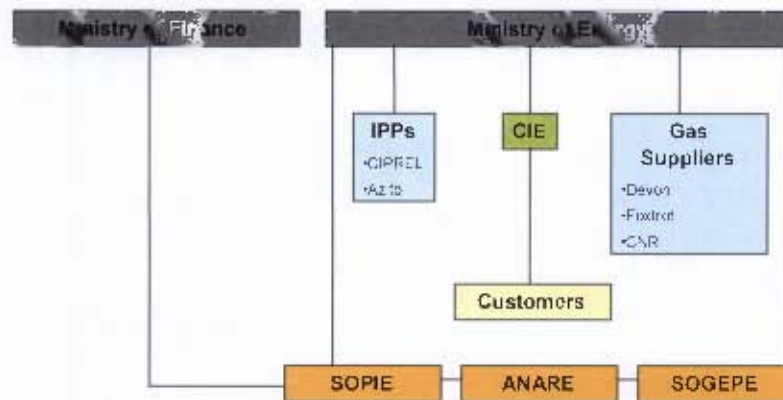
Sources: Vei (1999:18) and N'Guessan (2000:44)

It soon became clear to the state that governmental organisations which had been established to manage the power sector were numerous with overlaps in their executive and governance functions, as illustrated in Figure 4.3. In addition, while there was considerable oversight for power sector functions in theory, it was often confusing as to who accepted overall responsibility for each governance function. N'Guessan (2000:43,48) notes that the professionals who were in charge of and participated in most of these organisations were often the same persons from the Ministry of Energy, the EECI and the BNETD. One observer in the power sector noted that *“each private operator can literally pick the government body with which it is comfortable in order to solve its problem with the lowest possible risk”* (Edjekumhene and Navroz 2002:123).

By 1997, the need for a more streamlined institutional framework in the power sector saw the government making plans for an organisational overhaul,¹²⁷ one that sought to separate the regulatory and oversight functions from the management and operation of the physical assets. On 16 December 1998, the government adopted a new institutional arrangement for the power sector, as depicted in Figure 4.4, which made provision for three state agencies through decree No. 98-725.

¹²⁷ A World Bank financed study was initiated to craft a more suitable institutional arrangement for the power sector.

Figure 4. 4: Structure of the Ivorian Power Sector since December 1998

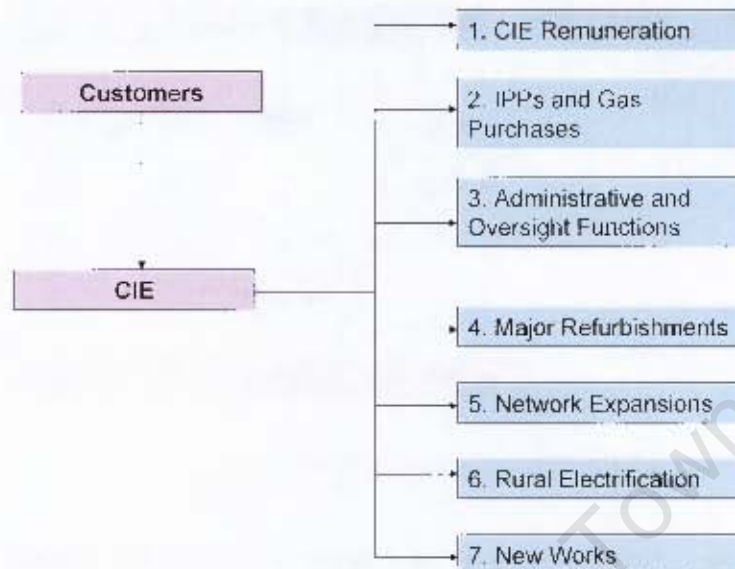


Sources: Veï (1999) and ANARE (2005b)

Firstly, the National Electricity Sector Regulatory Authority, ANARE (Autorité Nationale de Régulation de l'Electricité), was established to regulate the sector, to be an arbitrator between sector participants, and to protect the interests of consumers. Unlike traditional electricity regulators, ANARE has no tariff setting powers and its mandate in terms of price regulation, is limited to the advisory role that it plays to the Ministry of Mines and Energy. Second, an Electricity Sector Asset Management Company, SOGEPE (Société de Gestion du Patrimoine du Secteur de l'Electricité), 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).

At the same time that the new institutional arrangements were ushered in, the state also adopted a new priority payment order for operators in the sector, which was administered by SOGEPE. This favours private operators since they have first claim to funds from the revenues collected by the CIE, as illustrated in Figure 4.5. After the private utility lessee, gas suppliers, and IPPs are paid, funds are allocated to administrative functions in the sector, major plant refurbishments, network expansion, rural electrification and new projects.

Figure 4. 5: Flow of Funds in the Ivorian Power Sector



Source: Simon (2006)

Lastly, an Ivorian Electricity Operations Company, SOPIE (Société d'Opération Ivoirienne d'Electricité), was set up to coordinate power flows in the national grid, including imports and exports to and from neighbouring countries, and to plan for both new generation requirements and capital and major refurbishment projects in the sector (Vei 1999:22).

4.4 Independent Power Producers

The improvements effected in the financial and technical performance of the national utility by SAUR and EDF, after taking over the management in 1990, led the state to consider the same consortium for the development of generation infrastructure. Having had first hand experience of the Ivorian power sector and having made reasonable profits as the country's first private utility operator, SAUR and EDF were prompted to develop Côte d'Ivoire's first IPP. As first espoused through the legislation in 1985 authorising entry of private generators, and in accordance with the preferences and conditions of development finance institutions (most notably, the World Bank), private participation in generation took shape.

4.4.1 Compagnie Ivoirienne de Production d'Electricité (CIPREL)

Formed in 1994, CIPREL started out with the following shareholding: 88 per cent was owned by SAUR International through Valener, a company set up to manage the shares of SAUR (65 per cent) and EDF (35 per cent) (CIPREL pers. com. 2007). The remaining 12 per cent was

held by Agence Française de Développement (AFD)¹²⁸ through its subsidiary, Promotion et Participation pour la Coopération économique (PROPARCO), as well as the International Finance Corporation (IFC) and the West African Development Bank, BOAD (Banque Ouest Africaine de Développement).¹²⁹ Although a selective tender process was administered by EDF and SAUR for the EPC contract, it should be noted that the substation and transmission system expansion as well as Phase II of CIPREL were procured through an international competitive bid (ICB) (IDA 1995; World Bank 1995c).

In 2005, the smaller equity partners (AFD/PROPARCO and IFC) sold their shares in CIPREL along with EDF, and a holding company, Fina Gestion, was created to oversee the equity in CIPREL (CIPREL pers. com. 2007).¹³⁰ At the same time in 2005, SAUR International was dissolved. By 2008, the shares in Fina Gestion were entirely held by the parent company, SAUR Group, with CIPREL's shareholders being Fina Gestion (98 per cent) and BOAD (2 per cent).

The plant comprises four open cycle gas turbines with a combined capacity of 210MW. Three of the gas turbines have a capacity of 33MW each and were commissioned in March 1995.¹³¹ The fourth gas turbine has a capacity of 111MW and was commissioned in June 1997 (CIPREL 2006).¹³² The plant runs on natural gas, which may be provided by one of three gas suppliers (detailed in section 2.3), and, as a backup, may also run on heavy vacuum oil (HVO) or distillate diesel oil (DDO). The plant initially used liquid fuel when it was first commissioned until the gas infrastructure was developed in November 1995 (CIPREL pers. com. 2007). The plant has performed well; since its commercial operation date (COD), its availability has been approximately 95 per cent (CIPREL pers. com. 2007).

¹²⁸ Formerly Caisse Française de Développement (CFD).

¹²⁹ Established in November 1973 and headquartered in Lomé, Togo, BOAD is a development finance institution of the West African Economic and Monetary Union, UEMOA (Union Economique et Monétaire Ouest Africaine).

¹³⁰ Although it offloaded its shareholding position, EDF is still involved in CIPREL in a technical capacity.

¹³¹ The plant was officially inaugurated on April 27th 1995.

¹³² General Electric (GE) is the Original Equipment Manufacturer (OEM) of the four turbines and the company uses GE, Alstom and other OEMs for specialised maintenance. General maintenance is normally subcontracted to local Ivorian companies, viz. Friedlander, Pictor and even CIE (CIPREL, 2006).

a) Project Financing and Incentives

CIPREL was initially built in two phases (with plans for two subsequent phases by 2008). The debt equity ratio at the end of the first phase was 75:25, with debt arranged by the IFC and BOAD.¹³³ By the end of the second phase, the ratio moved to 86:14. For the second phase, the World Bank extended an IDA low-interest loan to the Government of Côte d'Ivoire which it, in turn, lent to CIPREL (CIPREL 2007, pers. comm., 29 March). The on-lending duration term of 17 years means that the maturity of the US\$50m loan coincides with end of the concession term.¹³⁴ The agreement also contains a five year grace period as a contingency to allow for the debt service payment of CIPREL's first phase, which had an amortization period of 10 years (World Bank 1995c:16). As an extra security cushion for the lenders to CIPREL, a six month equivalent of debt service payments were to be held in an off-shore escrow facility (World Bank 1995c).

The project was exempt from all taxes and import duties on equipment. In addition, a tax holiday was granted to CIPREL over a five year phase-out period (World Bank 1995c). By year-six, CIPREL was expected to pay the full tax at the company rate (of 27 per cent). The VAT exemptions on plant equipment and the five year income tax holiday went a long way in making the terms of the deal sufficiently attractive to engage investors.

b) The Power Purchase Agreement

The PPA is rather simple in that it is not linked to a minimum availability as has been the custom in other African IPPs (as was the case in Ghana, Morocco and Tunisia). The arrangement comprises a take-or-pay contract for 1410GWh of power per annum (CIPREL, 2006). In accordance with the agreement, CIPREL is obliged to supply a minimum of 1410GWh a year, but may be asked by the state to increase this amount to 1460GWh a year (Diaw 2004). Payment of the additional power is invoiced at 8 per cent of its nominal value for the first 48GWh and 38 per cent for that over and above the additional 48GWh (CIPREL 2007, pers. comm., 29 March). The contract duration is 19 years and transfer is expected in August 2013 in accordance with the Build Own Operate Transfer (BOOT) agreement. After ten years of operation, the state has the right to buy back CIPREL (World Bank 1995c).

¹³³ This loan was in the form of an US\$79.66 million IDA loan with a maturity of 40 years and a ten-year grace period. US\$50 million would be lent to the CIPREL project and the remaining US\$79.66 million would remain with the government to fund the complementary sector investments and the institutional building components of the project (World Bank 1995c).

¹³⁴ The loan attracts 8 per cent interest per year (World Bank 1995c:16).

Compensation for the assets, the foregone dividends and the take-over of the remaining debt would be included in a negotiated agreement, were the state to exercise this option.

Despite CIE being the physical off-taker of the actual power generated, the contractual agreements are between the Government of Côte d'Ivoire and CIPREL for purchased power. Hence, as far as CIPREL is concerned, it is the government that is the customer in terms of financial and contractual matters.¹³⁵

4.4.2 Azito Energie

Unlike the country's first IPP, Azito was initiated under an international competitive bid launched in October 1996. This occurred at a time when growth in electricity demand was more than 7 per cent per annum. In June 1997, after the bid adjudication process was complete, Azito was awarded to a consortium of five firms, which formed three shareholdings companies to share the equity in the project, as described below (Nandjee 2006). The plant consists of two 147MW gas turbines operated in an open cycle mode. At the project's inception, it was planned that the plant would include a combined cycle unit composed of two heat recovery boilers and a steam turbine with a condenser. To date, however, the steam cycle has not been realised.¹³⁶ Project agreements were signed by July 1998 and construction started immediately although the final financial closure occurred only in January 1999 (Project Finance and Guarantees 1999). Commercial operations started in February 2000.

a) Project Stakeholders and Financing

The winning consortium of the bid consisted of Cinergy (a holding company comprising ABB and EDF), Industrial Promotion Services West Africa (IPS) and the Commonwealth Development Corporation (CDC). Initially, CDC was a lender to the project with a debt-to-equity swap option, which was exercised in 2002 (Azito pers. com. 2007).

¹³⁵ The mandate of CIE is limited to managing the utility, distributing power and collecting revenues; hence, it is not in a position to undertake any long-term financial and contractual commitments on its balance sheet.

¹³⁶ From the time of the coup in December 1999, discussions on the completion of the steam phase of Azito were suspended.

The shareholding is as follows:

- Cinergy Holding Company (EDF and ABB)¹³⁷ 65.7%
- Azito Energie Holding (Aga Khan and IPS West Africa)¹³⁸ 23.1%
- CDC Globeleq¹³⁹ 11.2%

The US\$45m equity invested by the shareholders represented approximately 20 per cent of the total project cost, which amounted to US\$223m for the plant and associated transmission infrastructure.¹⁴⁰ ABB was the EPC contractor to the project and EDF and ABB the operators of the plant.

The lenders to the project were as follows:

Senior Debt

- IFC A loan¹⁴¹ US\$32m 14 years maturity
- IFC B loan US\$30m 10 years maturity
- Commercial Banks US\$30m 12 years maturity
- CDC Club US\$48m 12 years maturity

¹³⁷ Although EDF and Alstom (one of the three shortlisted consortia) lost the bid, EDF was still included in the final shareholding after high level political negotiations (Azito pers. com. 2007). At the time, EDF had undertaken an aggressive strategy to expand its operations outside of Europe and had invested in power developments in Africa, Asia and Latin America (Amuku 2002).

¹³⁸ Active in Côte d'Ivoire for over 30 years, IPS West Africa's investment in Azito was, however, its first in the country's power sector (AKDN 2007; Azito pers. com. 2007). Furthermore, although owned by Aga Khan Fund for Economic Development (AKFED), IPS West Africa and AKFED each hold separate shares in the Ivorian Azito Energie Holding Company, 69 per cent and 31 per cent, respectively, with the Holding Company in turn being a 23 per cent shareholder in Azito (Azito 2004).

¹³⁹ Most of CDC's equity shares in projects were replaced by Globeleq, which was spun off from the CDC Group in 2002 and established to invest in power projects in Africa, the Americas and Asia. It should be noted, however, that Globeleq remains entirely owned by CDC.

¹⁴⁰ The shareholders also committed US\$17m to the project as a contingency measure (Project Finance and Guarantees, 1999).

¹⁴¹ IFC A loan refers to IFC's own account, whereas IFC B loan refers to an IFC syndicated loan.

Subordinated debt

- IFC Fixed US\$4m
- IFC Convertible US\$4m
- CDC Club US\$6m
- CDC Fixed US\$6m

The CDC Club senior debt was funded by a number of bilateral and multilateral institutions including the African Development Bank, the Netherlands Development Finance Company (FMO) and the German Investment and Development Company (DEG). In addition to the equity and debt funding, US\$18m from operations (after the first gas turbine was commissioned) went towards financing the project (Project Finance and Guarantees 1999).

The amount of US\$30m in loans from commercial banks was underwritten by an IDA Partial Risk Guarantee (PRG) and syndicated by Société Générale of France (Gaba, 2001).¹⁴² The PRG payment obligations include capacity and termination payments for breach of contract of the Concession Agreement including the Power Purchase Agreement and the Gas Supply Agreement; changes in law, political *force majeure* events and natural *force majeure* events (relating to the gas pipeline and the transmission facility). In parallel, the Government of Côte d'Ivoire has provided a counter guarantee to IDA through which the latter would be indemnified in the event of a call on the IDA Guarantee, thereby making the Ivorian government ultimately responsible for its own performance. The lenders also received Letters of Comfort from the Government of Côte d'Ivoire (Gaba 2001).

b) Power Purchase Agreement and Project Incentives

The PPA is on a take-or-pay basis and consists of a capacity charge (± 80 per cent) and an energy charge (± 20 per cent). The contract is for 24 years, including the first two years of construction. Unlike CIPREL where a specific volume of power is contracted annually, Azito is required to adhere to a guaranteed minimum availability factor of 87.6 per cent (Azito pers. com., 2007). According to the agreement, the first 13 years will be charged at 18 CFA

¹⁴² IDA was brought on board when the government extended the scope of the financing to include the transmission infrastructure and requested the sponsors to finance the additional cost. Azito was the first power project in Sub-Saharan Africa to borrow privately from a syndicate of commercial banks (World Bank 2003a:29).

franc/kWh ($\pm 2.7\text{€}$ cents per kWh) and the following 11 years will attract a charge of 11 CFA franc/kWh ($\pm 1.7\text{€}$ cents per kWh). The average charge (excluding fuel) is, therefore, around 15 CFA franc/kWh (2.2€ cents per kWh).

Like CIPREL, Azito was exempted from all taxes and import duties on the equipment for the plant in accordance with the country's investment incentive framework (Simon 2006). In accordance with the BOOT agreement, the plant will be transferred to the state after 24 years of operation (in 2022). The economic rate of return on the project was estimated to be in the order of 20 per cent for a low growth scenario (World Bank 1998), which made the project attractive from an investor perspective.

c) Fuel and Project Performance

As described in Section 4.2.3, Azito runs on natural gas with the government assuming responsibility for gas provision, as it does for CIPREL. A back-up supply of distillate diesel oil is kept on site (sufficient for five days). Unlike CIPREL, which had to wait for nearly a year for the gas infrastructure to be completely developed, Azito utilised domestic gas from the first day of operations. As of yet, no problems have been encountered with regard to fuel supply for the plant.

Despite civil conflict coinciding with the timing of COD and prompting several contractors to flee the country, Azito was completed within budget and within a relatively short project time-table. Shortly after commissioning, Azito supplied more than 40 per cent of the country's domestic demand. Even in the midst of political turmoil, the project continued to operate and all charges have been paid to date in spite of foreign exchange transfer restrictions being imposed for a period of one week five days after President Bédié's government was overthrown (Gaba 2001).¹⁴³

4.5 An Analysis of Ivorian Hybrid Power Arrangements

Cote d'Ivoire is a rare example of a power sector in Sub-Saharan Africa where there are no traditional SOE utilities responsible for the day to day operation of the electricity system. IPPs account for nearly two thirds of production and the remainder is provided by CIE, the management operator of the national utility. Although there is some uncertainty about the

¹⁴³ A temporary debt moratorium was also announced the second week after the coup d'état, but was lifted one week later (Gaba 2001).

future energy policy. largely as a result of the country's political uncertainty, there is a clear sense that the investment environment that predominated in the 1990s and the policy and planning frameworks introduced during this time have gone a long way in contributing to the country having sufficient electricity resources. The factors contributing to these outcomes are explored in the following sections.

4.5.1 Evolving Power Sector Reforms and Resulting Hybrid Arrangement

Like many other African countries that have embarked on power sector reforms, Côte d'Ivoire's reform trajectory was prompted by both internal and external forces. These include the deteriorating financial and technical performance of the national utility and pressure from development finance institutions, such as the World Bank. The drought that compounded the problems of the sector forced the government to institute reforms.¹⁴⁴

These forces also informed the government's electricity policy framework. Thermal power plants and local gas resources were developed to curb over-reliance on hydro and expensive imported fuels. Through the Electric Energy Act 85-583 of 1985, the power sector was legally obligated to maintain financial equilibrium (i.e. for revenues to cover costs). Furthermore, due to the financial constraints of the state and the national utility, the private sector was invited to develop power plants. Finally, an explicit policy was developed to make Cote d'Ivoire an electricity hub for the region (Ministry of Mines and Energy pers. com. 2007).

Unlike the formation of other hybrid markets described in this thesis, the Ivorian ESI took a bold step to reduce the state's involvement from an operator in the sector to that of providing oversight and dealing with longer term strategic issues. The introduction of the private management operator depoliticised the daily operations of the utility and paved the way for operational performances to improve. In addition to the lack of previous experience in crafting a new institutional framework for the sector, the speed at which the decision to invite private sector participation was taken and the resulting entry of the private operator (within six months), gave policy makers and administrators little time to deliberate the mechanics of how the sector as a whole would and could operate to meet the objectives of the reforms.

¹⁴⁴ The impact of the drought was multi-fold. First, with drought affecting the country's agricultural outputs, Cote d'Ivoire saw a significant decline in foreign currency earnings. Drought also impacted the largely hydro-dependent electricity sector and prompted a move to thermal. This move and the procurement of fuel from international markets further strained the country's balance of payments.

It is, therefore, not surprising that the institutional arrangements created initially in the early 1990s were sub-optimal in terms of improving sector performance. At the time that most power sectors in developing countries were only starting to consider power sector reforms and private participation in infrastructure (PPI), Côte d'Ivoire was well into its second round of power sector institutional reforms to optimise the functioning of the sector and deal with the challenges of securing sufficient and affordable generation capacity.

Nearly two thirds of electricity generated is from two IPPs with long-term PPAs and this percentage is set to increase in the future. The high degree of private sector participation differentiates the Ivorian power sector from others in Africa where IPPs operate only on the fringes and SOEs are responsible for the bulk of electricity supply; and in the Ivorian case the SOE is not an operator in the sector, but only an owner of the assets. This unique organisation of actors in the generation sector allows for an interesting evaluation of hybrid arrangements that impact on attracting investment into generation and securing capacity.

4.5.2 Power Sector Planning

Prior to the reforms introduced in 1990, responsibility for planning resided with the state-owned EECl. This remained the case after the introduction of CIE in 1990 when the role of the EECl was reduced as explained above. The role of sector institutions, including the EECl, continued to evolve as the sector tried to find the optimal institutional framework to meet its objectives. The end result was a simplified institutional framework in the form of the present structure (although, it has to be said, the institutional arrangements are still quite complex and could be further rationalised).

The period between the two rounds of institutional reforms from 1990 to 1998 when the sector was still searching for an optimal institutional arrangement does not appear to have hampered investment in the sector. At the core, the legal framework and tariff structures were deemed adequate to facilitate the required amount of generation investment (until the political coup). The development of CIPREL and Azito during this period suggests that, although institutional coordination could have been compromised, the operation of CIE under a long-term lease agreement and the government's commitment to reforms and PPI gave investors the assurance that the sector was on a positive trajectory.

a) The Planning Context

The planning and project development context has also enjoyed a more favourable environment than was the case in Ghana. Firstly, although structural economic adjustments were in progress and the currency was devalued by half at the time of CIPREL's negotiations (in 1994), investors anticipated that this planned devaluation would stimulate growth in the economy, and that this would impact positively on the power sector. As it turned out, the devaluation of the CFA franc did contribute to a surge in economic growth and a corresponding increase in demand for electricity mainly due to industrial customers supporting export-oriented sectors. After the devaluation, tariffs increased by approximately 20 per cent (Lavigne 1999). Despite a tariff increase in devalued CFA franc terms, revenues to CIE decreased in real terms initially; however, CIE was, eventually able to improve its financial accounts, primarily by revenue gained from exporting power to neighbouring states (Jammal and Jones 2005).¹⁴⁵

Secondly, by the time that the Azito investment was concluded, the country was well on its way to sustaining robust industrial growth, and, hence, there was huge interest from investors in the development of the country's second IPP, despite negative global IPP experiences. Interest in the sector was at such a level that the government was able to change its approach from a negotiated agreement (as was the case with CIPREL), to awarding the contract for the second plant to the lowest bidder after an international competitive bidding process. The positive experience with CIPREL, Africa's first IPP, gave momentum to the country's PPI drive and facilitated the development of the second plant.

Thirdly, due to the fact that the CFA franc is pegged to the Euro (historically through the French franc), Côte d'Ivoire has not experienced the problem of severe local currency devaluation and increases in electricity tariffs linked to the foreign currency earnings of IPPs, as in the case of other African countries (e.g. Egypt and Ghana). Traditionally, inflation and devaluation of local currencies have threatened the income streams for power providers in Sub-Saharan Africa. In contrast, Côte d'Ivoire's inflation is considered relatively low (at approximately 4 per cent in 2007) with the Central Bank of West African States, BCEAO (Banque Centrale des États de l'Afrique de l'Ouest), following a tight monetary policy in UEMOA countries. The currency devaluation occurred before CIPREL started commercial operations, and the PPA took this into consideration in its planning.

¹⁴⁵ Wages, an important input component of the cost of electricity, decreased with the devaluation of the CFA franc (Plane 1999).

Lastly, electricity exports, as noted throughout, have been a mainstay for the sector in the last decade. They have helped mitigate large demand and supply mismatches, especially during the period of civil unrest when national consumption decreased from 86 per cent of national production in 1995 to 70 per cent in 2002 (AfDB/OECD 2004).¹⁴⁶ More specifically, as the construction of Azito was being completed, political events in the country took a turn for the worse. The demand for power, among other things, was dampened, which threatened to choke the estimated income stream that formed the economic basis for the plant. The silver lining for Côte d'Ivoire came in the misfortunes of its neighbours who were experiencing power deficits due to droughts and a general lack of generation capacity. Exports to neighbouring countries, mainly Ghana, which accounted for more than 60 per cent of exported power in 2005, meant that income from electricity generated continued to flow in.

The country's policy to become a major power exporter in the region has contributed to flexible planning strategies since it has allowed the country to develop excess generation capacity without bearing the burden of stranded generation. In this case, should there be delays in the development of future capacity additions, as was the case after the coup d'état, the country will have time to adapt to the new circumstances and develop alternative strategies to develop additional power production facilities, as reserve capacity would take longer to be run down.

b) Regulatory Framework

While the general policy and planning frameworks have contributed to positive outcomes, it would seem that the role of the independent regulator, ANARE, has not been significant. Following the French legal tradition, regulation has, in effect, been embedded in contracts, for example, in the lease agreement with the private operator, as well as in the PPA contracts with the IPPs.

Since ANARE became operational only after the IPP deals had been signed, it had no role in the licensing of the IPPs or approval of PPAs. Furthermore, apart from acting in an advisory capacity to the state, the energy regulator has no legal mandate to effect substantial changes to contracts with IPPs or even to regulate prices – usually a core function of regulators. It appears unlikely that ANARE will be given any opportunity to impact the terms of the

¹⁴⁶ It should be noted that national production in 1995 did not include the Azito IPP since this was commissioned in 1999.

agreements in the next round of negotiations with IPPs (ANARE pers.com. 2007).¹⁴⁷ While it may be argued that IPPs are subject to less regulatory risk in this context and that this bodes well for attracting investment, it is often argued that in the absence of an active, empowered and independent regulator, IPPs may mean that the possibility of political interference is greater. In the case of Côte d'Ivoire, the extent to which political interference could have been experienced was perhaps moderated by the legal requirements for financial equilibrium in the sector as far as tariff setting is concerned. In addition, the presence of a private utility operator whose incentives are motivated by performance rather than by political considerations and which ultimately has to collect sufficient revenues to cover the charges from IPPs are important factors. Finally, IPPs are regulated by their contracts with the Ministry of Energy. These are fixed for the duration of the PPA term making the need for any ongoing regulation after agreements have been reached largely unnecessary, unless there is a need for mediating disputes.

c) Benefits of Contracting Out the Utility Function

Although Cote d'Ivoire has seen a marked change in its ESI, primarily via IPPs but also through the private management of its utility, at the end of 2008, there was no official long-term strategy for the management of the electricity utility beyond the expiry of the current contract in 2020. Undecided is whether the long-term lease agreement with CIE will continue beyond the expiry date or whether the state will resume responsibility for the operations of the national utility (Ministry of Mines and Energy pers. com. 2007).

In many respects, the lease agreement for management of the utility has been beneficial in that it has facilitated the introduction of IPPs, which, in turn, have been critical in ensuring security of supply for Côte d'Ivoire and providing increased energy availability for the region. Without CIE at the helm during this process, it is possible that new generation could have been seriously delayed or not built at all (Jammal and Jones 2005). It is also widely acknowledged that the management company contributed to the utility's financial turnaround. For instance, there has been a marked improvement in the utility's technical and financial performance since private participation began. Billing recovery for collections

¹⁴⁷ This may be due to the French legal framework for public infrastructure. French (civil) law differs from common law with regard to transactions for public services. Public service contracts under French law constitute a guarantee of public service commitments by the state, even within the context of opening up markets such as electricity. Thus, from a strictly legal perspective, the dominant role that the state plays is justified as the notion of public service is the principal criterion (Fournier 2005; ESI Africa 2006).

increased from 70 per cent before CIE was instituted in 1990 to 98 per cent in 2004 (ANARE 2005a). CIE has put the utility on an improved financial footing; this has helped improve confidence in the sector and the attraction of private capital for generation projects.

A question to be considered is: “Over the longer-term, has the private operator outlived its usefulness or is such an operator necessary to maintain solvency and efficiency?” For the foreseeable future, the management of the utility under the lease agreement will probably help keep the sector out of the red and bolster support for investments by IPPs, which will continue to play an important role in bringing in additional capacity, since neither the state nor the utility has sufficient funds to invest in additional generation capacity.¹⁴⁸ Stakeholders in the Ivorian power sector interviewed for this thesis have indicated that the decision to sign another 15 year contract with the CIE in 2005 may have been the most prudent, given the political uncertainty and diminishing electricity generating reserves. Continuation of the contract may have restored investment confidence, not only in the electricity sector, but also in other sectors to which the CIE has been a reliable supplier and distributor of power.

4.5.3 Generation Procurement

The same departments that had been responsible for generation procurement prior to the reorganisation of the sector in 1990 remained with the EECl when the new operator assumed operations in the form of the CIE. Since the CIE had no mandate or contractual responsibility to ensure additional capital expansions in generation and the rest of the power sector, planning and procurement remained roles of the state. During the second round of institutional reforms in 1998, the same departments were transferred to SOPIE (and SOGEPE) and continued their respective functions under the new institutional framework.

SOPIE, which reports to both the Ministry of Energy, has as its prime mission the responsibility to co-ordinate and balance the supply and demand of electricity. It is also required to manage financial aspects of public sector investment that uses state funds, such as the country’s rural electrification programme. For private sector projects such as IPPs, SOPIE

¹⁴⁸ At the inception of the country’s IPP programme, it was intended that the government would institute a tariff adjustment framework that would cover 20 per cent financing of the investment programme over and above the operating costs and debt service (World Bank 1995c:23). This would translate to an 8 per cent rate of return on assets for the power sector. Up until December 1999, this was the case. Since the coup in 1999, however, this policy has not been strictly followed (Ministry of Mines and Energy pers. com. 2007).

advertises present and future projects through various media (including its web portal) to inform private investors of opportunities for investment in the sector, and ensure transparency in investment and procurement processes. Both SOPIE and SOGEPE, another agency created as part of ongoing reforms, evolved as departments within the former EECL, taking on responsibility for almost all aspects of financial, legal and technical planning. This meant that the planning and generation procurement functions enjoyed a measure of continuity throughout the reform process, and was not left unchecked as was experienced in the power sector in Ghana.

Having worked closely with institutions such as the World Bank and other development finance institutions, Cote d'Ivoire had familiarised itself with lending conditions (such as competitive bidding) which shaped its tendering and procurement processes for infrastructure investment. It had been assisted with procurement support since the country was obliged to apply internationally accepted procurement and contracting processes for infrastructure development projects which benefited from World Bank financial support.¹⁴⁹ The two IPPs also benefited from other incentives from the World Bank such as the low interest loan that was extended for CIPREL and translated into a lower cost of capital for the project, and the PRG that was underwritten by the World Bank and served as a catalyst for securing additional commercial debt for Azito.

A further example of how World Bank financial support influenced procurement was with the acquisition of equipment for CIPREL. Even though the CIPREL IPP was a negotiated deal between the government and the EDF / SAUR consortium, World Bank procedures still called

¹⁴⁹ Côte d'Ivoire has a long history of working with the Bretton Woods institutions and, in general, adopting their policies. The country had known private participation in its infrastructure industries for a number of decades and was thus receptive to the idea of private investors if accompanied by an improvement in services without unnecessarily increasing costs significantly. In addition, since 1990, the country had privatised 44 of the 61 entities earmarked for privatisation (NIGC 2001). The country's first leader since independence, President Félix Houphouët-Boigny, adopted a liberal economic system to gain the confidence of foreign investors, most notably, French investors, some of whom had been present before Côte d'Ivoire's independence. In addition to the country being relatively friendly to foreign investment, the head of state during the time that the two IPPs were developed (1993-1999), President Aimé Henri Konan Bédié, who was instrumental in shaping sector privatisation policies, has also had a long history with the Bretton Woods institutions. While Minister of Finance of the republic, he became the first chairman of the IMF and World Bank's Joint Development Committee from 1974 to 1976 and worked as special advisor to the World Bank's IFC from 1978 to 1980 (PDCI-RDA 2005).

for the EPC contract to be put out on open tender. To this end, gas turbines with a range of 75-105MW for CIPREL were chosen to allow the maximum number of manufacturers to participate in the bidding process (World Bank 1995d:19). It was anticipated that this would put downward pressure on OEM tenders to supply the main plant hardware for the power station (1995d:15).¹⁵⁰

4.5.4 Contracting Arrangements

Contracting arrangements for privately generated power are between the Ministry of Energy and IPP sponsors; the CIE as utility operator does not enter into any contracts with private generators. The payment priority order for suppliers to the ESI also favours private investors since they have first claim to funds from the revenues collected by the CIE. After the private utility lessee, gas suppliers and IPPs are the first to receive revenues collected from electricity sales. Thereafter, funds are allocated to administrative functions, major plant refurbishments, network expansion, rural electrification and new projects. The general contracting framework, therefore, favours private investment in generation since it gives greater assurances to investors and lenders to privately financed generation projects and, in so doing, assists in securing sufficient generation capacity in Côte d'Ivoire. This is one of the factors that has contributed to current IPPs having expressed their willingness to expand their interests in the generation sector despite the political turmoil that erupted in the country after the coup d'état and which resulted in revenue losses for the sector.

In addition to the security from the priority payment order in the sector, for Azito, the commercial lenders are insured against default of payments through an IDA Partial Risk Guarantee. Commercial funds were more easily mobilised towards completion of the project due to the presence of such a guarantee. This and government counter guarantees assisted in lowering the cost of capital, which resulted in more affordable power for consumers (UNDP 2003). The inclusion of large prominent multilateral and bilateral lenders such as CDC, FMO, DEG, IFC and the World Bank extended an added assurance to investors and commercial banks.

¹⁵⁰ The technology choice was also based on anticipation of domestic gas, which ultimately has gone a long way in keeping power prices down.

4.6 Conclusion

This chapter has traced a number of exogenous events before and during the period of Côte d'Ivoire's ESI reforms, namely, severe droughts, significant currency devaluation immediately pre-IPPs, political unrest, and suspension of a large part of revenue from power sales for an extended period due to the civil war. Despite these events, interest in the country's power sector has not been quelled - with both the existing IPPs keen to expand their interest in the generation sector. Few countries' power sectors would have sustained all these exogenous shocks. Why has Côte d'Ivoire fared so well?

The overriding policy objective that formed part of the reforms in the 1990s was to ensure financial equilibrium in the sector. This was legislated in a decree and, by law, institutional stakeholders have an obligation to meet this fundamental objective. It may be argued that a stable currency that has been pegged to the French franc since January 1994 and to the euro since 2002 means that revenue assurances in terms of exchange rate risks are more robust than has been typical of most Sub-Saharan African IPPs, as well as in other developing regions. A more coherent power sector planning approach after the droughts of the 1980s has resulted in the country achieving an optimal mix of hydro and thermal power sources, sufficient power to supply itself and assist its neighbours during generation crises (thereby generating further revenue), and giving it greater flexibility in its future generation planning.¹⁵¹

Having the state removed from the daily operations in the power sector means that it can focus more clearly on long-term and strategic issues such as power sector planning, and fulfill its governance role. SOPIE's main objective is to ensure that adequate electricity is available in the country and that its responsibilities for planning and procurement are fulfilled. SOPIE and SOGEPE understand their roles in ensuring adequate generation and have the mandates and authorisations to execute this responsibility, benefiting from the legal framework that supports them in their mission. Having these two institutions independent of the national utility assists in avoiding conflicts of interest in the single buyer market framework and helps to create the transparency and certainty for potential investors, thereby facilitating new private investment in generation.

¹⁵¹ The presence of domestic gas has helped keep power prices down relative to countries that have no domestic fuel resources and has helped the country to be among the least costly providers of electricity in the region (AfDB/OECD 2004:115).

CHAPTER 5

POWER SECTOR REFORM IN MOROCCO

Although Morocco has seen a significant increase in private participation in its ESI at the generation level (and also at the distribution level) with IPPs accounting for more than two thirds of domestic production, the country's experience in attracting investment into generation has been mixed. Between 1989, when reforms were initiated, and 2005, Morocco was successful in reducing its domestic production shortage and attracting IPPs. Since 2005, when the country's third IPP was commissioned, however, Morocco has encountered a number of problems with respect to the development of additional generation plants. Generation supply side planning and commissioning has been out of sync with demand side increases during the period of executing the country's aggressive rural electrification programme, which substantially boosted demand for electricity. Despite not adding sufficient amounts of generation production to the national grid, regional integration through transmission links with Spain, and to a lesser extent with Algeria, have assisted in sourcing the much needed power imports to make up for the shortage of domestic electricity production.

Problems around fuel security for one of the country's proposed power stations and environmental concerns over pollutants in another anticipated plant have stifled the development of new generation capacity resulting in the country facing a crisis if critical remedial actions are not implemented as a matter of urgency. Planning, therefore, has not adequately anticipated risks related to the development of these projects. Furthermore, since 2004, the national utility has experienced financial troubles largely due to insufficient tariff increases over the years to accommodate the increasing costs of power production. This has impacted on the attractiveness of Morocco as an investment destination for IPPs. In the absence of credible governance institutions to ensure financial sustainability and sufficient planning oversight, it is unlikely that the objective of attracting investment and commissioning adequate generation in a timely manner will be attained or sustained.

5.1 Introduction

Prior to structural reforms in the 1980s, the Kingdom of Morocco financed infrastructure investments, including electricity, mainly through concessionary loans from multilateral institutions. Imprudent fiscal practices, together with a series of currency devaluations, led Morocco into a spiral of debt. By the mid 1980s, external debt exceeded the country's annual GDP, and much of the country's revenue went toward servicing this debt. Under the guidance of the World Bank and the International Monetary Fund, Morocco turned to project finance, as part of a broader structural adjustment programme, to procure the much needed new electricity generation capacity for the country's development. The goal was to reduce government debt and increase overall economic growth, primarily by limiting government spending and reducing the state's involvement in the economy. Privatisation of existing state-owned enterprises featured prominently on the reform agenda, together with liberalisation of foreign trade and tariffs, opening the economy to new foreign investment and overhauling the country's fiscal system. In 1989, the requisite legislation was passed through law no.39-89 to allow the transfer of public assets to the private sector, with the aim of raising funds to pay off government loans, transferring skills and technology, and achieving efficiency gains.¹⁵²

Private participation in the ESI represented one component of the larger economic reform programme and included the following specific aims. Firstly, it was expected to free up government funds to service more pressing areas of social spending as well as aid in relieving the state's debt burden from power sector investments. The national utility could then focus on rolling out the necessary infrastructure to take power to rural areas where, at the start of power sector reforms in 1994, only 17 per cent of the rural population had access to electricity. Secondly, in conjunction with a broader liberalisation programme including tax reductions and efficiency improvements, it was anticipated that privatisation would decrease the cost of power, thereby making the country as a whole more competitive and attractive to investors. This, in turn, would help facilitate other development infrastructure investment programmes rolled out by government. Private participation in generation was seen as among the first steps in achieving these goals.

¹⁵² Between 1993 and 2003, 66 of the 114 entities that were initially earmarked for privatisation were transferred to the private sector, which resulted in an additional MAD54 billion in income for the state (Ministry of Finance and Privatisation 2004:9). Based on an annualised averaged exchange rate, this translates into approximately US\$5.54billion.

Between 1994 and 2008, three IPPs have been commissioned in Morocco. An examination of Morocco's experience in attracting investment in this context is, therefore, particularly important. In addition, as these projects have been noted for their successes, they may hold wider lessons for the development of future IPPs. As is noted in this chapter, the three projects are very different in nature. Through the first project, the Jorf Lasfar Energy Company (JLEC) and presently Africa's largest IPP, the country placed nearly two thirds of Morocco's electricity production in the hands of private producers. The second project, Compagnie Eolienne de Detroit (CED), which brought about further diversification of the electricity production mix by harnessing Morocco's wind energy potential, is a record setter in that it represents the first wind farm in Africa that is entirely privately financed. Energie Electrique de Tahaddart (EET), the third IPP, served to introduce the first combined cycle gas plant to Morocco, and is fuelled from the pipeline that delivers Algerian gas to Spain. Another outstanding feature of EET is that the majority of project financing was sourced from local Moroccan banks. Among the key elements that explain project successes is that the Moroccan dirham (MAD) has remained relatively stable in a low inflation environment since the inception of the contracts, and, in the case of EET, charges are significantly shielded from foreign currency risks.

Although Morocco was able to reduce its deficit in electricity generation (which was made up for by imports) up until 2005 when EET was developed, more recent delays in planning and developing additional generation capacity have resulted in the country increasing its dependence on power imports, which constituted more than 9 per cent of demand in 2007.

The chapter is structured into three parts. Following this introduction, the next section provides a description of the electricity supply industry in Morocco and the reforms that have taken place in this sector. The third section describes the three independent power projects that have been supplying power to the national grid since power sector reform started and the contractual agreements that have been reached by the various stakeholders. The last section discusses some of the key elements that affected reform outcomes and played a part in the country's experiences attracting investment in generation.

The information presented in this chapter draws on literature searches and detailed interviews with key stakeholders in the Moroccan ESI. Interviews, including written queries and responses, were conducted with several industry stakeholders in Morocco throughout 2006. Interviews were followed by email correspondence to clarify discussion points through 2008. Stakeholder interviews included representatives from the Office Nationale de l'Electricité (ONE), Jorf Lasfar Energy Company (JLEC), Compagnie Eolienne de Detroit (CED), La

Compagnie du Vent (a company established to perform maintenance on CED plant) and Energie Electrique de Tabaddart (EET). Throughout the text, stakeholders have not been identified by name but solely by their organisational affiliation.

5.2 The Moroccan Electricity Supply Industry

This section provides a description of the history of the electricity supply industry in Morocco. It gives an overview of the reforms that have taken place to date and outlines the evolution of the generation, transmission and distribution sub-sectors.

5.2.1 Evolution of the Power Sector

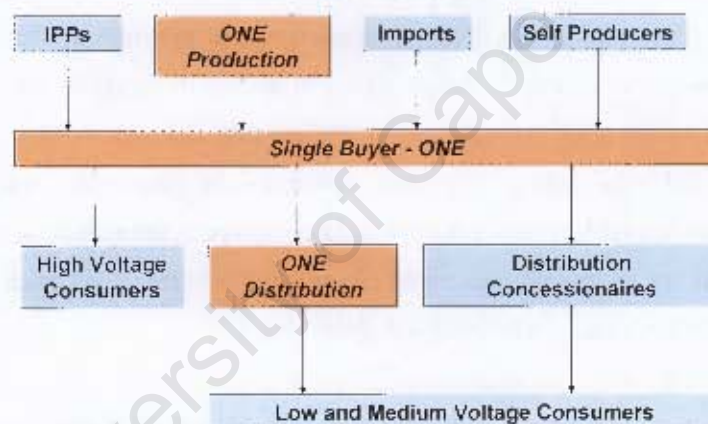
In 1923, Energie Electrique du Maroc (EEM), a private limited liability company, was created to render the public service of electricity generation and distribution in Morocco (Debbah 2006). At the time of the country's independence in March 1956, unlike the experiences in many other African countries, the state did not effect any major changes in the electricity industry with EEM maintaining a private monopoly in generation, transmission and distribution of electricity. More than seven years later, however, the state took control of what was perceived to be a strategic economic sector and created the Office Nationale de l'Electricité (ONE) by decree 1-63-226 of 5 August 1963.

A number of challenges hampered advancement of the country's energy sector in the two decades that followed, including the country's dependence on foreign commercial primary energy and its economic difficulties. By the early 1980s, calls for improved sector coordination and planning forced a re-evaluation of investment priorities in the energy sector and underscored the need to strengthen planning at the enterprise and central government levels (World Bank 1984). In the decade that followed, although there was an increased focus on technical planning at a utility level, the country remained plagued by inadequate domestic electricity reserves, inadequate finance for generation investment, frequent load shedding, and insufficient access to electricity by the general population (especially in rural areas).¹⁵³ Until

¹⁵³ In 1981, a severe drought strained the already difficult circumstances of the power sector and country as a whole. From this time through to 1984, 85 per cent of the commercial energy consumed in Morocco was derived from imported oil which consumed roughly 40 per cent of the country's total export earnings (World Bank 1984:13). In addition, the average price at which electricity was sold on to consumers was only 60 to 70 per cent of the estimated cost of electricity (World Bank 1984:19). The uneconomic tariffs charged also contributed to the rapid growth in consumption; hence, the national

1994, ONE had been solely responsible for production, transmission and distribution of electricity in Morocco.¹⁵¹ Primarily due to financial difficulties in ONE, a shortage of electricity production, and the need to control public spending, the government undertook a major organisational overhaul of the utility and invited the private sector to develop large scale power projects (EIA 2004a:5). These actions helped ONE regain profitability in 1995, and in the decade that followed (1995-2005) private operators increasingly dominated the generation and distribution sectors in the ESL. Although private participation in the sector is prevalent at the generation and distribution levels, by 2008, ONE is still a state-owned company, overseen by the Ministry of Mines and Energy. Figure 5.1 depicts the layout of the industry organisation as at 2008.

Figure 5. 1: Organisation of Moroccan Electricity Supply Industry



Sources: ONE (2006b), Allen and Overy (2007:18)

In 1995, with the objective of further improving the operation and competitiveness of the ESL, the government planned to institute a regulatory system to govern the remaining liberalisation of the sector (Louali 2004:9). After having studied the regulatory systems in a number of occident countries, a regulatory framework was tabled for introduction into the sector around 2005 and 2006. Since then, however, little has been done with respect to the implementation of the government's regulatory plan, with the state still assuming the de facto role of

utility was unable to finance the required growth in expansion and neither was the state in a position to assist, with the country's foreign debt peaking at a historical 113 per cent of GDP.

¹⁵¹ Prior to the change introduced in 1994, private self-producers were, however, allowed to generate electricity provided their output remained below 300kW.

regulator.¹⁵⁵ In accordance with the new framework, the sector would be progressively opened to competition, with two customer classes whose criteria are expected to evolve with time. Large users of electricity, particularly those in the high voltage categories, would be able to select their supplier of choice, with prices determined by the market. Customers eligible to choose their supplier would compete in an open market either through an electricity exchange or through bilateral contracts. Non-eligible (smaller) customers would remain in a regulated market with ONE as the exclusive supplier. The regulated market is intended to supply customers, for whom electricity constitutes a basic service, at the low voltage level and this service would be guaranteed by the state. For this reason, it was intended that this market will be supplied mainly by the power stations realised in the framework of a purchase guarantee. All current IPPs in Morocco, therefore, would, operate in this regulated market (Jerjini 2002). Tariffs for the sale of electricity to distributors and final consumers would be regulated and defined by decree by the office of the Prime Minister, taking into account existing contracts for the production and private distribution of electricity.

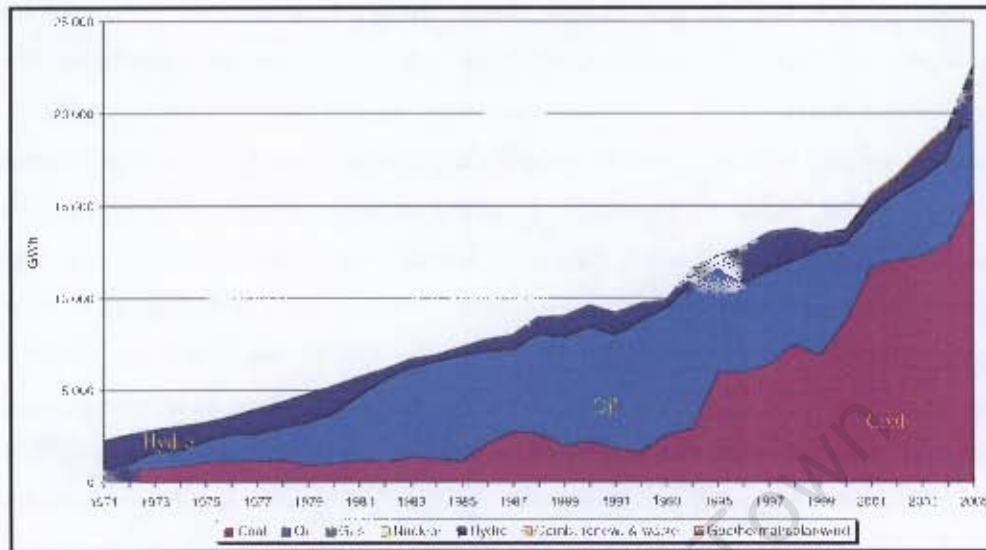
5.2.2 Generation

At the time of Morocco's independence in 1956, there were ten hydroelectric plants (meeting roughly 90 per cent of the country's demand), two coal-fired plants, and two oil-fired plants, which altogether supplied approximately 90 GWh of electricity per year (ONE 2003:23). With demand doubling approximately every ten years, in the two decades that followed, additional plants were brought on line to meet the needs of industrial and domestic consumers; however, with the country's hydro reserves largely exhausted, new capacity was mainly thermal-based.¹⁵⁶ Figure 5.2 shows the evolution of the country's electricity generation mix.

¹⁵⁵ Liberalisation of the generation and distribution sectors are now only scheduled for 2012 (Debbah 2006:89). Although the new regulatory system was planned to be introduced in 2005/2006, it is not clear at this stage whether the regulatory processes and functions will be under the tutelage of the Ministry of Mines and Energy or if an independent institution will be formed to fulfil this function. Given the ongoing regional integration, the creation of a Mediterranean-Maghreb power market by 2010, and the on-going liberalisation of the sector, the creation of a more independent institution may be required (GRTE 2006; Hall 2008).

¹⁵⁶ Although the 450MW Afouer pump storage hydro scheme has been commissioned since then, it has a net negative energy output.

Figure 5. 2: Moroccan Electricity Generation by Fuel Source: 1971 to 2005.



Source: International Energy Agency (2007c)

Despite its challenges, the Moroccan ESI functioned relatively well up until the early 1980s. At that time, a combination of droughts, an increase in electricity demand, and lack of infrastructure financing began to strain the electricity system. With a system dependent on hydro for a significant part of its production, the droughts of 1983-1985, and again in 1992-1993, required increased usage of thermal plants. This led to minimal maintenance being conducted on the equipment and, in turn, an increase in incidences (such as generator trips) on these units. In addition to the unscheduled outages, demand was growing at a rapid rate at the time, reaching around 8 per cent growth in 1992 (Bouyad 2001:7). As a result, load shedding became a common occurrence in Morocco. With financing hard to come by, new power projects were delayed. Eventually, emergency gas turbines were ordered and installed for power generation, but not before the impact of the crisis had made a significant impact on the daily lives of most Moroccans.

The electricity crisis in the mid 1980s and early 1990s prompted policy makers to rethink Morocco's dependence on hydropower. Coal, at the time accounting for only 8 per cent of production, was considered among the best alternatives to help diversify the production mix.¹⁵⁷

¹⁵⁷ Additional coal could be sourced from the Jerada coalfield in northeast Morocco, which was discovered in 1927 and put into production in 1932 by the local coal company Charbonnages du Maroc. High quality anthracite was mined from this 1000m field, and in the early 1990s it was producing 600 000 tons per year. It was the only coalmine in the country until the main works finally

To facilitate efforts at diversification and meeting the increasing demand, a decree was introduced in 1994, which opened the door to private participation in the generation sector. With Moroccan law dictating that private firms may not own electricity infrastructure, arrangements were pre-specified as BTO (Build-Transfer-Operate) schemes (Badawi 2001:10).¹⁵⁸ Furthermore, ONE was designated as the exclusive buyer of all power above 10 MW through decree no. 2-94-503 of 23 September 1994 (Benhima 1999:34; Debbbarh 2006). Shortly thereafter bidding for the first IPP commenced, the details of which will be discussed in section 5.3 together with those relating to the country's other two IPPs.

With the addition of IPPs that have come on line since 2000, as well as a number of upgrades to ONE's generation capacity, Morocco's installed generation capacity has been increased to 5232 MW, responding to a demand of 19 822 GWh in 2006 (ONE Annual Report 2006). Of the installed capacity, thermal plants account for roughly 69 per cent, hydro, 30 per cent and the remainder is made up by wind farms. Important to note, however, is that actual generation from hydro, has accounted for less than 10 per cent of national production since 2004. With the country's poor hydrological conditions over the past few years, hydro generation has experienced a notable drop of 18 per cent between 2004 and 2007, with its share in the generation mix reducing to 6 per cent in 2007 (World Bank 2008c). Table 5.1 gives a breakdown of Morocco's installed generation capacity in 2007.

closed in 2001 after many years of declining output. The mine mainly supplied ONE's Jerrada Thermal Power Station until it closed.

¹⁵⁸ This is different to the BOT (Build-Operate-Transfer) schemes which have been more common around the world. The transfer of generation assets to the state utility allows private operators to manage the assets while ownership remains with the state.

Table 5. 1: Installed Generation Capacity in Morocco in 2007

Production Units	Installed Capacity (MW)	Total (MW)
26 Hydro	1265	
Pump Storage Scheme	464	
Total Hydro		1729
2 Coal-fired plants	1785	
3 Fuel-oil plants	600	
Gas-fired plants	999	
Diesel-fired plants	69	
Total Thermal		3453
Wind turbines	110	110
Combined Capacity		5292

Sources: ONE Annual Reports

The move to diversify away from hydro and so moderate the effects of drought has proved to be a challenging task with the country having limited domestic fossil fuels. Although Morocco possesses oil and gas wells, generally speaking, the calorific value of the fuels or the quantities estimated are too low to make exploration economic. A number of foreign exploration companies (20+) have exploration concessions and continue to search for oil and gas deposits both on and off shore. In 1998, Morocco's gas reserves were estimated at about 1.4m³ billion, its proven oil reserves were estimated at around two million barrels, while recoverable coal reserves represented approximately six millions tons (African Energy 1999:5). The country, therefore, has virtually no known indigenous coal, oil or gas reserves, importing roughly 96 per cent of commercial energy requirements. The remaining 4 per cent from domestic sources is mainly composed of hydro generation (Boutaleb 2005:16; Ministry of Mines and Energy 2008a:5).

In 1996, the Maghreb-European gas pipeline was commissioned to transport Algerian gas to Spain (Debbarh 2006:78). Construction of this gas infrastructure paved the way for Morocco's third IPP which employs a combined cycle facility to generate electricity.

Despite the increases in electricity production, growth in demand for power has once again outstripped the country's ability to acquire sufficient generation capacity. Power imports from Spain have increased from 3.4 per cent in 2005 to more than 9 per cent in 2007, with no large scale facilities to be commissioned before 2009/2010.

5.2.3 Future Plants and Fuel

Morocco's windy coastline has led to its keen interest in wind energy. Having adopted the Kyoto Protocol in January 2002, the ratification of the Clean Development Mechanism has opened up new sources of financing for renewable energy projects and the promotion of green energy (TERNA 2004:8). In addition to the country's second IPP, ONE commissioned a 60 MW wind farm in the Essaouira region in April 2007.¹⁵⁹ Morocco has plans to develop more wind farms, having launched a Request for Proposal (RfP) in 2006 for the next wind project for a 140 MW plant in Tangier, which is in its construction phase in 2008 and expected to be operational in 2009. The country also has plans to develop the Touahar à Taza wind farm, with an expected capacity output of 100 MW. It is the country's intention to eventually have 14 wind farms at various locations to exploit the kingdom's wind potential and bring the wind capacity to 1000 MW (ONE 2007b).

In 2006, ONE also invited expressions of interest to develop a 1320 MW coal fired IPP in Cap Ghir under a 30 year PPA with ONE assuming responsibility for fuel procurement (Blum 2008). In February 2007, 15 companies were pre-qualified, out of an initial 30 companies that responded to the bid for the project, which was estimated to cost in the region of US\$1.5 billion (U.S. Commercial Service Morocco 2007). In October 2007, it was reported that the project at Cap Ghir had been scrapped due to environmental challenges and concerns about the impact of the power station on the local tourism industry, and that ONE was investigating an alternate site to develop the plant (MEED 2007a). The project, which was already a year late before a sponsor was selected to develop the plant, has since identified a new site. Despite moving to this new location in order to address the initial environmental concerns, it is intended for the plant to have clean coal technologies installed pushing up the price by approximately US\$300 million (MEED 2008). At the alternate location a new coal terminal would need to be developed, and while construction on the terminal could start as early as March 2009, it would take at least 40 months to complete, threatening the commissioning deadline of the new plant, which was set for 2011 in 2006 (Africa Electra 2007). As a result of the time lost and despite the plant initially scheduled to be commissioned in 2010, ONE has had to revise its energy plan, with the commissioning schedule postponed to 2012 and 2013 (ONE 2008).

¹⁵⁹ Apart from the three IPPs that were developed since power sector reforms were initiated in 1994, by 2008, the 60 MW wind farm was the only capacity addition commissioned by ONE.

Cap Ghir was not the only project to have experienced delays so early in its development. Although bids were submitted in March 2006 for the construction of the Al-Wahda combined cycle power plant, plans for this plant have also fallen behind schedule due to Morocco's insufficient domestic energy resources and political tensions with neighbouring Algeria which would supply the gas required to feed the plant.¹⁶⁰ The importation of liquefied natural gas (LNG) from Nigeria has since been considered as an alternative. Even if this proves possible, it would still take a considerable amount of time since a LNG receiving terminal would first have to be developed, delaying the development of the much needed capacity (MEED 2007b). As a result of the fuel supply issues, the development and commissioning of the Al-Wahda facility has been pushed back until 2011.

A second combined cycle plant unit was planned to come on stream at Tahaddart in 2010 (Boutaleb 2005). It was hoped that this plant would optimise the use of the Maghreb-Europe pipeline traversing Morocco and the royalties paid by Algeria, and further diversify Morocco's primary energy mix for power generation. At this stage, however, it is uncertain whether this unit will be an IPP. If problems relating to fuel concerns persist, it may be necessary to build a LNG terminal, creating a delay which could set the project back by five to six years (Ministry of Mines and Energy 2007:25).

Morocco thus continues to face uncertainty over the availability of fuel to supply current and future plants (North Africa Infrastructure Development 2007:49). Still conscious of its vulnerability in terms of energy dependence, Morocco's efforts to further diversify its energy sources have commenced with studies to investigate the feasibility of generating electricity from commercial nuclear reactors¹⁶¹. It is not foreseen that these units will become part of the

¹⁶⁰ Historically, tensions between the two nations have been over the phosphate-rich territory of Western Sahara. In addition to the Sand War which was fought over mineral rich border territory as far back as 1963 and 1964, since 1975 when Morocco took control over Western Sahara, Algeria has overtly backed the Polisario Front freedom movement to gain their independence from Morocco. Although Morocco has no oil reserves, through Western Sahara it controls over two thirds of the world's rock phosphate, an essential nutrient in global fertiliser supply, which experienced a price increase of 300 per cent in 2007 (The Oil Drum 2008).

¹⁶¹ An agreement signed with the French in the early 1980s has facilitated the initiation of these studies. The Sidi Boulbra site between Safi and Essaouira has already been identified as the best option for the plant. Although Morocco's experience with nuclear power has been limited to its 2 MW experimental nuclear plant in Maamora (African Energy 1999), its domestic energy shortages have left policy makers with few alternatives in the long run.

ONE fleet in the near to medium future due to the size of commercial units available and the relative small size of the Moroccan transmission network. Although the option of medium sized reactors is being considered, such reactors would only be economically viable if a programme of successive units were to come on line (Bencheqroun 2005).

5.2.4 Transmission and Distribution

Since independence, Morocco has had transmission links with neighbouring Algeria. Traditionally, the country was an exporter of electricity to Algeria until 1974, after reaching a peak in exports in 1968. This exchange of power was resumed in 1988 when the transmission grid was connected to the Algerian network at the 225kV level, this time with power flows reversed as Morocco faced a shortage of power due to the drought that had strained hydro generation. The initial exchange capacity was restricted to 200 MW until a second line was installed in 1992, with imports reaching a peak in the following year. At the same time, the government of Morocco also started negotiations with the Spanish power utility, Red Eléctrica de España (REE), to develop transmission links with Morocco in order to help overcome Morocco's power deficit.¹⁶² By 1997, Spain took over from Algeria as the main electricity exporter to Morocco and trade with Algeria has since been limited to mutual spot back-up to balance supply and demand (Morocco Country Profile 1998; Debbarh 2006:70). In 2006, the capacity of the 400kV interconnection with Spain was doubled to relieve domestic electricity supply shortages, and, in anticipation of potential future power shortages, a third 400kV interconnection was established with Algeria (Debbarh 2006:87).

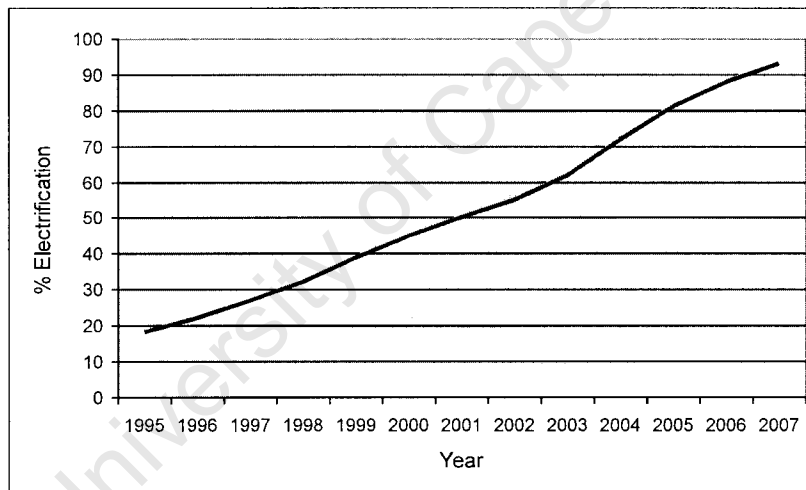
The existence of the abovementioned transmission interconnections have proved to be of great importance to the country. Since power sector reforms were first introduced in 1994, Morocco has been unable to meet its electricity demand through domestic production alone and has had to source electricity imports to overcome the shortages. Despite adding capacity from IPPs to the country's grid, in 2007 Morocco still had a shortage of electricity, importing more than 9 per cent of the country's electricity requirements, a figure which is above the average volume of electricity imported during the last decade, and a sharp increase from the 3.4 per cent of national demand volume imported in 2005 (ONE 2006a; ONE 2008). Were it not, therefore, for the ability to import power from its neighbours through these transmission interconnections, the consequences of Morocco's power shortages would have been more

¹⁶² The contract for the initial interconnection was signed by ONE and Red Eléctrica de España (REE) in July 1993 when Morocco was suffering from a severe energy crisis.

severe. Despite the cost of power imports being more than the cost of domestic production, in all probability, imports will be the primary means used to manage the shortfall in electricity production in the short to medium term, as has been the case since 1988.

More recently, expansion of the national distribution networks have been mainly at the lower voltage levels and largely driven by the goals of the country's Rural Electrification Programme, PERG (Programme d'Electrification Rurale Global), which was expected to be completed by the end of 2007. In 2007, rural electrification rates were recorded at 93 per cent, up from 18 per cent in 1995, as illustrated in Figure 5.3. This notable performance in rural electrification puts Morocco amongst the countries that have the highest electrification access rates on the African continent.

Figure 5. 3: Rural Electrification Rate between 1995 and 2007



Sources: ONE Annual Reports

At the end of 2006, ONE accounted for approximately 37 per cent of the total distribution market amongst medium and low voltage consumers (ONE Annual Report 2006:16). Seven regional municipal distributors made up about 15 per cent. The remainder, approximately half of the country's distribution market, is controlled via long-term contracts by three private firms, under the supervision of the Ministry of the Interior and Urban Centres (Jerjini 2002). Lydec is the largest of the three private distributors, holding the rights to provide electricity services for 30 years for Casablanca (since 1997) and represented almost 40 per cent of the country's total distribution sales in 2006. Redal has held a 30-year contract for Rabat since 1999 and, in 2006, represented 17 per cent of the distribution sales. Finally, since 2002, Amendis has been active in Tangiers and Tetouan under two 25-year contracts, and represents

about 9 per cent of the country's distribution sales (ONE Annual Report 2004; ONE Annual Report 2006:19).

5.3 Independent Power Producers

As previously noted, IPPs have helped to change the face of Morocco's ESI, providing much needed generation after the troubled years of the mid-1980s and early 1990s. This section describes the three independent power projects that have come on line since the start of the reform programme. The projects are distinct in size, fuel source, and construction costs, as illustrated in Table 5.2 below. The first IPP, the Jorf Lasfar Energy Company (JLEC) uses coal and consists of both a brownfield and greenfield transaction. The second IPP, Compagnie Eolienne de Detroit (CED), is a wind farm. The third plant, Energie Electrique de Tahaddart (EET) uses gas from neighbouring Algeria to run the country's first combined cycle gas plant.

Table 5. 2: Summary of Moroccan IPPs

Total Project Cost	US\$ 1.5 billion	€ 45.7 million	€ 285 million ¹⁶³
Nominal Capacity	680 + 680 MW	50 MW	384 MW
PPA Duration	30 years	19 years	20 years
Fuel Type	Coal	Wind	Natural gas
Debt	Foreign	Foreign	Local
Equity	Foreign	Foreign	Local / Foreign

Although technologically varied, these projects had a standard set of investment incentives, including VAT and customs duty exemptions on all equipment that could not be sourced locally and a five year holiday on property tax. In terms of corporate income tax, there was a slight variation among the three projects. For Jorf Lasfar, the first IPP, a full exemption was granted for the first five years of operation, followed by a 50 per cent reduction from year-six to year-ten. For CED, the second project, the firm received only a 50 per cent exemption during the first five years, after which the normal tax rate of 35 per cent applied. Finally, the fact that EET was located in one of the region's investment zones meant that it qualified for a

¹⁶³ In local currency, this amounts to roughly MAD 3013 million.

75 per cent income tax exemption during the first five years.¹⁶⁴ From year six to ten, a 50 per cent exemption is scheduled, similar to that given to JLEC. All exemptions were scheduled to start from COD and thereby reduce overall financing charges facilitating investment in generation infrastructure.

5.3.1 The Jorf Lasfar Energy Company

a) Project Overview

Unlike any of the other projects described in this thesis, Morocco's first IPP, a 1360 MW coal-fired plant, was both a brownfield and greenfield development. Shortly after the first and second units, consisting of 340 MW each, came into service in October 1994, the government launched an international competitive bid (ICB) for additional capacity. The deal consisted of building two more units (as well as expanding the coal supply terminal) and operating the power plant (including units one and two) for a period of 30 years under a BTO agreement.

The three consortia that responded were:

- Asea Brown Boveri (ABB) and CMS
- AES and General Electric (GE)
- Alstom¹⁶⁵

The CMS/ABB consortium was ultimately selected in 1995, in part due to ABB's track record in Engineering, Procurement and Construction (EPC) and CMS's recognised expertise in Operations & Maintenance (O&M). The firms had partnered in a number of IPPs internationally and, thus, together, the two companies were able to demonstrate that they could adequately share the technical and project management risks normally associated with large projects of this nature.

Negotiations with the ABB/CMS consortium continued until April 1996, when agreement was reached on the draft PPA. The PPA was finalized in September 1997 when negotiations

¹⁶⁴ The Tahaddart plant is located in a free trade zone in Tangiers which is open to both Moroccan and foreign companies. Companies located in the zone may import goods duty-free and qualify for certain tax exemptions depending on the business concern.

¹⁶⁵ Alstom was the EPC contractor for the first two units of Jorf Lasfar and, therefore, had previous experience with the power station.

for the O&M agreement, the EPC agreement and the financing arrangements were concluded. A performance bond of US\$50 million was posted by ABB/CMS as a guarantee that they could arrange the project financing.

In January 1997, the Jorf Lasfar Energy Company (JLEC) was incorporated as a Moroccan company to start operating units one and two for which JLEC paid US\$263 million to ONE.¹⁶⁶ Many personnel for the operation of the plant were subsequently transferred from ONE to the new company and a series of new support functions for JLEC was established. For units three and four, work began in September of 1997, and was scheduled to be completed approximately three years later. With the project slightly ahead of schedule, COD for unit three was reached in June 2000 and for unit four in February 2001.

b) Financing

The brownfield and the greenfield components of the deal were treated as one transaction. Equity, accounting for US\$500 million or approximately 33 per cent of total financing, was made up of two tranches: US\$300 million provided initially as a shareholder loan and then converted into equity, and US\$200 million from surplus cash flows from the operations of units one and two. The project debt of US\$1 billion was made up of five sets of loan agreements, with interest rates varying between 5.7 per cent and 10 per cent depending on the loan facility.

The US Export Import Bank (US ExIm) is a senior lender with US\$200 million of loans issued at an interest rate of 7.2 per cent. An additional US\$200 million credit facility was extended by the Overseas Private Investment Corporation (OPIC). The commercial bank loans are backed by political risk guarantees from the Italian Export Credit Agency, SACE (Servizi Assicurativi del Commercio Estero),¹⁶⁷ the Swiss Export Risk Guarantee (ERG)¹⁶⁸

¹⁶⁶ Exemption on corporate income tax referenced earlier included income from the two brownfield units.

¹⁶⁷ SACE S.p.A. is a joint-stock company fully owned by the Italian Ministry of Economy and Finance. Their commitments are guaranteed by the Republic of Italy. The insurance company supports Italian business throughout the world and insures, reinsures and guarantees political and commercial risks affecting Italian enterprises in their export or investment activities.

¹⁶⁸ The Export Risk Guarantee (ERG) is a Swiss federal government scheme designed to make it easier for exporters to do business in countries where political or economic instability could jeopardise receipt of payment. The ERG is a legally dependent, self-supporting fund managed by the Swiss federal

and the World Bank. After syndication, the project started with 50 commercial banks. This number has since been reduced to less than 45 due to mergers and buyouts. As security for these loans, the Government of Morocco issued JLEC with a letter guaranteeing it the right to operate the power station and, in the event of default, that ONE would make the termination payments. The fact that transfer took place before operations commenced was very important to investors and lenders in the BTO context given their concerns regarding the risk expropriation as described in section 2.4.

c) The Power Purchase Agreement

Although the above noted security arrangements helped to sweeten the deal, it was the PPA that supported the whole transaction. The PPA tariff schedule was front-end loaded with the tariff peaking in the fifth year and tapering off to year thirty. Payments are based on the energy that JLEC makes available for dispatching, with the PPA stipulating that JLEC guarantees a minimum energy availability factor of 82 per cent. As is standard for IPPs globally, these payments include a capacity charge, an O&M charge, and an energy charge based on the cost of the primary energy consumed in accordance with the prescribed heat rate curves for the plant hardware. At the end of the 30-year contract, ONE will automatically assume operations for the full installation with no financial payment. Thereafter, the decision to extend the period of plant operation will be up to ONE.

Included in the terms of the PPA was an escrow facility equivalent to one month of invoicing. The agreement also contains a clause stating that if no payment dispute is entered into during the first four years of the contract, ONE could request a reduction to zero in this cash escrow account, which is what happened. As security against a payment default, the PPA requires ONE to establish and maintain a letter of credit in favour of JLEC equal to two months of invoicing.

d) Fuel Supply and Agreement

All four units use coal for which JLEC is reimbursed according to the following formula:

- 80 per cent - the average cost of coal procured by JLEC
- 20 per cent - the average cost of coal imported into the European Union.

government. It derives its income from guarantee fees and borrowers' repayments from debt rescheduling.

This arrangement acts as an incentive for JLEC to procure coal at a competitive rate. As mentioned earlier, with Morocco having virtually no indigenous coal supply, all of JLEC's coal supply is imported (mostly from South Africa). Thirty-five days of stockpiling is required in terms of the fuel security agreement. The choice of coal as fuel was linked to three factors: the existing two units already used coal as the source of primary energy, the proximity of the Jorf Lasfar coal terminal, and the competitiveness of the fuel type.

5.3.2 Compagnie Eolienne de Detroit (CED)

As the largest IPP in Africa, Jorf Lasfar towers over every other project, especially Compagnie Eolienne de Detroit (CED), Morocco's second IPP at only 50 MW (or less than 4 per cent of JLEC's installed capacity). CED is, however, a pioneer in its own right as Africa's first privately financed wind farm, and, therefore, is important to discuss in the context of both Morocco's and the continent's evolving power development.

a) Project Overview

Morocco's efforts at harnessing wind power date back to the 1980s when, in 1986, the Renewable Energy Development Centre, CDER (Centre de Développement d'Énergie Renouvelable) in Marrakech published the first wind atlas for the country. Four years later, CDER launched a special wind measurement programme, supported by the German Development Agency's Technical Expertise for Renewable Energy Application (TERNA) programme, to identify the most promising sites for wind energy utilisation.¹⁶⁹ The results of this programme, published in March 1995, indicated mean annual wind speeds of 11.5 m/s in the Tétouan region, near Tangiers in northern Morocco. Encouraged by these findings, which qualified the site as one of the best in the world, ONE subsequently created a programme for the development and promotion of wind energy. The goal of the programme was twofold: diversify Morocco's electricity sources and develop more sustainable energy alternatives.

The first wind project was a 3.5 MW demonstration wind farm at the Al Koudi Al Baïdi site.¹⁷⁰ To finance the project, the German Development Bank, Kreditanstalt für Wiederaufbau (KfW), provided a low interest loan of € 4.35 million to ONE. Following what was deemed a successful demonstration and in keeping with the government's initiative to

¹⁶⁹ Germany's Gesellschaft für Technische Zusammenarbeit (GTZ) sponsored TERNA which, in turn, supports partner countries in the assessment and utilisation of their wind energy potential.

¹⁷⁰ This is in the province of Tétouan, 40 km east of Tangiers.

draw on private capital to finance infrastructure projects, ONE began discussions with Germa, the French wind energy consulting company, as a first step to developing a 50 MW wind project. The discussions with Germa resulted in the wind consultancy being given the opportunity to share in the project's equity. To supply the equipment for the project, however, the government subsequently conducted an ICB hoping that the equipment supplier would take the remaining equity stake in the project. The ICB attracted bids from Nordex and Enercon, the German equipment suppliers, and Vestas, the Danish equipment supplier. Vestas, although providing the winning bid, indicated that its involvement would be limited to the construction of the plant, and that it had no interest in acquiring an equity stake. With Vestas' interest limited to that of equipment supplier, Germa entered into discussions with Electricité de France (EDF) and Paribas Merchant Bank since it needed equity partners for the project. The inclusion of these partners resulted in all the equity for the project being of French origin.

Project equity, which accounted for 30 per cent of total project costs, was therefore agreed to as follows: EDF 49 per cent; Paribas 35.5 per cent and Germa 15.5 per cent. Thereafter, CED was established as a special purpose vehicle (SPV) to realise the project, with first priority given to arranging debt financing. The European Investment Bank (EIB), senior lender to the project, provided a loan of €24.4 million for the €45.7 million project. Secondary lenders in the loan syndication were, among others, Credit Agricole (now Calyon) and the French development agency, Société de Promotion et la Participation pour la Coopération Economique (PROPACO).

b) Localised Financing and Payments

As with JLEC, ownership of the IPP ultimately resides with the state, and the 19-year PPA, which was finalized in 1997, specified a BTO arrangement. In a departure from thermal IPPs, however, only a capacity charge (i.e. no energy charge), is detailed in the PPA. Initially this payment is made in the form of a 70:30 ratio of US\$:MAD. With project debt paid off in the first ten years of operation, this payment ratio will gradually change so that towards the end of the PPA period most of the payment will be made in local currency.

Provision is made in the PPA for arbitration in Morocco in the case of any party failing to honour its commitments as stipulated in the agreement. Furthermore, according to the terms of the PPA, ONE has the right to take over the operation of the wind farm, but is obligated to pay CED an amount equal to the book value of the assets and the calculated future cash flows from the operation for the remainder of the PPA duration.

5.3.3. Energie Electrique de Tahaddart

As the country's first plant using combined cycle gas turbine (CCGT) technology Morocco's third IPP also maintains the status of a national record setter. Of perhaps greater significance, however, is the fact that Energie Electrique de Tahaddart (EET) is the first power plant in all of Africa where all the entire project debt was financed by local banks in local currency.

a) Project Overview

There were several factors that coalesced and led to the realisation of EET. First, in terms of fuel, the Moroccan government has the right to 7 per cent of the gas that passes through from Algeria to Spain (EET pers.com. 2006). Prior to the inception of EET, royalties were paid to the government in cash. With increasing electricity demand and pressure to diversify the supply mix, a decision was made to accept the gas commodity as payment as opposed to cash. The Government of Morocco was also motivated by the fact that the use of gas would help reduce the country's foreign currency demands and, albeit to a much lesser degree, minimise foreign exchange exposure, since the vast majority of Morocco's energy needs are purchased in foreign currency. Finally, the decommissioning of existing plant meant, quite simply, that new generation was needed.

With more than half of the country's electricity generation output produced by IPPs, ONE made a strategic decision to limit its retreat from the generation sector and become a shareholding partner in EET. Initially ONE engaged in talks with EDF and Empresa Nacional de Electricidad S.A. (ENDESA); however, EDF's interest was limited and short-lived and the firm soon opted out. These discussions, like those conducted in the early days of CED, were meant to prepare the terrain for the ICB by helping ONE to find partners who could assist in facilitating the tender and, ultimately, in carrying part of the project equity. In 1999, assisted by ENDESA, ONE issued an RfP for an EPC contract and an O&M contract. It was agreed by ONE and ENDESA that the successful bidder would take a 20 per cent equity stake. GE, ABB and Siemens pre-qualified, with Siemens ultimately chosen for both the construction and O&M contracts. The equity split was, therefore, as follows: ONE 48 per cent, ENDESA 32 per cent and Siemens 20 per cent.¹⁷¹ In addition to the other record setting aspects noted above, EET thus became the first shareholding partnership between ONE and private

¹⁷¹ Initially, ONE would only take a 20 per cent stake in the project, EDF a 30 per cent stake and ENDESA a 30 per cent stake. This changed when EDF left the negotiations (Morocco Country Profile 1998).

companies in Morocco's ESI. Construction started in February 2003 and COD occurred approximately two years later on 25 March 2005. A 20-year PPA, under BTO terms, specifies that ONE is the sole off-taker, as with both JLEC and CED, and that EET must guarantee minimum availability.

b) Financing

The project cost, amounting to €285 million, was made up by 25 per cent equity and 75 per cent debt, which represents a larger debt component than in any of the previous IPPs (with 67 per cent for JLEC and 70 per cent for CED). Debt was provided by a suite of Moroccan banks: Banque Centrale Populaire (BCP) provided MAD1300 million in loans; and a consortium of banks, which included BCP as the lead lender, the Banque Marocaine pour le Commerce Extérieure (BMCE) and Crédit Agricole (CNCA), provided an additional MAD960m in loans.¹⁷² Part of the debt is tied to a fixed interest rate at 7.6 per cent, and part varies with the prime interest rate. Although the debt is payable within the first 12 years of operation, a grace period of three years has been negotiated. This flexibility gives ONE the option of extending its payment schedule from 12 to 15 years in the event that its financial situation changes to an extent where it has to restructure its repayments. Apart from a letter of credit issued by a local bank (equal to one month's payment), there are no escrow facility requirements or any other security arrangements. In the case of default, however, the PPA does make provision for international arbitration at the International Council for Commercial Arbitration in Geneva, Switzerland.

5.4 An Analysis of the Hybrid Power Market and its Outcomes in Morocco

Morocco has seen a significant increase in private participation in generation where private operators today supply the bulk of the country's power. Private participation is also prevalent in the distribution sector where private distributors service the major urban centres. Despite the changes that have occurred, the realisation of a competitive power market resembling the standard model remains elusive. This section provides an analysis of how post-reform power sector frameworks have impacted on the development of generation infrastructure.

¹⁷² The average exchange rate for the Moroccan dirham in 2003, the year that construction started, was 10.95MAD=1.00EUR (Interbank Rate).

5.4.1 Post-Reform Electricity Market Evolution

As with many hydro-dependent systems, it was droughts in the 1980s and early 1990s that, in part, prompted policy makers to initiate changes to electricity policy in Morocco. Prior to this, between the 1950s and early 1970s, hydro had met the lion's share of the country's demands and policy makers had come to take weather reliability for granted.¹⁷³ Although ONE's thermal capacity was on the increase in the 1980s and 1990s, new investment did not keep pace with demand, which, compounded with the drought, resulted in power shortages and significant load shedding. These power scarcities served as a wake up call to the country and to policy makers, ushering in a new awareness of the importance of strategic planning and the need for the diversification of fuel resources, as well as a call for additional financing of generation investment. In addition, poor utility financial and technical performance contributed to the need for transformation in the sector. The enactment of legislation ending ONE's monopoly in 1989 paved the way for private producers to supply more than 70 per cent of the country's production by 2005. This has resulted in a hybrid arrangement where private producers and the state-owned utility together supply electricity, but where the utility is also the off-taker of electricity from IPPs.

ONE has undergone a transformation from a traditional SOE to a public corporation that is operated under Moroccan commercial law (World Bank 2008c). Despite corporatisation, the performance of ONE is still unsatisfactory largely due to the current financial difficulties within the organisation. Although the sector has seen significant changes since power sector reforms were initiated, institutionally there have been few changes to accommodate the new market structure and operational arrangements. The overall institutional framework, therefore, resembles that of the sector prior to reforms: there is no independent regulator and most of the initiatives and functional responsibilities, including planning, procurement of generation and dispatching, are spearheaded by the national utility under the tutelage of the Ministry of Energy.

Although the evolution toward the standard model with competitive wholesale markets is still in the pipeline for the Moroccan ESI, delays have been experienced in its implementation and the transition towards competition in the sector has met with numerous challenges as outlined by Woolf and Halpern (2001) in Chapter 2 of this thesis.

¹⁷³ The early 1970s marked the first time that fossil fuels accounted for more than renewable or hydro facilities for electricity supply in Morocco (ONE 2003:89).

5.4.2 Power Sector Planning

Prior to reforms, power sector planning was the responsibility of ONE. Unlike in the two previous cases, Ghana and Côte d'Ivoire, where the planning function was taken away from the state utility and given to new institutions set up for this and other functions, the planning function has remained with ONE since reforms first started in 1989. Although domestic production did not increase sufficiently to meet the demand between 1989 and 2005, there was a decrease in the shortfall as a percentage of national demand. After 2005, the deficit has once again started to increase and, despite nearly 20 years of ongoing reforms, Morocco has been unable to eliminate its net deficit in generation through domestic generation sources.

The question that arises is: Why, despite so many years of reform, is the electricity sector seeing its largest deficit between national demand and national power generation? While there has been relative continuity in the planning function in the transition between the pre and post reform periods, the outcome appears to be mixed when one compares the period up until the last IPP (EET commissioned in 2005) when the generation shortfall was decreasing, with the period thereafter where it has been on the increase. During the latter, ONE has been unable to meet domestic demand without a substantial increase in the amount of power imported from neighbouring Spain. Despite indications that the pace of supply side additions was falling behind, Morocco continued to pursue its ambitious rural electrification programme which significantly increased demand. The PERG was considered a priority: sufficient funds were secured for the PERG, but not enough for additional generation investment.¹⁷⁴ In addition, assigning the bulk of the operational responsibility for electricity production to private producers enabled ONE to remain operationally focused on PERG. The utility's DSM programmes that were rolled out to encourage energy efficiency as a means to curb demand growth were only instituted when the supply situation reached crisis proportions in 2008. The timing of these actions, therefore, suggests that inadequate planning to balance demand and supply was a problem in the sector. This continued to be a problem in 2008 when the transmission and distribution networks failed to ensure a reliable supply of electricity supply to all consumers resulting in costly disruptions to industry and the economy in general.

¹⁷⁴ The increase in rural electrification rates has helped counter the rapid urban migration, which was prompted, in part, by the droughts during the mid-1980s and early 1990s. PERG also has contributed to the economic, social and educational development that resulted from electrifying remote settlements.

a) Generation Project Planning

There have also been shortcomings in the assessment of project related risks. Environmental risk assessment emerged as a weak point within generation planning with the Cap Ghir plant being delayed due to environmental concerns over air pollution and the impact that it would have on tourism in the area. The risk assessment of upstream fuel security emerged as the weakness in planning for the Al Warda plant, with the government and utility failing to secure sufficient fuel in time for the development of the project and construction of the plant. In the case of the Cap Ghir plant and with Morocco's historical environmental performance in the power sector, it may be deduced that environmental concerns were not high enough on the agenda for project planners and that critical links between the planners and environmental agencies were insufficient.¹⁷⁵ Although the plant would be built by the private sector, the site selection still remained the responsibility of ONE and the state. It would appear that ONE had not kept up-to-date with modern environmental requirements for coal-fired plants.¹⁷⁶ The initial planning also failed to take into consideration the increased costs of dealing with the environmental concerns, including the installation of clean coal technologies as noted in Section 5.2.3. For the Al Wahda plant, negotiations for fuel should have been done at a governmental level since the associated problems were political in nature, rather than technical, environmental or commercial. Given the critical nature of the country's dependence on foreign energy imports, it is startling that the importance of fuel security was underestimated.

b) Flexibility in Planning

Although there have been problems relating to the planning of generation projects, the overall planning with respect to electricity provision appears to have been flexible enough to overcome these problems – at least to some extent. Regional integration with respect to transmission interconnections has helped Morocco to maintain adequate electricity to meet demand. The utility, supported by the state and the World Bank, has been proactive in further integrating its transmission networks with those of Spain and Algeria so as to import electricity instead of fuel used for power generation. This arrangement has helped the country deal with its immediate electricity shortages. Over the medium to long term, however, this alternative as a single solution has a problem of its own: the existing transmission grid in

¹⁷⁵ Prior to CMS/ABB taking over the Jorf Lasfar plant, waste fly ash was not disposed of in an environmentally friendly manner but simply pumped into the sea.

¹⁷⁶ The last coal-fired power station planned by ONE was more than two decades prior to the planned construction of the Cap Ghir plant.

Morocco is overloaded and, in many areas, is already operating at the limits of its capacity. Voltage and frequency drops have made the transmission system unstable and ONE is experiencing high transmission losses due to demand load centres being far from supply. This situation is expected to deteriorate unless the transmission system is strengthened. According to a World Bank report detailing the status of the Moroccan ESI, transmission strengthening is required before any new power plants are commissioned (2008c:107). Either way, the country has to spend money on transmission infrastructure reinforcements to stabilise the network and make provision for future growth in both power supply and demand.¹⁷⁷

Meanwhile, the government and ONE have also crafted a strategy to deal with the domestic power shortages in the short to medium term. In a press release in July 2008, the Ministry of Mines and Energy stated that it planned to develop over 1000 MW of wind energy or roughly 20 per cent of 2008 capacity by April 2010. It also plans to augment the transmission capacity from Spain by 700MW by installing a third undersea cable, while at the same time reinforcing its transmission grid infrastructure. Included in the planning schedule is a DSM programme to reduce demand and another programme to improve the performance of ONE generation plants (ONE Annual Report 2006; Ministry of Mines and Energy 2008b). A law permitting self producers to operate installations above 10 MW has also been approved with self producers now able to install generators with a capacity up to 50 MW (ONE 2008:10). While these measures may help in alleviating the problems of capacity shortages, on their own it is uncertain whether Morocco will be able to weather the storm.

c) Financial Planning

Growth in electricity demand has accelerated from 6 per cent per annum between 1997 and 2002 to more than 8 per cent per annum between 2003 and 2007, and is expected to continue growing at a relatively bullish rate until 2015 (World Bank 2008c). ONE has been struggling to survive financially mainly due to rising fuel costs which have not been matched by corresponding increases in tariffs; the World Bank described ONE's need to redress its financial situation as its most pressing and immediate challenge (World Bank 2008c).¹⁷⁸

¹⁷⁷ ONE has applied to the World Bank for a loan to enable the necessary upgrades to the transmission infrastructure to cope with fast growing demand and meet the quality and security requirements.

¹⁷⁸ While fuel prices have more than doubled between 2004 and 2008, the average tariff increased from US\$8.8 cents in 2004 to US\$ 9.5 cents in 2007. This represents less than an 8 per cent increase over the four years (World Bank 2008c). Between 2003 and 2005, the cost of charges from Jorf Lasfar and Spain rose by an average of 14 per cent (Barbut 2006:16).

Although ONE has requested a tariff increase along with a complete overhaul of the tariff structure, electricity tariff increases are a socially sensitive issue and the state's view is that these must be accompanied by and coordinated with measures to protect the poor. Current tariff structures only allow for minimal absorption of increasing operating costs among the lower income groups that have been granted access as part of the country's rural electrification programme. The tariff issue is further exacerbated because the majority of users fall into the lower income category. Only a 7 per cent tariff increase was approved in 2006, the first tariff increase since 1997, and it was almost insignificant when compared to the escalation of costs at the utility (Barbut 2006:16-17).

ONE's borrowing expenses have increased by 26 per cent from 2004 to 2007 and the utility's debt in 2007 represented around two thirds of its balance sheet. Assets include accounts receivable, amounting to more than US\$230m and which have proved to be hard to recover.¹⁷⁹ By early 2008, ONE had also requested the Government of Morocco to write off its debt and, by mid-2008, ONE and the Government of Morocco were in discussions on a fiscal recovery plan for the financially stricken utility. Current projections show that ONE will continue showing a loss well into 2012 unless changes are brought about to the tariff structure or adjustments are made to the SOE's balance sheet, through capital injections, amongst other things (World Bank 2008c).

5.4.3 Procurement of Generation

The country's first IPP, JLEC, was procured through an ICB and, although only three consortia responded to the bid invitation, it did provide for some degree of competition amongst bidding consortia putting downward pressure on tender price submissions. The World Bank had posted a guarantee and with its involvement in the Moroccan ESI, ONE, the state, and other project stakeholders were obliged to conform to the bank's procurement policies for projects that relate to infrastructure spending.

For the second IPP, tenders invited for the development of the project were not for the entire equity on the project. Since Germa had already done much of the feasibility study on the development of the wind farm, the project lead was awarded to the consultancy by ONE and

¹⁷⁹ Long standing arrears from previous municipalities that historically serviced the Casablanca and Tetouan regions amount to MAD 1062 million with short-term overdraft financing costs for these accounts receivable estimated to be in the region of MAD 80 million (World Bank 2008c:182).

the state. Although the main developer had already been chosen, it was still required that the bulk of CED's project costs, the EPC, be procured by international tender in accordance with the prescriptions of the lenders to the project.

A similar arrangement was used in the development of the country's third IPP. ONE had decided from the onset that it would take an equity stake in the project. It then selected the equity holders it wanted as partners in the deal. ONE and its selected partner, Endesa, put out a tender for the EPC contract, with the idea that the winner would be an equity partner in the development of EET. This made ONE a co-supplier and off-taker of the power generated through the IPP arrangement purchase agreement. Nevertheless, ICBs for the three IPPs that were commissioned assisted in lowering costs to the utility and ultimately consumers. At the time shortly after commissioning Morocco's first IPP, the Global Environmental Facility reported that the power charges to JLEC amounted to 4.8 US\$ cents per kWh which compared favourably to the costs of ONE plants, which were slightly higher at around 6 US\$ cents per kWh (GEF 1999:9).¹⁸⁰ The German Ministry for Economic Cooperation and Development has disclosed that the generation price for CED was calculated at MAD 0.40 to 0.60 per kWh (3.9 to 5.9 € cents per kWh), placing it in the range of the average production costs of conventional plants in Morocco and comparing favourably with green energy prices elsewhere in the Mediterranean region (GTZ 2002:155).¹⁸¹ Finally, EET also fared quite well with an estimated tariff of around 3 US\$ cents per kWh (excluding the gas), which compares well with similar projects in the region (Sadiq 2001; Euro-Med Energy Forum 2008:8).¹⁸²

¹⁸⁰ One of the ways in which ONE contractually tried to keep costs down was to give JLEC an incentive during coal procurement. For JLEC to attain or exceed expected Return on Equity (ROE), it needed to procure coal at a less costly rate than purchasing coal imported into the European Union. Although ONE, as the off-taker, has control neither over the fuel supplier nor over the international coal price, the utility has created an incentive for JLEC to keep primary energy costs down, exerting downward pressure on the cost of a kWh.

¹⁸¹ Of significance in CED's power charges is the way in which the capacity charges are paid. As there is no primary energy charge, ONE was able to negotiate up to 30 per cent of the capacity charge to be denominated in local currency at the onset of the agreement, thereby decreasing foreign exchange exposure.

¹⁸² From a currency perspective, EET may ultimately prove to have among the most stable power charges of any project on the continent largely due to local financing. As has been previously discussed, all the debt for the project was locally sourced, and in local currency and nearly half of the project's equity is domestically held. The lead lenders for the debt were local banks which were previously state owned and still had a significant degree of state involvement at the time the financing

When JLEC came on line, it supplied roughly two thirds of national electricity production. Similarly, when EET came on line, it represented approximately 11 per cent of the country's installed capacity and roughly 17 per cent of total domestic generation output. Accounting for the bulk of the country's electricity production, IPPs do not appear to have caused price increases in local currency in Morocco, unlike elsewhere in Africa (namely in Egypt, Ghana, and Tanzania).¹⁸³ Instead, during the period that IPPs have been developed, ONE was actually able to reduce electricity tariffs. Table 5.3 shows the reductions in the various voltage categories recorded in nominal terms, with real term reductions for medium and high voltage categories measuring 44.4 per cent and 36.4 per cent, respectively, for the same period. These reductions have helped to make the economy more competitive, among other things, and attract business to Morocco (Debbarh 2006:81). However, as noted above, more recently, tariffs have not kept up with costs and have led to financial difficulties for ONE.

Table 5. 3: Tariffs in MAD cents per kWh.

Tariff Category	1997	2004	% Reduction
High Voltage	81.7	61	25%
Medium Voltage	101.8	69.9	31%
Low Voltage	93.2	86.4	7%
Residential	78.79	73.9	6%

Source: ONE Annual Report (2004:21)

Although the presence of ONE as an equity partner in the third IPP had clear benefits when it came to arranging local finance from Moroccan banks (since ONE is backed by the state), the equity arrangement in the EET IPP was a departure from the norm of full private sector participation in IPPs in Morocco since ONE assumed nearly half the equity in the project. Other than the fact that ONE had some financial reserves to invest in the project's equity, it is unclear why it decided to get involved in the project since general criteria for the allocation of new build opportunities for SOEs and the private sector have not been made public by the utility or the state.

arrangements were negotiated. It is, therefore, doubtful whether similar local debt financing would have been realised with historically private banks alone and without the influence of the state. Nevertheless, the arrangement has helped significantly in doing away with the currency risks that have plagued similar projects in other emerging countries.

¹⁸³ At least this was the case when fuel costs remained relatively constant.

Again, it is ONE that will develop the next wind farm despite the fact that the utility's finances are now in a dire state. Recent experiences have shown that the private sector's appetite for IPPs appears to have waned in Morocco with no private bidders being interested in the Ain Beni Maihar plant (World Bank 2008c). Given this, it is understandable that the state has had to take a more direct lead. However, if the sector's finances were in a better state, it is likely that greater interest would be expressed by private sponsors.

5.4.4 Contracting Arrangements

As the primary off-taker of power in the sector, ONE has entered into contracts with all IPPs in accordance with the country's legal framework.

Both parties are bound by the conditions of the contracts which make provision for dispute resolution. Contract terms serve as the primary regulatory mechanism for meeting the objectives of both stakeholders (sponsor and off-taker) in a transparent manner. Investment contexts, however, often change from the conditions experienced at the inception of contracts and such changes have the potential to put stresses on existing contracts and impact on the nature of future ones. From the time that the contracts for the three IPPs were entered into, much has changed. The utility's financial performance has deteriorated significantly. As noted previously, poor hydrological conditions have resulted in a significant decrease in hydro generation and the utility's costs have seen a marked increase mainly due to escalating fuel costs over recent years. Meanwhile, tariffs approved by the state have not seen an increase sufficient to cover increased costs. This has contributed to the utility's poor financial performance.¹⁸⁴ The deteriorating financial situation may potentially impact on the utility's ability to make timely payments to IPPs thus discouraging future investments by IPP sponsors.

a) PPA Charges

One element in the PPAs is that charges are heavily loaded in the early years of the contract and reduced later. Charges paid to JLEC peak in year-five and slowly taper off to the end of

¹⁸⁴ Unfortunately, in Morocco, reductions in tariffs during the period from 1997 to 2004 were not matched by a corresponding increase in tariffs when costs started to escalate. In some cases, prices of a number of energy commodities were frozen to avoid social unrest, and subsidies remained during the time of increasing global energy commodity prices despite Morocco's policy of gradually doing away with subsidies (World Bank 2008c:73).

the PPA period. In the case of CED, although the PPA duration is 19 years, the project debt is scheduled to be paid within the first 10 years of operation. Similarly with Tahaddart's 20 year PPA, the debt is scheduled to be paid within the first 12 years, with a debt rescheduling buffer option consisting of an additional 3 years. Although this type of arrangement reduces overall financing costs and decreases both the currency risks associated with future long-term payment schedules and the average price per kWh generated, it could have a negative effect on cash flows for an off-taker such as ONE during the early years. This problem would be exacerbated when a number of IPPs are required to come on stream in quick succession. Planners, therefore, need to give adequate attention to the potential overall impact of IPP charges, especially when payment profiles are not uniform and are concentrated over the front-end of the contract.

5.4.5 Governance and Oversight

Electricity policy and *de facto* regulation in Morocco has always been centralised under the Ministry of Mines and Energy, although the Ministry of Finance is also involved in the setting of retail tariffs. It may be argued that it was the lack of independent oversight and governance that contributed to the system failures of the 1980s and early 1990s. On the other hand, from 1994 to 2004, , without *de jure* regulatory oversight, it appears that the power sector performed relatively well with the ushering in of private participation at the generation and distribution levels, the progress made with rural electrification, and the turnaround made in ONE's financial and technical performance. It could be inferred that in the absence of a regulator, there have been fewer regulatory hurdles for private investors, and tighter coordination with respect to power sector functions (since ONE was for all practical purposes the only actor IPPs had to deal with as it assumed responsibility for nearly all procurement and contracting functions), and this paved the way for the unfettered progress that was made during this period (CED pers. com. 2006; JLEC pers. com. 2006). As for the power projects developed, the absence of an independent regulator appears to have had little effect. All stakeholders interviewed involved in the development of the projects describe the tendering and procurement processes followed as fair and transparent. In terms of regulatory involvement during the tendering process for IPPs, it is not clear, therefore, whether the presence of an independent regulator would have further reduced the prices or changed the purchase conditions of the power provided by the IPPs, which won their bids through competitive tenders. Once the agreements were finalised, the IPPs had long term contracts in place and were 'regulated' by the conditions of their contracts.

It is in the period after 2004, however, where the lack of oversight and necessary remedial action may have contributed to the financial deterioration of the utility and an increasing shortage of domestic electricity generation capacity. While the utility has done well to grant electricity access to almost all its rural population, in so doing, it has generated strong demand for power. The pace at which generators were added did not keep up with the increasing demand, partly because of difficulties with the environmental concerns of plant locations, and concerns over primary energy availability and security as previously mentioned in section 5.2.3. In addition, the mismatch between the tariff structure and increasing fuel costs has contributed to the poor financial state of the utility as events unfolded between 2005 and 2008. The effects of these outcomes may have been reduced had an independent and credible regulator been involved in the tariff setting process providing oversight of power sector planning and implementation.

5.5 Conclusion

This chapter has illustrated that Morocco's experience with power sector reforms appears to be mixed. During the earlier years, from the mid-1990s until 2005, this sector developed quickly in addressing its problem of insufficient capacity despite a bold electrification access programme. Morocco's private power innovations have registered successful outcomes. Reliable and relatively affordable power is being supplied, and investors appear to be satisfied (CED pers. com. 2006; EET pers.com. 2006; JLEC pers. com. 2006), with some signalling interest in further investments, provided conditions remain favourable. At the country-level, much has been done to help diversify Morocco's electricity supply in the aftermath of the droughts. Although having no significant resources of its own, Morocco has established itself as the energy link between Europe and Africa through the 400kV interconnection with Spain and the gas pipeline. Through both these means, Morocco has been able to satisfy its energy demand simply through its proximity to Europe and its neighbour's abundance of energy resources. This has enabled Morocco to increase its diversification not only of its primary energy through EET and the gas pipeline, but also adding electricity as a final product, through the transmission links that Morocco has with Algeria and with Spain.

Since 2005, however, the country does not seem to have been able to keep up its initial momentum to the point, in 2009, where it was expected to import more than 10 per cent of its electricity needs. Political and environmental issues have delayed the development of plants and have resulted in an increasing gap between domestic supply and demand, the largest in the ESI's post reform history. Insufficient emphasis was given to environmental acceptability

and fuel security during the planning phases of the projects, resulting in delays in getting the much needed generation capacity on line. This indicates that planning needs to include environmental risk assessments, fuel security and financing to ensure that generation capacity comes on line timeously. While greater capacity interconnections with Spain means that Morocco can import more electricity and make up for the shortfall, this is a medium term solution to deal with the long standing problem of insufficient domestic generation capacity. In 2005, for the growth trajectory experienced from 2004 to 2007, the government planned to have an installed capacity of 6230 MW, nearly 1000 MW more than what was available (Berzard 2005). This deficit between actual and planned capacity (compensated for by imports) is indicative of the difficulties the county has experienced since 2005 in contracting and developing adequate generation infrastructure despite the state's desire to be less dependent on its neighbours for power imports.

ONE's financial situation has deteriorated since 2004 and it is expected that without a significant improvement, this could suppress investor appetite for further IPPs.¹⁸⁵ This is likely to be the case if a low tariff environment is sustained while costs continue to escalate.¹⁸⁶ Some analysts have predicted an electricity crisis in Morocco in 2009 and 2010 if immediate steps addressed at financial sustainability and energy security are not implemented urgently (Agence de Presse Algérienne 2007).

The absence of a credible governance and regulatory framework with the objective of establishing financial equilibrium in the sector has also contributed to the sector's fiscal dilemma. Greater oversight of key sector indicators could have highlighted potential problems well before the crisis by analysing risks future generation projects may face in the sector, modelling risk scenario trajectories, and assessing their impact on the power sector at large. In the absence of institutions dedicated to fulfilling these functions, it is probable that the problems of capacity shortages in Morocco will persist.

¹⁸⁵ Although the government ultimately wants more private sector investment in generation, it can still action ONE to develop further generation capacity additions, as a supplier of last resort. With external debt levels having come down, from more than 110 per cent of GDP during the mid-1980s to around 30 per cent in 2005, the pressure for private financing is considerably less, giving the government more flexibility in a strategy to finance generation infrastructure from its own accounts.

¹⁸⁶ Although there has been an increase in tariffs, it has been insufficient to cover increasing costs; in line with the social role that electricity plays, below energy inflation increases have been approved in Morocco (Boushaba 2007).

Morocco's early IPP experience shows that generation planning, procurement and contracting functions can be adequately undertaken by the incumbent state-owned utility (i.e. ONE), provided that the SOE itself is reformed and is operating effectively. But has Morocco's more recent experience underlines, these planning, procurement and contracting functions can be far from optimal when the SOE itself is experiencing financial and operating difficulties.

As long as hybrid arrangements are not accompanied and serviced by more adaptive frameworks that better respond to their challenges, certain aspects of power sector planning, governance and contracting will continue to undermine the objective of sustainable power sectors that execute adequate and timely investment in generation.

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CHAPTER 6

POWER SECTOR REFORM IN TUNISIA

Tunisia is a rare case in Africa. In this North African country, power sector reforms to invite private participation in generation, were instituted despite the national utility showing a healthy performance in both technical and financial areas of operation. The emerging hybrid market arrangements in the Tunisian ESI appear to have been managed well and have facilitated investment in generation infrastructure. The power sector has seen few institutional reforms and remains vertically integrated with only one large scale IPP supplying approximately 20 per cent of national production.

Power sector planning has remained with the SOE utility and planning in the Tunisian context is sufficiently flexible to cater for evolving market conditions. Tunisia's energy sector illustrates that the ability to adapt to changing conditions is facilitated by the use of power generation technologies that are: relatively quick to construct; are less prone to having environmental risks and other causes of delays; the availability of low cost fuel; strategically sound DSM programmes; and transmission networks which are integrated with that of neighbouring countries.

In Tunisia, international competitive bidding practices for the procurement of large scale generation infrastructure is mandated by law, and procurement oversight is provided as part of the legal framework. The utility benefits from a credible tariff regime supported by the state to ensure financial equilibrium in the power sector. Its good performance track record has contributed to its providing of the most affordable electricity in the Mediterranean and North African regions.

In summary, the Tunisian power sector has been able to adequately respond to the challenges of the hybrid arrangements, creating sufficient certainty for potential investors and facilitating new private and public investment.

6.1 Introduction

Starting in 1987, the Tunisian government, with support from the International Monetary Fund and the World Bank, engaged in a series of structural reforms, covering nearly all aspects of the country's economy. One of the main arms of this reform programme included a privatisation initiative, with respect to certain government controlled industries and state-owned enterprises.¹⁸⁷

Although the government sought to open up the economy to increase efficiency, privatisation did not mean the absence or elimination of government. The goal was, and continues to be, to create a partnership between public and private institutions, reducing the state's direct involvement in certain industries, but maintaining state control of policy formulation and regulation.¹⁸⁸ Specific attention was given to reducing the state's debt burden, which had been steadily increasing during the early 1980s, as well as shifting the burden of skills development and training to private entities, a cost that had been carried almost wholly by the state until then (Tunisian Privatisation 2004).

Under the reform programme, privatisation presented itself in a number of different forms in the manifold sectors of the Tunisian economy.¹⁸⁹ In the hydrocarbon sector, private exploration had been present for many years. When the power sector was opened in 1996, IPPs were the first manifestation of privatisation participation. The country's first IPP was developed under a Build-Own-Operate (BOO) framework and included a long-term PPA with

¹⁸⁷ These reforms covered nearly all the functional domains of the economy and included, amongst others, economic regulation, fiscal policy formulation, price controls, foreign trade and investments and banking and financial systems. Legislation for the privatization programme was enacted by law no. 89-9 on 1 February 1989. This was modified by law no. 94-102 on 1 April 1994, law no. 96-74 on 29 July 1996, and law no. 99-38 on 3 May 1999, and was completed by law no. 2001-33 on 29 March 2001 (Tunisian Privatisation 2004).

¹⁸⁸ Public companies to be privatised were defined as companies where government held at least 50 per cent direct interest. By 1994, 46 of the 189 public companies that had been earmarked for privatisation were completely or partially privatised either through issuing shares or through the sale of assets, and, by 2005, more than 160 state-owned enterprises had at least been partially privatised.

¹⁸⁹ These forms included: selling active business units within a larger company; selling a percentage share of the entity (with government retaining the remainder); selling shares in the business and listing on a stock exchange; mergers and take-overs; and, finally, granting the right for private generators to sell electricity to the state-owned utility (the means through which IPPs would be developed).

the state-owned national utility, Société Tunisienne de l'Electricité et du Gaz (STEG). The second IPP was developed as part of the country's hydrocarbon framework. The hydrocarbon framework sought to attract exploration companies to the power sector by allowing them to sell to STEG electricity produced from gas that had previously been flared. Although both IPPs use natural gas as primary energy, the two projects vary in size, fuel supply arrangements, power purchase agreements, and the legal frameworks under which they were developed. With Rades II, the country's first IPP, loans were indexed to multiple currencies and, to date, charges to the utility remain affordable. This is partly due to the fact that the Tunisian dinar (TND) has been relatively stable since the inception of the contracts - unlike in other emerging economies where currency devaluations have resulted in significant increases in charges. With El Biban, the country's second IPP, fuel supply problems have interrupted production for extended periods, impacting on overall plant performance and revenue. While the loss in revenue obviously threatens the financial viability of the plant, impact on the off-taker, the national utility, has not been significant for the following reason: El Biban represents less than 1% of the country's installed capacity with no guaranteed availability in terms of its contract with the off-taker. Nevertheless, the plant is crucial in understanding Tunisia's overall experience and is particularly relevant to other countries throughout Africa, which have developed, or plan to develop, power plants as part of larger gas infrastructure projects.

This chapter explores Tunisia experience of attracting generation investment, and is structured into three parts. Following this introduction, the next section provides a brief description of the Tunisian energy sector, particular, the electricity supply industry. It also examines the reforms undertaken towards liberalising this sector of the economy. The section which follows describes the two independent power projects that have been supplying power to the national grid since power sector reform started, and the contractual agreements that have been reached by the various stakeholders. The last section discusses some of the key elements that affected reform outcomes as they relate to the problem of insufficient investment in generation infrastructure.

The information presented in this chapter draws on structured literature searches, followed by a country visit and detailed interviews with key stakeholders in the Tunisian ESI. Interviews and written queries were conducted with eight stakeholders throughout 2006 in Tunisia. Interviews were followed by numerous correspondences to clarify discussion points up until the time of producing this thesis in 2008. Stakeholder interviews included representatives from the Ministry of Industry and Energy, Société Tunisienne de l'Electricité et du Gaz (STEG), Carthage Power Company (CPC), Société d'Electricité d'El Biban (SEEB) and

academics from the Faculty of Economic Sciences and Management at the University of Tunis. Due to the sensitivity of data, stakeholders have not been identified by name and are only identified in the text by organisational affiliation.

6.2 The Tunisian Electricity Supply Industry

Electricity production in Tunisia started in 1930 and by the time of the country's independence in 1956, seven private companies were producing and distributing electricity, with the country boasting an installed capacity of 100 MW, comprising of four water turbines totalling 27 MW and a number of dispersed diesel plants (STEG 2006).¹⁹⁰ These seven companies were nationalised in 1962 to form one electricity company responsible for the generation, transmission (including importing and exporting) and distribution of electricity and gas. This consolidation brought about the establishment of the national utility Société Tunisienne de l'Electricité et du Gaz (STEG), which was granted exclusive rights for generation, transmission and distribution of electricity (UNDP 2004).¹⁹¹

From 1962 up until 1996, STEG, which remained a publicly owned company, was the sole entity allowed to provide electricity services – this excluded self-generating plants which in 1962 constituted less than 1 per cent of the country's installed capacity. In 1996, through law no. 96-27, the state authorised private investors to generate and sell electricity to STEG.¹⁹² It was the 1996 legislation that opened the door to Rades II - the country's first IPP.¹⁹³ The country's second IPP, El Biban, came through a different door. As indicated in the previous section, in addition to luring exploration companies to the country's hydrocarbon sector, the Hydrocarbon Law of 1999 also permitted gas extraction companies to operate gas-fired power plants without a bidding procedure and to sell the electricity generated to STEG.

¹⁹⁰ Some references cite that there were eight companies but it is believed that two of these companies had one owner.

¹⁹¹ Nationalisation decree, bill no. 62-8 of 3 April 1962, which was subsequently ratified by bill no. 62-16 of 24 May 1962, outlined STEG's position as exclusive provider of electricity and gas.

¹⁹² The detailed terms and procedures for the granting of rights to private generating companies were laid down in ordinance no. 96-1125 of 20 June 1996.

¹⁹³ Rades I, commissioned in the 1980s, is owned and operated by STEG and is situated in the same industrial zone as Rades II.

Despite these steps to open up the electricity market, little unbundling has occurred in the utility. STEG remains a vertically integrated state-owned utility, albeit with separate accounting systems for generation, transmission and distribution, respectively. Separate accounting systems have also been cascaded down to different business units within the utility.¹⁹⁴ Furthermore, it is unlikely that supplementary substantial sector reforms will be introduced with respect to unbundling in the short to medium term. With the relatively small size of the market coupled with the apparent lack of compelling drivers for such reforms, no significant benefits for the sector can be seen at present (Ministry of Industry and Energy pers. com. 2006). It should be noted in this context that STEG is a commercially viable and technically efficient utility, as will be described further in Section 6.2.1 below, and not dependent on the state for financial aid.

6.2.1 Generation

In 2007, Tunisia produced 13146 GWh of electricity, with hydro and wind accounting for 0.5 per cent and 0.4 per cent of production respectively. The remaining generation was from fossil fuels. Natural gas accounted for the bulk thereof.¹⁹⁵ Although a net energy importer, most of the fuel used for power generation is produced from Tunisian sources. IPPs represented just over 15 per cent of installed thermal capacity in 2007, but accounted for roughly 22 per cent of Tunisia's electricity production in 2007 (STEG Annual Report 2007:10). The installed capacity in Tunisia totalled 3 313 MW in 2007. Of this total, only 2.4 per cent was from renewable sources, which comprised 62 MW of hydroelectric power plants and 19 MW of wind farms. The majority of the country's installed capacity is, therefore, in the form of thermal power stations. Table 6.1 below lists the installed capacity in Tunisia in 2007.

¹⁹⁴ The same applies for the gas divisions within STEG.

¹⁹⁵ It is estimated that in addition, self producers generated approximately 776 GWh or 5.9 per cent of national production (STEG Annual Report 2007:10). Self producers comprise mainly generation controlled by the Tunisian phosphate industry, which sells excess capacity to STEG (Ford 2004).

Table 6. 1: Installed Generation Capacity in Tunisia

Plant	Capacity (MW)
STEG Thermal Plants	2734
STEG Hydro	62
STEG Wind	19
IPP - Rades II	471
IPP - SEEB	27
Total	3313

Source: STEG Annual Report (2007:16)

STEG, an ISO-9001 compliant company, is generally considered an efficient state-owned enterprise and its generation plants are perceived to be well managed, with average plant availabilities in the order of 90 per cent. Efficiency improvements have been amongst the objectives in all areas of the utility's business over the last decade and results have been admirable, especially in the technical arenas. In addition to the technical improvements made over the years, the utility has managed to decrease its number of employees from 9487 in 2004 to 9249, a reduction of 2.5 per cent, while during the same period increasing its number of low voltage customers by more than 10 per cent or 250 000 customers (STEG Annual Report 2007:12-13).

Between 1997 and 2001, electricity consumption increased by an average of 7.7 per cent per annum (TERNA 2004). In 2002, the rate slowed to about 3.5 per cent, with similar growth recorded through to 2007. Although it was originally thought that IPPs would primarily respond to growing demand, since the development of the country's first IPP, state-sponsored plants have recently been on the increase. In addition, while the state is still committed to its policy objectives of opening up the economy, attracting private investment and limiting its debt in infrastructure projects, the Ministry of Industry and Energy and STEG have indicated that there is no plan to fix the percentage of privately contracted power, i.e. IPPs would be developed on a case-by-case basis. Relevant factors such as timing and fuel supply security, amongst others, would be important considerations in deciding on the sponsors of future plants (Ministry of Industry and Energy pers. com. 2006; STEG pers. com. 2006).

On 26 May 2003, the British Gas Group (BG) and the Tunisian government entered into a Memorandum of Understanding for the development of the Barca project, a 500 MW combined cycle gas plant (BG Group Press Release 2004). The Barca project was intended to use untreated gas supplied by BG to meet Tunisia's increasing power needs (Flin 2003:66).

Negotiations with BG stopped in June 2004, however, as a result of concerns related to the gas supply guarantee for the project. Due to time constraints, the government gave STEG the go-ahead to develop the next tranche of power generation.¹⁹⁶

A feasibility study was also initiated to build a 1200 MW IPP in the north of the country with approximately two-thirds of the capacity earmarked for export to Italy. Although this study is still in its infancy, should the results of the study prove positive, COD would be scheduled for 2011/2012. With an interconnection to Italy, such a project would go a long way toward strengthening the Mediterranean grid, enhancing links with neighbouring countries, and represent one more step towards a Mediterranean power market.

As part of its tenth development plan (2003-2007), the Tunisian government is also planning the construction of wind farms with a capacity of about 120 MW. The RfP is signed and bid evaluation was scheduled for early 2007. The country's eleventh development plan, for the period from 2008 to 2011, provides for the construction of a further 200 MW by private investors on a purely competitive basis (TERNA 2004).

As stated earlier, since the inception of the country's two IPPs, STEG developed all additional generation capacity. The utility has since commissioned gas turbines at the Feriana and Goulette power stations in June and July 2005 respectively (STEG Annual Report 2005:8,10). Following on this, STEG received authorisation to develop the 120MW expansion at the Thyna power station. In 2007, the Thyna expansion was commissioned, the Sidi Daoud Wind Farm was expanded to capacity with the addition of 35MW, and STEG initiated a bidding process to install a further 120MW of wind power in the Bizerte region. Further, STEG has completed a technical analysis for the realisation of a 400 MW combined cycle gas-fired plant at Ghannouch, with construction expected to start in 2009. Technical studies have also started for another base-load plant, which is scheduled for development around 2011-2012.

As recently as November 2008, STEG signed an agreement with the Islamic Development Bank to lend the utility TND 250 m for the construction of two power stations; one at Feriana in Kasserine with a capacity of 126 MW, and the other at Thyna in the Sfax region. Guaranteed by the state, the loan is over a term of 20 years with a three-year grace period.

¹⁹⁶ The bidding contractors to the Barca project would be Enelpower and Ansaldo Energia of Italy, and Alstom of France (Flin 2003:67).

In the expectation of an annual increase in demand of between 5 and 8 per cent (Agence Tunis Afrique Presse 2008), STEG has initiated a tender for a turnkey contract for a 380-450 MW combined cycle gas plant. At the same time the Ministry of Industry and Energy has initiated a tender process for the development of a 350-500 MW combined cycle gas plant to be operated on a BOO basis by an IPP (Ministry of Industry and Energy 2008). Mindful of its decreasing natural gas resources, the country has started the process of establishing a nuclear industry for power generation, with the construction of the first units scheduled for the period 2016 to 2023, and for operations to commence in 2024 (Kriaa 2008).

6.2.2 Transmission and Distribution

Tunisia has a well-developed electricity grid across the country, especially in the northern and central areas. The system is interconnected with Algeria and Libya at the 400 kV and 225 kV levels. On 29 June 2007, the Ministry of Industry and Energy signed a memorandum of understanding with the Italian Ministry of Economic Development with the aim of jointly creating a company to develop a transmission interconnection between the two countries, as alluded to in section 6.2.1 (STEG Annual Report 2007:23). Although the Tunisian network is already linked to the European network through the Algerian and Moroccan networks, this interconnection will strengthen the Mediterranean grid and bring further power exchange opportunities to Tunisia.

When the country's rural electrification programme was launched in the 1970s, only 6 per cent of the rural population had access to electricity. Emphasising rural electrification as a pillar for integrated rural development, education and improved health services, the government made rural access and electrification a top priority in its social and economic development plans (Cecelski, Ounalli et al. 2005:1). The distribution system has been expanded over wide areas to meet the national electrification goals, which has resulted in Tunisia being the top ranking country on the continent in terms of national electrification. The combined electrification rate (rural and urban) is approximately 99.5 per cent for the country's 10.5 million inhabitants.

The country's rural electrification programme went hand-in-hand with a DSM programme to curb demand, and despite the completion of the rural electrification programme, DSM initiatives continue. In addition to encouraging efficient energy use and creating awareness about the benefit of energy-efficient appliances, the Ministry of Industry and Energy launched a programme to promote the use of cleaner fuels such as natural gas and liquid petroleum gas

(LPG) as opposed to heavy fuel oil (HFO) and diesel. Co-generation schemes are encouraged and energy efficiency audits are conducted on large industrial users, which have helped to keep demand in tone. It should be noted that it is often difficult to accurately assess the effectiveness of such programmes, considering the myriad factors that impact on demand. However, given a decrease in the consumption growth rate in the last three years, despite robust GDP growth, there does appear to be evidence that DSM is having some impact. A 6 per cent increase in gas supply versus a 3.5 per cent increase in electricity demand may well indicate that there is a shift towards gas as opposed to electricity (STEG Annual Report 2007:30, 33). Of the most profound changes to reduce electricity demand has been the recent introduction of daylight savings in the country in 2007. The government has effected a change in the country's time stamp from GMT+1 to GMT+2 from March to October effectively shaving of 53GWh or 0.47 per cent of demand (STEG Annual Report 2007:8).

6.2.3 Fuelling the Tunisian Power Sector

During the last four decades, the energy sector has played an important role in Tunisia's economy. Throughout the 1970s, oil represented 50 per cent of the country's total exports, making a considerable contribution to financing social and economic development initiatives, as well as launching heavy industrial projects (Ministry of Industry and Energy 1999:35). Oil production did not, however, keep pace with energy demand. In 1999, to counter this trend, the government introduced the country's Hydrocarbon law, which specifies royalties of 10 per cent for oil and 8 per cent for gas to foreign companies for successful explorations. The aim was to attract foreign investors who otherwise overlook Tunisia, especially for Tunisia's energy-rich neighbours, Algeria and Libya.¹⁹⁷ A reduction in the tax rate from 75 per cent to 50 per cent for foreign firms has also been offered to lure investors, provided the state-owned oil company, Entreprise Tunisienne d'Activités Pétrolières (ETAP), takes a 40 per cent share in the deal (EIA 2004b). Despite these incentives to encourage exploration and increase domestic oil production, by 2000, the country became a net oil importer (Ford 2003). In 2005, it was estimated that Tunisia had a modest 1.7 billion barrels of oil reserves (CIA World Factbook 2008); in that year Tunisia produced around 75 000 barrels of crude oil per day, 37 per cent down from its peak of 120 000 barrels per day between 1982 and 1984 (Belloumi 2006).

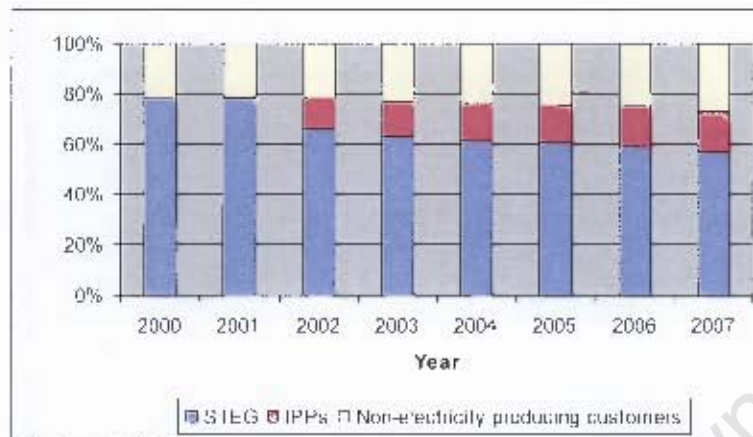
¹⁹⁷ Although operating on a smaller scale, oil companies from France, the UK, Italy, Germany, Hungary, Canada and Saudi Arabia amongst others are all currently active in Tunisia; furthermore, Tunisia has known private participation in its hydrocarbon industry since exploration first began.

Despite modest new oil finds, production in Tunisian oil fields continues to decline, and the country is increasingly turning to natural gas to feed its domestic demand. Tunisia has 2.8 trillion cubic feet (tcf) of proven natural gas reserves, and it is estimated that this constitutes 47 per cent of its fossil fuel reserves (Ford 2003; Belloumi 2006). The British Gas Group (BG), the largest single investor in Tunisia's gas-energy fields, produced around half of Tunisia's gas consumption in 2007 with the bulk of the remaining supply coming from Algeria (STEG Annual Report 2007:31).¹⁹⁸

An abundance of local gas resources coupled with access to gas from the Trans-Tunisia gas pipeline has helped shape Tunisia's electricity landscape in terms of fuel and generation technology choice, with most of Tunisia's electricity being produced from natural gas. In 1982 a gas pipeline connecting Algeria to Europe via Tunisia was developed and, in 1994, the export capacity of the pipeline was doubled (STEG 2006). The country receives between 5.25 and 6.75 per cent of the Algerian gas in the Trans-Mediterranean pipeline, which links Sicily with Cap Bon, in the north of Tunisia (Belloumi 2006:22). In 2003, Tunisia and Libya agreed on a plan to build a pipeline to transport natural gas from the Melitah area to the southern areas and industrial zone of Gabes in Tunisia. Although there has been a delay in the development of the pipeline, servitude royalties are expected to help Tunisia make up for future increases in demand. As of 2007, natural gas accounted for 98 per cent of all fossil fuels used in electricity production.

¹⁹⁸ BG has agreed to supply a large amount of domestic gas requirements for Tunisia through 2020 while expanding the Miskar offshore gas field in the south-east. This field produced approximately 41 per cent of the country's gas supply in 2007, in comparison with 2003 when it produced 65 per cent of the country's yearly gas supply. It is currently being expanded through several phases (Ford 2004; STEG Annual Report 2007).

Figure 6. 1: Gas Utilisation in the Tunisian Energy Sector

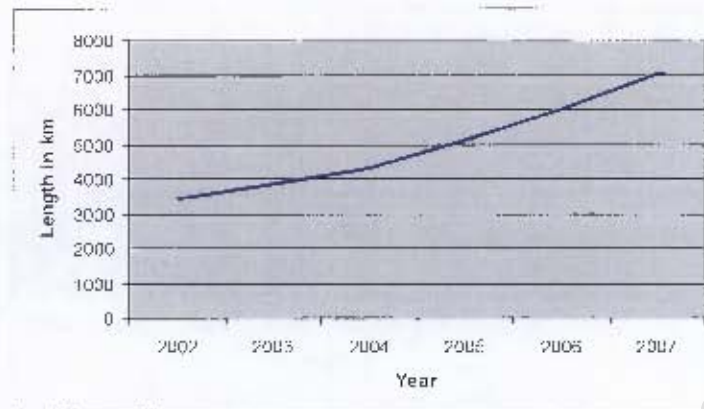


Sources: STEG Annual Reports

From the Figure 6.1 above, it is evident that less than three quarters of the gas supplied by STEG has been for electricity production in 2007, in contrast to 2001 and 2002 when nearly 80 per cent of gas supplied by the utility was used for power production.¹⁹⁹ This shows an increasing percentage of gas used as energy inputs by industry as well as commercial and residential consumers. STEG has actively been increasing its gas distribution network as evidenced in Figure 6.2. From 2002 until 2007, the utility has more than doubled its number of low pressure gas consumers providing the country with some degree of flexibility in switching between electricity and gas should pressure on electrical power reserves become severe (STEG Annual Report 2007:14). In 2007 alone, there was an 18 per cent increase in low pressure customers from 282 758 customers in 2006 to 332 967 in 2007.

¹⁹⁹ Industrial customers, public distribution and hotels account for the major users of gas amongst the non-electricity-producing customers. The numbers of gas customers have increased significantly from 121 234 customers in 2000 to 332 967 customers in 2007 resulting in an expansion in the gas network from 1633 km in 2000 to 7040 km in 2007 (STEG 2004b; STEG Annual Report 2007:36).

Figure 6. 2: Expansion of Gas Distribution Network



Sources: STEG Annual Reports

6.2.4 Tunisian Electricity Regulatory Frameworks

Tunisia has no independent electricity regulator, the small size of its electricity market is cited as one of the main reasons for this. Industry professionals, however, foresee that there may be a need for an independent regulator as Algeria, Morocco and Tunisia work towards an integrated ESI. In December 2003, these three North African countries signed an accord with the European Commission. In the Accord they propose to initiate plans by 2006 (which they have done) for a North African network that would eventually be integrated with the European Union (STEG Annual Report 2004:46). With an increasingly large and complex system, the need for an independent regulator to deal with regional exchanges and tariffs is thus expected (World Bank 2003b).

Although no formal electricity regulator exists, provision has been made for institutional oversight in the IPP legal framework, as will be discussed later in Section 6.4.2. The Ministry of Industry and Energy or its Directorate for Energy draws up plans for expanding the energy infrastructure and implements the energy policy adopted by the government.

Presently, the government is the de facto regulator with the Ministry of Industry and Energy determining tariffs based on proposals from STEG. In setting tariffs, the Ministry weighs the following factors: the financial viability of STEG; the requirements of lenders; inflation and the cost of living. Tariffs are broken down according to voltage level and according to the time of use for bulk industrial consumers. In the low voltage sector, the tariff structure has a progressive component to encourage the efficient use of electricity.

Unlike many other African countries, the Tunisian government has displayed a credible commitment to the financial sustainability of the power sector by allowing tariff increases on sound economic bases. In an effort to maintain sustainability, efforts have been underway to reduce cross-subsidisation and reflect the economic cost of power. Due to increasing fuel costs, there have been periodic increases over the last few years with two increases in 2005 and a 6 per cent increase in 2006 (STEG Annual Report 2006:8). Further escalating fuel costs have translated into two additional tariff increases in 2007: the first an increase of 6 per cent for electricity and gas in July 2007 and the second an increase of 6.9 per cent for electricity and 8.3 per cent for gas in December 2007 (STEG Annual Report 2007:8). Despite upward pressure on tariffs due to increases in fuel prices, tariffs remain low by European standards and within the African and Mediterranean regions.²⁰⁰

6.3 Independent Power Producers

Early in 1995, when broader macro-economic reforms, described in Section 6.1, were underway, the government conducted a feasibility study to assess the potential for private participation in the Tunisian ESI. The feasibility study was carried out by the IPP Group, a small team of high level managers from STEG, under the direct authority of the Minister of Industry and Energy.

This study concluded, within a few months, that IPPs may indeed have a favourable impact. As a result, the government's Structural Adjustment Plan, aimed at decreasing the budget deficit and especially the percentage of foreign debt, opted to include IPPs in its portfolio. The Ministry of Industry and Energy also posited that the introduction of private capital in the electricity sector would send a strong signal to the international investment community that Tunisia was committed to opening up its economy and liberalising its markets.

Losing no time, in June 1995, the government invited international investors to propose a range of projects. The ESI soon emerged as the most sought after sector, with 84 potential investors indicating interest. With the feasibility study, noted above, serving as a general

²⁰⁰ Tunisia's industrial and residential tariffs were seen to be competitive with those in Greece, Italy, France, Spain, Belgium, and Portugal, and also with those in Morocco and Canada (Toronto) (STEG 2004a; STEG Annual Report 2007).

framework, the IPP Group subsequently prepared pre-qualification and call-for-bid documents.²⁰¹

6.3.1 Carthage Power Company, Rades II

In 1997, two years after conducting the feasibility study, the Ministry of Industry and Energy launched an ICB to build the Rades II power station, a combined cycle natural gas-fired plant of 400-500 MW. A series of standard investment incentives were extended including: VAT and customs duties exemptions on all imported equipment that could not be sourced locally (pre- COD); and a 5-year tax holiday on companies' income tax (post-COD), which was to facilitate loan repayment. In addition, the government committed to support permit applications in order to minimise any potential delays on the project.

Seventeen consortia responded to the pre-qualification bid, which stipulated that the project consortium have extensive experience in the construction, project management, maintenance and operation of power plants. Sponsors were also required to be experienced in non-recourse project financing and have the capacity to finance the specified equity component of the required capital and raise debt financing for the remainder. Ten firms were short-listed, and in the final assessment, the following three consortia were retained:

- Public Service Enterprise Group (PSEG) (USA) / Marubeni (Japan) / Sithe (USA)
- National Power (UK) / Marathon (USA)
- Intergen (USA) / Endesar (Spain)

The selection criteria were based primarily on the price per MWh for which the electricity would be sold to STEG, over the course of 20 years. To ease the evaluation process, in the RfP for the BOO project, the Ministry of Industry and Energy specified acceptable interest rates, currency exchange rates, inflation rates, discount rates, fuel price and load profiles. This would later also facilitate bid comparison and adjudication.

The PSEG / Marubeni / Sithe consortium ultimately offered the lowest price per MWh, and the Ministry of Industry and Energy subsequently started negotiations with this triumvirate.²⁰²

²⁰¹ K&M, a US based consulting company with extensive experience in contracting private power, selected by tender from the short list were appointed as consultants to prepare pre-qualification and call for bid documents and assist the IPP Group during negotiations.

It should be added that each of the partners in the consortium had a good reputation for executing these types of projects as well as a favourable balance sheet to fund the equity component of the capital. The firms' technical, project and financial track records meant that they also were in a favourable position to negotiate rates with the lending financial institutions.

In March 1999, after seventeen months of negotiations, the project agreements were signed, and financial closure was reached in August of the same year. Total funding came to US\$ 260.7 million, with debt constituting 70 per cent of capital (Turki 1999).²⁰³ Soon thereafter, the Carthage Power Company (Pty) Ltd (CPC) was registered as the special purpose vehicle to develop the project. Although the targeted COD was for September 2001, the time lost, due to extended negotiations, meant that the plant came online eight months later than originally foreseen.

Delays may be partly attributed to issues related to land. The site where the plant was to be built belonged to the state and had been leased to STEG. Tunisian law specifies that equipment that is constructed on land belonging to the state falls under state ownership. Thus, in order to assuage lenders and investors alike against possible expropriation, a decree was issued, changing the land to the private domain, which allowed the sub-lessor (CPC) to grant rights on the equipment to the lenders.

a) Rades II: The Agreements

Like most African IPPs, the project was backed by a long-term PPA, which ensured that equity and debt holders would recoup the US\$ 260.7 million in addition to a favourable return, through the fixed capacity charge, tied to a minimum availability of 90 per cent.²⁰⁴ The 20-year PPA is front-end loaded with the debt paid off during the first ten years (although eight years after COD since repayment starts in the first two years of construction). All

²⁰² The second and third ranked bidding consortia were, however, kept on standby in the event of negotiations failing with the first.

²⁰³ The project agreements were signed on 24 April 1999 and came into force on 30 April 1999.

²⁰⁴ The charges may be broken into five components: 1) a fixed capacity charge linked to the plant's required guaranteed availability (of 90 per cent), which is how investors recoup their investment; 2) a fixed charge for the maintenance and operation of the plant; 3) a variable fuel charge that is a pass-through cost to STEG since the fuel is purchased from STEG; 4) a variable charge for the operating and maintenance of the plant; 5) other variable components such as insurance and start-up costs.

charges in the PPA are payable in Tunisian dinars, and are indexed to a basket of currencies proposed by the Tunisian Central Bank. Since the introduction of the euro currency in 2002, this has translated roughly into a 60:40 split in €/US\$ currencies.

The fuel agreement was simplified by the fact that STEG is the exclusive buyer and distributor of natural gas in Tunisia. With gas supplied by STEG, there are no take-or-pay obligations on the fuel and the costs are passed through to STEG in accordance with the governing agreements in the PPA (including that CPC is responsible for complying with the stipulated heat rates).

Provision was made for arbitration by Tunisian law at the International Chamber of Commerce in Geneva until the entire debt payment would be settled. Finally, an escrow facility is a requirement of the PPA; however, figures were not made public.

b) Rades II: The Stakeholders

The stakeholders in Rades II are numerous with changes noted in CPC since project inception. During construction, Sithe exited the project due to internal restructuring within the company.²⁰⁵ Thereafter the initial split between PSEG, Marubeni and Sithe of 35 per cent, 32.5 per cent and 32.5 per cent, respectively, changed. Sithe's shares were absorbed by the two remaining partners, and the arrangement changed to a 60/40 split between PSEG and Marubeni.

The Japan Bank for International Cooperation (formerly Export-Import Bank of Japan) JBIC, (40 per cent) and Banque Nationale de Paris and Sanwa Bank, BNP/Sanwa (60 per cent) were the lead lenders to the project, injecting 70 per cent of the project costs along with other commercial banks. ABB and Alstom won the engineering, procurement and construction contract for the supply and installation of the gas and steam turbines respectively (along with completion and output guarantees) and GE International was awarded an initial six-year maintenance contract for the plant.

In 2004, PSEG announced the sale of its 60 per cent shareholding in CPC to BTU Ventures, a regional energy investment group with financing from both public and private sources in the

²⁰⁵ A number of energy companies globally were restructuring during this period as they were consolidating their positions after negative IPP experiences at the time, partly as a result of the Asian and Latin American financial crises.

Gulf Cooperation Council states (PSEG Press Release 2004). BTU formed a joint venture with STEAG of Germany, an O&M service provider to form BTU STEAG O&M Services Company, which has taken over from GE and is now overseeing the maintenance and operating functions of the plant. Although offloading their position, PSEG described Tunisia as “an excellent place to do business” and confirmed that “the sale in no way reflects any unhappiness with [our] experience in Tunisia”, but rather is in keeping with the company’s “stated strategy of reducing its international risks by selectively selling assets if [we] can obtain an attractive price.” (African Energy 2004b).

6.3.2 Société d’Electricité d’El Biban

Rades II was not alone in changing the face of power in Tunisia. A second IPP, the El Biban Electricity Company, SEEB (Société d’Electricité d’El Biban) has also contributed, albeit on a much smaller scale. Although the plant only accounts for approximately 1 per cent of total generation, it provides several lessons in terms of fuel supply security and investor returns. It is also relevant to countries, such as Nigeria for example, seeking to commercialise stranded natural gas.

SEEB was the outgrowth of legislation enacted by the Government of Tunisia to encourage the development of marginal oil and gas fields by foreign independents for use in the power sector, for generating capacities below 40 MW.²⁰⁶ Within this framework, in contrast to the first, the Ministry of Industry and Energy agreed that a selective tender, rather than international competitive bid be conducted.²⁰⁷ Investment incentives extended were as follows: a five-year tax holiday, which was to facilitate debt repayment (to approximately five years); customs and import duties exemptions on all imported equipment and spares and VAT exemption. A further boon for all parties, but especially state actors, was that the project, by using previously flared gas, represented a significant environmental benefit. It is important to note that the SEEB plant runs only on natural gas. A significant modification would be

²⁰⁶ Marginal gas fields are defined as gas located too far from the gas supply network or where the quality is too low to be sold commercially. This initiative was spelled out in the Hydrocarbon Code law no. 99-93 of 17 August 1999 and amended by law no. 2002-23 of 14 February 2002.

²⁰⁷ IPPs developed through the 1999 Hydrocarbon law do not need to go through an ICB procedure as in the case of Rades II. This flexibility was favoured in the context of attracting exploration companies to prospect and operate in Tunisia and not as part of large scale capacity additions required due to national demand.

required to convert the plant to use an alternate fuel source; this stands in contrast to most of STEG's thermal stations, which can use an alternate fuel type as a back-up - the significance of which will emerge later in this chapter.

a) SEEB: The Stakeholders

The selective tender resulted in CME, a US-based energy company specializing in development, construction and financing of energy-related projects worldwide, being chosen as the initial developer for a 27 MW gas-fired plant. CME subsequently set up the BOO deal with Centurion Energy, an international oil and gas company, headquartered in Canada, and Caterpillar Power Ventures, as equity holders. Together these three firms developed the project - both power station and related gas infrastructure, including the pipeline to the well - for a total cost of US\$30 million.

Caterpillar was the EPC contractor through their Power Ventures group as well as the O&M contractor in the form of Energy Services International, a Caterpillar subsidiary created specifically to operate and maintain Caterpillar plants worldwide.

The US\$20.2 million debt for the project was split equally between ABS International Bank, a British lender with a Libyan majority shareholding, and Amen Bank, a local Tunisian private bank. The equity was split in the same manner between Caterpillar and Centurion Energy, giving each a 50 per cent shareholding in the project. Although CME was the lead promoter of the project, the firm does not have any shareholding in the project; when the ROR on the project exceeds 13 per cent, however, CME starts sharing in the profits. Finally, as with CPC, STEG is the exclusive buyer of the electricity generated.

As with Rades II, there has been some equity turnover. In September 2005, Centurion sold its share in the project to Candax, a Canadian based exploration company operating in the offshore El Biban and Zarzis oil fields.²⁰⁸

b) SEEB: The Agreements

The price of electricity in terms of the PPA was calculated as the avoided cost to STEG of producing the power and was indexed to the international oil price (low sulphur content heavy

²⁰⁸ The main reason cited for Centurion's withdrawal was to concentrate the firm's efforts on its Egyptian activities, not fuel supply issues.

fuel oil), but was capped at US\$130 per MT.²⁰⁹ The bottom limit was set at US\$99 per MT.²¹⁰ These limits, which correspond roughly to US\$19-25 dollars per barrel, were set in the wake of an announcement made by the Organisation of Petroleum Exporting Countries (OPEC) in 2002 stating that OPEC member countries would manage production so that oil prices would remain trading in this band (Guerbaa 2005:14). Early in 2002, during the PPA negotiations, the international oil price per metric ton ranged between US\$99 and 105 (or US\$19 and 20 dollars per barrel). With most of the costs of the electricity produced coming from operating the plant, energy charges are minimal. It was estimated in 2003 that profit after tax would earn Centurion approximately US\$1.8million per year with oil prices averaging US\$22.50 per barrel (Canadian Dollar Equities 2006).²¹¹

Other key terms of the PPA are as follows. The duration of the PPA is 20 years, depending on gas availability. In contrast to most IPPs, there is no guaranteed availability required in terms of the contract with STEG. Provision is also made in the PPA for arbitration, subject to Tunisian law in the International Chamber of Commerce in Paris.

By December 2002, the agreements had all been signed, including the power purchase agreement and the land lease agreement, and on 9 May 2003 SEEB commenced commercial operations.²¹²

c) SEEB: Gas Supply Problems

In April 2004, nearly a year after COD, problems arose with SEEB's gas supply. The gas was contaminated with hydrocarbon liquids, and the separators were not effective in removing the liquids from the gas to the specified humidity required by the plant hardware. This damaged the ejectors and resulted in degradation of the turbines, which, in turn, impacted on plant performance. Disputes between the gas supplier and the plant operator, regarding who was

²⁰⁹ Due to the confidential nature of the PPA, actual charges to STEG were not made known to the author. 1 barrel = 159 litres = 0.145 MT.

²¹⁰ This pricing formula was unique to SEEB and did not form part of a general pricing framework.

²¹¹ The gas price was fixed by the Ministry of Industry and Energy in a manner that both the gas provider (the gas previously flared) and project company may remain interested in the project. As a result, the outcome for the project company is still favourable despite the ceiling price for electricity produced.

²¹² The official inauguration was in July 2003.

responsible for removing the excess liquid from the gas, were resolved four months later when more efficient separators were procured and installed on the plant.

In August 2005, the plant came to a halt again when water entered the gas well and the gas could not be extracted. The new shareholder, Candax, initiated plans to drill two additional wells to alleviate the fuel supply problem. To this end, in May 2006, Candax awarded two contracts for the onshore and offshore engineering work of the El Biban redevelopment project. The scope included the fabrication of two new platforms and a modification to the existing platform. Despite the action by shareholders, there were, however, delays in bringing fuel production back within the scheduled timeframe. Among the many causes of the delays linked to procurement problems, a strong demand for exploration barges at the time meant that there was a long waiting list that Candax Energy had to join before being able to drill the wells; and when the work eventually started, much re-fabrication of work that originally failed to comply with the required safety and quality certification standards was required, delaying the return to production of the wells (Candax Energy News Release 2006). Meanwhile, SEEB has been out of operation since August 2005 and the wells were drilled only in the second quarter of 2008. For the time that the plant has been out of production no money has exchanged hands between STEG and SEEB, and the project has been unable to meet its scheduled loan repayment, which shareholders had to renegotiate with the project lenders (Candax Energy 2006). By the second quarter in 2008, the plant was still shut down, which means the plant had been out of service for nearly three years since it was captive to a single supply well.

6.4. An Analysis of the Hybrid Power Market and Outcomes in

Tunisia

The story of power sector reform in Tunisia, and the country's ability to commission generation capacity in a timely manner, generally appears to be more positive than the other three country cases examined in this thesis. This section analyses how Tunisia as responded to the changes of hybrid power markets.

6.4.1 Getting to the Hybrid Market Structure

Similar to the other three countries described in this thesis, Tunisia's resolve to reform its power sector was, for the most part, prompted by broader macro-economic policy changes with the objective of liberalising the economy and reducing the state's debt burden. Unlike

the ESI reforms in Ghana, Côte d'Ivoire and Morocco, however, poor performance of the national utility was not a factor influencing the decision to reform since STEG was a considered a well managed SOE exhibiting positive technical and financial performance.²¹³ The introduction of IPPs, therefore, was not specifically to improve the performance of the sector, but rather to assist the state in relieving its debt burden. Prior to private investment in generation in Tunisia's ESI, the state borrowed money and on lent these funds to STEG to develop generation infrastructure.²¹⁴ Since the reduction of the state's debt was a major objective of structural reforms, the decision was made to invite IPPs into the generation market as described in section 6.2.1.

What is also different to the other cases examined in this thesis is the two distinct ways in which IPPs can enter the generation sector in Tunisia; the first being as part of the country's IPP policy and the other, as part of the country's hydrocarbon policy. To date, however, only one IPP was developed under each of the frameworks and the country's power sector is still characterised by a dominant vertically integrated state-owned utility, with two IPPs entering on the margin.

STEG has retained major responsibilities and functions in the sector, such as planning. The responsibilities of procurement of IPPs, however, have been assumed by the state, through the IPP Group in the Ministry of Industry and Energy, although it is assisted by STEG in many ways. One other feature that differentiates the Tunisian ESI from the previous cases is the fact that the off-taker and national utility is also the exclusive provider of gas, the fuel used to generate almost all the electricity produced in Tunisia, including gas used for IPPs.

6.4.2 Power Sector Planning

Although privately-financed power was seen as the way of the future by many donors and policy makers worldwide, the Ministry of Industry and Energy was not overly ambitious in the early days of opening up the sector to IPP investments. The state and STEG retained the

²¹³ In terms of Rades II, public stakeholders have indicated that IPP charges are reasonable, and that had STEG built a similar project the rates would have been comparable (Ministry of Industry and Energy pers. com. 2006), meaning that STEG could have been equally efficient at developing and operating the Rades II power station.

²¹⁴ This is still a practice in the ESI. In November 2008 STEG borrowed TND215m (with a guarantee from the state) from the Islamic Development Bank for the construction of two additional power plants.

option of making further investments in generation. As an example, STEG could go ahead and develop the next power station after the government ceased negotiations with BG on the Barca project when fuel supply guarantees could not be obtained. Therefore, although Tunisia made a credible commitment to private participation in generation, it proceeded with due caution. To this end, despite policy and legal reforms preparing the way for the introduction of IPPs and taking away STEG's monopoly, STEG has retained the responsibility of power sector planning.

There has been almost seamless coordination between IPP sponsors, STEG and the Ministry of Industry and Energy.²¹⁵ In addition, having the fuel supplier and the power off-taker in the same utility also facilitated efficient coordination between stakeholders during planning and implementation phases. The fuel arrangements have also been instrumental in helping to reduce fuel risk and keep costs down. STEG is the exclusive distributor of gas in Tunisia and, therefore, was the only possible fuel supplier for the Rades II plant. It was agreed that the cost of the fuel would be passed through with no take-or-pay obligations (on either side) for the following reason. This arrangement has facilitated upstream fuel planning, not only because STEG is the only gas distributor in Tunisia and the supplier to all gas-fired plants, but also because it is the off-taker of the power generated.

Power sector planning has been performed in the context of the country's diminishing fossil fuel resources and its desire to decrease its carbon footprint. Within the Hydrocarbon IPP framework in which SEEB was developed, the Ministry of Industry and Energy has taken an explicit stance of limiting non-guaranteed IPP capacities to less than 40 MW, while at the same time encouraging investment in generation capacity and decreasing CO₂ emissions.²¹⁶

The expansion of the country's wind generation capacity has also meant that the country would be modestly less dependent on fossil fuels, as the rate at which renewable energies are expected to grow exceeds the rate at which fossil fuel power generation production capacity is expected to grow in the coming years. Lastly, nuclear power has been chosen as an option over the longer term to decrease its dependence on fossil fuels.

²¹⁵ The appointment of a former senior manager from STEG to the head of the IPP Group in the Ministry of Industry and Energy facilitated the coordination since he was well versed with the utility's processes and clear about the government's goals on private participation in electricity.

²¹⁶ The gas supply problems experienced by SEEB have also informed the government's negotiations on BG's Barca IPP, which would have used untreated gas for power generation.

a) Bringing Flexibility into Planning

A number of options are available to generation planners and the use of many of these options has helped to bring flexibility to the planning process. At the time of negotiating the country's first IPP, although the contracting process took longer than would have been the case if STEG had developed the Rades II plant, the utility was successful in maintaining a sufficient amount of generation reserves to overcome the delay (Ministry of Industry and Energy pers. com. 2006).²¹⁷ Also, despite the delays and subsequent cancellation of the Barca project, the planning was flexible and timely enough to initiate a process whereby STEG could develop the next capacity addition without eroding the country's generation reserve margins to critical levels.²¹⁸

Gas distribution network expansion projects have given the utility greater flexibility to switch between energy sources, i.e. electricity and gas, should there be significant pressure on the ability to supply either. In addition to doubling the number of gas consumers between 2000 and 2007, the expansion of the gas distribution network is still ongoing and, in future, will give more consumers the option to switch between electricity and gas energy sources. Moreover, good management of the country's electricity demand profile with the utility's other DSM programmes has meant that demand has been curbed giving the utility room for potential delays in developing future generation capacity.

Tunisia's geographic location has also contributed to its good fortunes in its ESI. In addition to having domestic energy resources, it is neighboured by two of the most energy rich countries in Africa. Unlike Morocco, relatively favourable relations with its neighbours have meant that it enjoys access to vast amounts of natural gas for power production. Not only does it have access to the gas, it receives royalties for a percentage of the gas that flows to Italy from Algeria and Tunisia's gas pipeline infrastructure is extensive, well developed, and linked to its neighbours to receive natural gas for domestic use, including non-electricity generation consumption. Having neighbours that are rich in energy resources has also translated into having neighbours that have adequate amounts of electricity for exchanges in the unlikely

²¹⁷ The legal concerns regarding the land for the Rades II project was the single biggest source of delay on the project.

²¹⁸ The delays that were experienced in private and not in public infrastructure investments also underlines how differences in public and private project development bring to the fore new challenges, especially for power sectors that are new to private investment and emphasises to the need for strategies to be flexible enough to accommodate such setbacks.

event that one of the countries experiences a shortfall; however, with STEG's conservative electricity planning the utility has had enough reserves to export to neighbours when required.

Not only has the country's proximity to Europe helped it to earn royalties for gas exports via Algeria, but it was also the trigger for initiating the proposed transmission link to Italy. Tunisia plans to be an exporter of power to the European transmission grid via the proposed link with Italy and STEG is poised to perform well selling power to the Italian electricity market since its tariff structures are competitive with that of the European Union. More importantly, the ability to supply power to Italy means that the country will have excess generation capacity, over and above what is needed to meet domestic demand. This will also give the utility greater flexibility in generation planning in the future.²¹⁹

Since the utility uses natural gas as its prime fuel source for electricity production, the fuel choice lends itself to power generation technologies that are relatively quick to develop, since gas-fired power stations of the sizes required for the Tunisian grid can typically be constructed within a relatively short period – typically in the region of 18 – 24 months. In addition to its short construction times, its high efficiencies and clean burning characteristics make natural-gas fired plants less prone to delays due to environmental issues. This technology and fuel choice, coupled with an extensive gas distribution network, has allowed Tunisia to be more flexible in its planning strategy to construct and commission additional generation. Even when negotiations for the Barca plant were suspended and the project halted, in a relatively short period of time, plans by STEG to develop the next generation capacity were easily fast tracked to avoid capacity shortages and ensure adequate generation reserves.

b) Project Planning and Risk Assessment

Although the SEEB IPP was developed under a framework inspired outside the power sector, viz. the hydrocarbon sector, and Tunisia has managed the risks associated with non-guaranteed power outputs by limiting the capacity to 40 MW, the project risks still hold lessons for countries planning to develop power sector projects using stranded gas, as previously noted. Project risks for the SEEB project were underestimated with regards to the fuel supply, and although the consequence of not being able to fuel the plant was small to STEG, for countries planning to develop similar projects as part of the country's main

²¹⁹ Transmission links with Europe not only allows for power exports but also for imports should the country experience a shortage of electricity.

electricity supply sources with relatively larger capacities, the consequences can potentially be devastating, for investors and off-takers alike. The fact that the gas for the El Biban power plant only had one source has surfaced as a latent weakness in the development of the project. The plant being captive to one single well meant that SEEB's financial viability was inextricably linked to the well's ability to feed the plant with primary energy – a risk that was probably underestimated.

With the gas supply compromised in 2005 and again from 2006 through to 2008, the outcomes have been less favourable than with Rades II. For investors, although there were no penalties payable to STEG for non-delivery of power, the absence of revenue means that there was no income for shareholder dividends or loan repayment, which has forced the project company to renegotiate its loans with its lenders. With respect to the state-utility, in addition to not receiving any power during the time that the plant was struggling with its fuel problems, it has not been able to take advantage from the lower priced fuel arrangement — as world oil prices have increased significantly since the parties reached settlement on the agreed rate.

Insufficient attention also appears to have been given to how the equipment would react to the fuel quality. More specifically, since El Biban could not effectively process the gas with the original separators, new stronger separators had to be installed. This led to a significant loss in revenue as the plant was shut down for a four-month period while the problems were investigated and the new separators were procured. Additional problems were caused by water entering the well and impeding gas extraction. Another area related to the project sponsor arrangements that may have contributed to the project related risks, is the role of the lead promoter. CME, although responsible for the front-end risk analysis, does not have any exposure to the project's losses. Instead, the firm shares only in its gains when the rate of return exceeds 13 per cent. The fact that there was a huge upside opportunity but insignificant downside risk for CME could help in explaining why fuel risk, which is at the core of the project, may have been inadequately assessed and mitigated against.

Off-takers of power in countries planning to implement similar arrangements using stranded gas, like in Tunisia, therefore, need to pay due diligence to project related risks and incentives, since in the hybrid market, various incentive arrangements could potentially hold different risks for stakeholders in public and private generators. Even if guarantees are obtained and penalties are in order for non-delivery of power, the consequences of power shortages due to a large scale loss of production at existing facilities could hold dire consequences for the economy and potentially could cause political and social unrest.

6.4.3 Generation Procurement

Although IPP procurement was vested in the Ministry of Industry and Energy, to facilitate the development of IPPs, as well as introduce a new level of transparency in the contracting of the new generation capacity, two new commissions were introduced. When STEG's monopoly ended on 1 April 1996, decree no. 96-1125 of 20 June 1996 stipulated that internationally accepted ICB practices should be followed for all new generation projects and oversight would rest with the Higher Commission for Independent Power Production, CSPIE (Commission Supérieure de la Production Indépendante d'Electricité) and its lower-tiered partner, the Interdepartmental Commission for Independent Power Production, CIPIE (Commission Interdépartementale de la Production Indépendante d'Electricité).²²⁰

The roles of the two commissions are summarised as follows: the CSPIE was an inter-ministerial body primarily responsible for selecting the winning bid for each IPP, based on internationally accepted ICB practices. The CIPIE was tasked with providing input for the preparation of terms of references and the issuance of tender documents together with the evaluation of bids. The CIPIE was also charged with following up negotiations and ascertaining the various incentives to be granted by the state on a case-by-case basis.

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.^{221 222} Both the CSPIE and the CIPIE, which were temporary commissions that operated up until all project contracts were signed, may be credited with what has been deemed a well

²²⁰ Since the law mandates ICB practices for infrastructure large-scale power sector procurement, unsolicited bids are not considered in the procurement framework. While the Barca project was negotiated between BG, the Ministry of Industry and Energy and STEG, an ICB for the procurement of the project would have been a requirement. A change to the legal procurement framework would be required to advance a large-scale generation project (more than 40 MW) in the power sector without an ICB.

²²¹ It should be noted that the IPP Group, as previously introduced, within the Ministry of Industry and Energy prepared the documents to be discussed by CIPIE and negotiated the project agreements under the supervision of the CIPIE.

²²² An additional need for these bodies is because STEG's contracts are subject to public tender legislation, which do not provide for long-term contracts.

organised and ultimately fair and constructive bid. As one illustration, the CSPIE and CIPIE working together with the Ministry of Industry and Energy and other government agencies, were responsible for arranging one of the critical elements of the PPA in the case of CPC, namely mitigating currency risk by ensuring that capacity charges were pegged to a basket of currencies.

A sound investment climate may, in part, be credited with attracting IPP investors. Despite the fact that the Rades II bid occurred at a time when private investment in generation infrastructure in developing countries was beginning to taper off, there were 17 tenders submitted for prequalification. This level of competition helped to drive down prices, resulting in more competitive charges for the IPP. As noted previously, power charges for Rades II appear to be competitive and availability seems to be relatively high. Due to more advanced technology and higher operating efficiencies, it has been estimated that the Rades II IPP could produce electricity at a bulk cost (excluding fuel) 20 percent lower than plants operated by STEG (Muller-Jentsch 2001:52). In 2003 it was reported that CPC supplied 20 per cent of the country's electrical power to STEG at a price of US\$1.54 cents per kWh, excluding the cost of fuel (OME 2003:21), which compares well with other similar plants constructed in developing regions.

The World Bank commended the Rades II independent power project, describing it as one of the best-managed projects at the time that the deals were negotiated (Halawi 2003; CPC pers. com. 2006; Ministry of Industry and Energy pers. com. 2006).

6.4.4 Contracting and Governance

As in the all previous country cases, IPPs are regulated by the contracting arrangements entered into with off-takers and/or the state. During the bid and tender procedures, there appeared to be adequate governance mechanisms put in place to ensure that bidding, tender, and procurement processes were fair and efficient. Once the contracts were signed, regulation was purely by contract; i.e. there is no independent regulator in Tunisia. While there are no hard and fast criteria for allocation of new build opportunities between IPPs and SOEs, outcomes with respect to the power sector's ability to meet electricity demand remain positive. A number of factors may play a part in deciding which entity will be allocated the opportunity to build future plant; these include the ability to raise finance, the cost of finance, the interest from IPP sponsors, and the timing of the projects. Since a number of factors play a part in the allocation of new build opportunities, decisions on public or private investment and

development of generation projects are done on a case-by-case basis (Ministry of Industry and Energy pers. com. 2006).

The sound policy and governance environment also contributed to the credibility that STEG earned as power off-taker in the IPP context. STEG is a well run public company with notable technical and operational efficiency. Since reforms in the power sector were initiated, the company has continued to register profits and enjoy credible government commitment with respect to tariff increases and support for its initiatives in the energy sector. This has gone a long way in attracting investors to the power sector.

6.5 Conclusion

The decision to introduce IPPs in Tunisia was prompted by broader macro-economic policy goals, in particular to reduce the government's debt burden. The introduction of IPPs appears to have contributed to these goals, namely helping to relieve the state of assuming more debt, focus limited state funding on social infrastructure,²²³ and attract foreign investment. More specifically with regard to FDI, the projects have helped enhance Tunisia's image internationally as an investment destination and demonstrated that the country is able to facilitate large privately financed infrastructure projects.

To recap, for Rades II, the bidding was based on a competitive tendering process with the primary consideration being the price per kWh. With ten short-listed bidders, competition helped drive down prices. Competitive tendering is a legal requirement in accordance with the country's procurement framework for large scale plant. Explicit bid and tender processes have therefore been put in place to ensure transparency and clarity in procurement and contracting processes.

In terms of the El Biban plant, it arose within a separate legal arrangement (namely, the 1999 Hydrocarbon law), which was to encourage the development of marginal gas fields by foreign independents, and also contribute to a reduction in gas flaring. No competitive tender was required, but STEG did specify that it would buy electricity only at a tariff indexed to the avoided cost of heavy fuel oil to STEG in the range of approximately \$19-25 dollars per barrel. The two major shutdowns have led to STEG not receiving power and the project not

²²³ This is evidenced in the growing middle class, a reduction in poverty levels and a marked improvement in a number of social indicators.

receiving revenue as intended. However, with the plant capacity at 27MW, less than 1 per cent of national installed capacity, this is not considered significant from STEG's perspective. The same cannot be said for the investors, who have had to renegotiate loan payments. Still, all is not lost. New investors have drilled back-up wells and there is an expectation of a reasonable return going forward.

In terms of the actual project performance, based on the analysis, it appears to be favourable in the case of Rades II and less favourably in the case of SEEB, where there is room to speculate that the partnering arrangements and project risk assessments may have been incomplete. Fuel security and quality for SEEB has been the Achilles heel of the project, which has the potential to inform other similar projects, particularly new gas-to-power projects in both East and West Africa.

In the Tunisian case, many factors have contributed to the country being able to adequately attract sufficient investment in generation; in addition to a relatively positive investment climate, these include a well functioning national utility, continuity in planning, a flexible planning regime that is responsive to changes in power sector circumstances – the use of power generation technologies that are relatively quick to construct and commission and are less prone to having environmental risks and other causes of delay; procurement oversight obligated by a legal framework; the availability of low cost fuel; and a tariff regime supported by the state to ensure financial equilibrium in the power sector.

CHAPTER 7

SYNTHESIS AND CONCLUSIONS

7.1 Synopsis

As has been illustrated throughout this thesis, the experiences of African countries in attracting investment and developing sufficient generation capacities are varied and complex. Despite power sector reforms and the implementation of policies aimed at increasing investment in generation, the challenges in attracting adequate investment on competitive and sustainable terms remain formidable. Private investment in generation was conceived within the broader framework of power sector reforms to assist and relieve state-owned utilities of the burden of financing new power stations – an undertaking that the balance sheets of many public utilities did not allow them to do. Although the private sector stepped in to assist, investment has not kept up with demand and many countries still face power scarcities.

Power sector reform has been widespread, although mostly not as deep as originally foreseen or intended. There have been attempts to improve the performance of state-owned utilities, new regulatory agencies have been created and private investment has been sought in the form of IPPs but nowhere in Africa do we find fully unbundled, privatised or competitive electricity markets as sought in the new standard reform model. Instead what has emerged in many developing countries has been hybrid electricity markets where the incumbent SOE has retained a dominant market position while IPPs have been introduced on the margin. The development of IPPs, as described in this thesis, has offered an important opportunity to critically evaluate and synthesise the lessons learnt by power sector reform in Africa and other developing countries, and to identify the specific challenges that have emerged in terms of attracting new investment.

This thesis has sought to investigate the challenges that SOEs and IPPs face in meeting the objective of providing adequate generation services to developing countries in Africa. The main questions have been to what extent the emergence of hybrid electricity markets have created new challenges in attracting investment into generation capacity in Africa; how policy, regulatory, and institutional frameworks have frustrated investment in generation; and how planning and contracting challenges have contributed to the problem of insufficient generation capacity in Africa. The dissertation has further considered how to respond more effectively to these challenges faced by hybrid electricity generation markets.

This final chapter has three primary goals. Firstly, it gives a brief recap of IPP investments in the countries as described in this thesis. Secondly, it integrates the analysis of power sector reform, IPPs and the challenges of attracting new investment, from each of the case study countries in the previous chapters. By contrasting experiences across the different case study countries, general conclusions are drawn around the specific challenges that arise from hybrid power markets in relation to attracting new investment and how these challenges and problems might be overcome. Lastly, the thesis returns to the overall theoretical framework employed in this thesis (first introduced in Chapter 2), and seeks to extend the frontiers of our understanding of the ontology of hybrid markets with relation to the conundrum of insufficient generation capacity.

7.2 A Recap of Country IPP Experiences

In this thesis, detailed reviews of eight projects in four countries have been completed. Although the number of projects is small, it represents half of the installed IPP capacity in Africa. In addition to the eight studied IPPs that were actually commissioned, descriptions have also been given in the empirical chapters of plants that were planned, negotiated and sometimes partially developed, but which did not enter into operation as planned. An example is the Western Power IPP in Ghana, which went all the way to the completion of the construction phase of the project without the plant producing a single megawatt. The SIIF Accra and AES Sirocco IPPs in Ghana, as well as the Barca IPP in Tunisia, stopped short of closing agreements being signed between stakeholders. Further examples of problematic investments include the Cap Ghir and AlWahda plants in Morocco which are still in the planning stages.

Two of the eight plants investigated in detail in this thesis were commissioned but never fully developed in their entirety, despite having entered their operational phases. These were the Takoradi IPP in Ghana (where on-going 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 existing IPP plants were delayed in their development. 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 Ghir 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 on and off the cards since 1966.

In the countries that were studied, only 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 ordered to curb the rolling blackouts experienced in the country during the droughts of the 1990s, but which never produced power due to later improvements in the hydrological conditions in the country. 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 has imported sufficient power from Spain to avert load-shedding. Lastly, Tunisia has been successful in maintaining adequate generation reserves, despite BG's setback in developing the Barca IPP.

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? 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?

The following sections analyse the factors that contributed to the countries' capacities to attract adequate generation, and how they have converged to bring about the diverse outcomes in each of the power sectors. These sections describe the experiences of governments and project sponsors in each country and propose what they could have done differently, in certain cases, to achieve more promising outcomes. It therefore considers both past and future possibilities.

7.3 An Analysis of Factors Contributing to Insufficient Generation Capacity

A common theme that emerges from the analyses in the previous case study chapters is the failure of many hybrid power markets to deal effectively with timely and efficient procurement of new power. A number of functions which used to be undertaken by the state-owned utility now “fall between the cracks” and are either neglected or performed inadequately. This section discusses the generation planning, procurement and contracting challenges that emerge in hybrid markets.

7.3.1 Generation Planning in Hybrid Markets

The purpose of explicit planning in the generation power sector is to develop clear strategies to guard against both over-capacity and under-capacity. Over-capacity can result in consumers paying for generation capacity they do not need, whereas under-capacity can result in consumers not being supplied with adequate quantities of electricity. Given that there are a multitude of forecast inputs required for generation planning, coupled with the number of hurdles that have to be successfully negotiated even before a power station is constructed, the potential for getting planning wrong is significant. Many who operate at the decision-making level are often confronted with optimal generation plant mix decisions, as well as problems related to securing adequate financial resources for investment, realigning tariff structures to accommodate generation expansions, and negative consumer reaction to the upward adjustment of tariffs. Despite these challenges, generation expansion planning remains essential.

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 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. Power sector policy reforms resulted in IPPs coming into the market so that private investment could supplement 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 precisely and additional 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 – but then new, explicit processes would need to be put in place to procure private investment. Consequently, generation planning in the power sector has been elevated to a level of complexity different to that utilities were used to a few decades ago before power reforms were initiated.

a) Evolving Planning Frameworks

The experiences in planning of generation in the four cases have been diverse. In Ghana, power sector reforms brought about a change in planning accountability when the VRA no longer had sole responsibility for planning and the 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, since its establishment. 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 take development beyond this phase. Administering project proposals, initiating tender processes and awarding contracts to successful bidders of generation infrastructure providers does not fall within the ambit of the Commission's stated functions. As a result, planning, within the scope of the Energy Commission, has not been extended to include preparations for ensuring that financial, legal and environmental requirements will be met. 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 planning and execution functions in developing generation projects.²²⁴ Although the Ministry of Energy facilitates the development of generation projects, the project planning processes for additional generation plants has seen the involvement of the VRA, ECG and the Ministry of Energy since all three entities have undertaken commitments to enter into PPAs with private generators. In addition

²²⁴ An example previously stated is the Energy Commission's Strategic National Energy Plan which has Ghana's first unit of nuclear power scheduled for the year 2018, allowing only five years for project preparation and another five years for construction. In addition, the planning document does not describe how financing of generation plants will be realised.

to a lack of coordination between these organisations, in the absence of clear and enforceable rules for project procurement, each entity is left to follow a procurement route that roughly suits its own preference. This leaves the door wide open to irregularities and inconsistencies in the procurement process and impacts on the efficiency and timeliness of generation procurement.

In the case of Côte d'Ivoire, planning remained with the EECI when the utility handed over the management of the operations to a private operator. The same departments that had been responsible for planning in the EECI evolved through the reforms to take the form of SOPIE, and, to a lesser extent, SOGEPE, when the EECI was dissolved and the sector's new institutional arrangements established. Unlike Ghana, planning, therefore, remained with a specific entity. In part, this was facilitated by the specific form of private participation introduced in Cote 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. It was the first country in Africa to procure an IPP and followed this milestone with the successful procurement of a second IPP. Cote d'Ivoire 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.²²⁵

Since hardly any institutional reforms occurred in the power sector in either Morocco or Tunisia when IPPs were introduced, there was little change of responsibilities and planning remained with the national utilities. In Morocco, despite the utility no longer being solely responsible for new generation, it assumed responsibility for translating planning into bidding and procurement processes for IPPs. As a result, planning functions that extend through to the

²²⁵ A cost effective option is to complete the steam phase of Azitio since this would not require additional fuel resources (and the plant design has been completed for more than a decade). The Ministry of Mines and Energy has therefore engaged the shareholders of Azitio in talks to complete the steam phase that was planned at the outset of the project's development. The state is also in discussions with CIPREL to expand its capacity by adding a steam phase since this would be a more affordable option (for similar reasons to that of Azitio's expansion). In addition to these, other longer-term thermal and hydro generation projects are also currently being planned by the Ministry of Mines and Energy. For the time being, however, there is still sufficient generation capacity available.

commissioning and operational phases of projects have largely remained intact. 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.²²⁶ Under the BTO framework (as opposed to BOT arrangement) in Morocco, the utility is the owner of the generation assets despite private operation of the plant. All large scale generation assets, therefore, belong to the state, and this may have resulted in less jostling for market share (in terms of ownership) and more willingness and commitment by ONE to ensure that developments continue without unnecessary delays.

The data suggests that power sectors that have transferred their generation planning functions to new institutions risk experiencing new problems in ensuring timely and effective procurement of IPPs. It would seem that the propensity for certain aspects of planning risk being missed or falling through the cracks increases with extensive reforms (and subsequent reshuffling of responsibilities among sector institutions), especially where insufficient consideration is given to how the planning, procurement and contracting processes will unfold under the new institutional arrangements. The Ghanaian case is, therefore, a good example of how institutional frameworks and planning arrangements have not responded adequately to the needs of the hybrid market. It should be noted that the frameworks were instituted with the intent of being adapted to the standard model of reform (i.e. a fully unbundled, privatised and competitive market) and not a hybrid arrangement as found at present. However, instead of a transition step towards the standard model, the hybrid model has become the reality and perhaps even the 'end state'. It is clear that hybrid markets present very specific challenges with regard to generation planning. 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 – even though some of these may require new space for IPPs.

²²⁶ It should be noted, however, that the positive experience in Morocco has been somewhat tarnished by delays in environmental permits and also fuel supply problems.

b) Flexibility in Generation Planning

Power sector planning requires a degree of flexibility to make provision for unexpected issues which can emerge and delay the provision of electricity services. Contingency provisions are, therefore, retained as options to assist in periods when setbacks challenge security of supply.

In Ghana, the 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 countries included in this thesis. 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 may hold greater potential for increased investment. A more focused and systematic approach would serve to dislodge the 'hit or miss' perception amongst private investors. Potentially, negotiating with numerous IPP sponsors could have brought flexibility to Ghana's project planning and development processes, since a significant delay or cancellation of one project could have been compensated for by fast-tracking another project. However, it probably did more harm than good to the country's reputation as an investment destination for infrastructure since more projects were cancelled than were developed thereby sending an unfavourable signal to the investment community.

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 started the tendering process for the country's second IPP and exported surplus capacity to neighbouring countries, a strategy that Tunisia will also 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 *coup d'état* brought significant political uncertainty to investments in the power sector, giving it some breathing space to regroup and craft a more informed strategy, one that took into account the changing circumstances around future investment decisions. This not only ensured generous capacity reserve margins without the problem of stranded capacity (due to the high regional demand in West African states), it has also brought in much needed hard currency for Côte d'Ivoire, reflecting favourably on its foreign account. The transmission links between neighbouring

countries and Côte d'Ivoire have played a role and given some flexibility in generation planning, without the hangovers generally associated with over-capacity.²²⁷

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 are expected to be in excess of 12 per cent in 2009, after the strengthening of the interconnection. The reason for this record increase in power imports is due to other planning problems (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).

The most favourable of the four cases, Tunisia, has been able to exercise relatively prudent planning. Prior to the country's power sector reforms, Tunisia appeared to have fared well compared to the other three countries in this study, possessing adequate generation capacity to meet electricity demand. Well aware of the fact that private investment would be a first for the country, the utility made sure that it had sufficient generation reserve capacity in the event of potential delays in the contracting process. When the contacting process took longer than anticipated due to issues over land rights (and the rights of equipment on the land), the utility dealt with the delay without any adverse consequences with respect to electricity supply provisions to the country. Many countries take longer than expected to procure their first tranche of private capacity (mainly due to inexperience in private contracting) and Tunisia did well to have the foresight to cater for this by having adequate reserves before contracting its first IPP.

In addition to the reserves, transmission links with neighbouring Algeria and Libya meant that Tunisia had added defences against the risk of insufficient capacity since it could import power from its neighbours, if needed. Tunisia also has domestic natural gas to fuel its power

²²⁷ 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. Planning, therefore, needs to take cognisance of the context in which the function is to be executed. 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.

stations and has access to the gas networks of its neighbours. Since Rades II was developed, the country has extensively 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 to procure generation capacity, allowing the utility greater ease with lower generation reserves than if electricity had been the only large scale source of commercial energy. The natural gas also guided the generation technology choices of the utility and, since natural gas plants have the shorter lead times for development and commissioning of generation capacity, it puts the utility in a less challenging situation than those utilities 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 can be achieved in various ways and countries would do well to consider all options as resources to allow more flexible planning strategies. Flexibility, however, only buys power sectors time and planning frameworks cannot escape the necessity to be underpinned by sound fundamentals which will allow large scale expansions to be timeously developed.

c) Project Planning and Risk Evaluation

In hybrid markets, project planning and appraisal is often left to newly formed institutions that lack the capacity to execute these functions effectively. In some case, these institutions inherit functions for which they do not have the human resource skills (financial, legal, environmental, and engineering) to conduct adequate risk assessments during the planning and appraisal phase of the projects' development.²²⁸ Even where the same institutions retain the planning functions, a lack of proficiency can lead to inadequate risk assessment, especially when certain aspects of the project are new. This is often the case when projects are initiated by private sponsors and subsequently negotiated with the government and the off-

²²⁸ Governments and off-taker utilities often leave project appraisal to consultants, private sponsors of IPPs, and negotiators, all of whom may have different incentives to close the deal. This is particularly the case when upside opportunity incentives are significantly overshadowed by the downside risks. In the case of Tunisia's SEEB, for example, CME, the lead promoter of the project, shared in the earnings from the deal once the earnings exceed a certain rate of return, but did not share in the losses. Given that the hybrid market increasingly makes use of private investors who are often represented by negotiators whose incentives may cause them to be swayed towards failing to see potential downside risks, risk recognitions and evaluations should be incorporated in the off-takers' planning frameworks .

taker utility, which have less knowledge about the technology and potential drawbacks. In many cases, the urgency with which power is required also contributes to risk evaluations being hurried and inadequately performed.

In Ghana, while the Takoradi II IPP had sponsors with considerable experience in developing IPPs and operating power stations, the same cannot be said for the Western Power IPP which was built without generating a single kWh. The main project sponsor for the latter was the state-owned oil company, the 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.

Although one of the main sponsors of Tunisia's second IPP, SEEB, had prior experience in the development and operation of IPPs, the kind of project, where off-shore untreated gas which had previously been flared was used for power generation, was new to the sponsors as well as to STEG. It is often assumed that fuel risk can be mitigated by having the fuel supplier take a stake in the project since it has a greater incentive to see the project succeed in the absence of fuel guarantees. It is, therefore, also ironic in Tunisia's case that having the fuel supplier as project sponsor did not lead to favourable outcomes with respect to fuel availability and a loss of generation for the plant. In the cases of Western Power and SEEB, it could well be that because the fuel suppliers were project sponsors, it was taken for granted that fuel risks as part of the projects would be addressed.

The Western Power and SEEB IPPs were not the only projects described in this thesis where upstream fuel issues effected outcomes. During the earlier years of the operating life of Takoradi II, there were problems with fuel availability and quality, lowering the expected output from the plant. Although resolved when the fuel specification was changed, these problems contributed to insufficient generation capacity. 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.

These examples draw attention to the importance of the capacity needed for project appraisal in all facets of generation projects and demonstrate the potential for lapses in risk

management in critical components of the projects and how they can contribute to the problem of insufficient generation capacity.²²⁹

d) Demand Side Management Planning

Institutional coordination and agreement in dealing with the problem of insufficient generation capacity has been shown to be poor in the cases of Ghana. In Ghana, the fact that 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, is indicative of the obstacles faced in coordinating the DSM strategy to systematically deal with the problem of insufficient generation. For the DSM programme to have proceeded smoothly, agreement was required from the EFG, the Ministry of Mines and Energy and the Ministry of Finance. During this time, the country was in no small way bearing the burden of power shortages.

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, ONE, and local municipalities – and this, 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.

Thus 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

²²⁹ A further example is the difficulties experienced in developing the Cap Ghir and Al Wahda plants in Morocco, which underscores the importance of coordinating planning with environmental objectives and fuel supply guarantees from an early stage in the planning process.

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.

7.3.2 Generation Procurement

Procurement of generation infrastructure requires specified processes to be followed to optimise procurement costs and the total cost of the acquisition, to minimise opportunities for corruption, and to make plain the rules of the game to stakeholders involved. Procurement can be a long process spanning a number of years and, hence, efficiency and transparency are key determinants in the timely acquisition of generation capacity. Delays or irregularities in the procurement process can result in delayed construction and commissioning of power plants, exacerbating the problems of insufficient electricity generation. Efficient and transparent procurement frameworks are, thus, pivotal in the acquisition of new capacity, and the manner in which procurement is conducted has the potential to attract or discourage investment and commissioning of generation, as is elaborated in the section below.

a) Procurement Procedures and Adherence

Procurement of new generation capacity generally needs to be done in accordance with established rules and regulations governing procurement opportunities, bidding and awarding of contracts. A lack of guidelines for how funds are to be spent can lead to a number of problems in procurement. Equally distressing is the non-adherence to policies and guidelines since this can also lead to a number of problems, as evidenced in Ghana. Here, despite a policy of contracting large infrastructure projects through international competitive bidding (ICB) procedures, no ICBs have been launched for any generation projects developed; to date, all generation projects have been initiated through negotiated deals, despite the country's procurement policies favouring competitive tendering. Failure to adhere to domestic policies creates the impression of inconsistency within government departments and such behaviour may prompt investors and lenders to withdraw from deals, further contributing to the problem of insufficient capacity. Non-adherence to procedures can result in problems for investors even when it is the state that does not follow its own prescriptions as evidenced in the

example with Faroe Atlantic which lost its arbitration case against the Government of Ghana for non-payment of services (see Section 3.5.3).²³⁰

Part of the problem may be the number of actors that are independently involved in the allocation of opportunities for IPPs. 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. It may be argued that the number of possible off-takers in Ghana has contributed to the problem with each entity following a process deemed adequate for their purposes, and with little regard for national procurement procedures. In the relative absence of enforceable rules and accountability on the part of the off-takers in executing the procurement function, many potential IPP sponsors have engaged directly with an entity that it feels comfortable with, to propose and negotiate a possible IPP. The other part of the problem is the lack of governance around procurement where no external regulatory agency enforces procurement rules on utilities and the state. While the Ghana Public Procurement Authority has been established to set standards for public procurement in Ghana, it appears that this body has insufficient authority to enforce these standards on the power sector.

The extent to which countries are consistent in applying their policy prescriptions can attract or deter private investment, and inconsistencies, as evidenced in the case of Ghana, make investors wary of generation investments in countries where procurement standards are blurred and their adherence and enforcement arbitrary.

b) The Influence of Development Finance Institutions and ICB Benefits

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, where

²³⁰ To recap, in the case of Faroe Atlantic Company from the UK, the Ghanaian government entered into a PPA with the firm to provide additional capacity. Although the Ministry of Finance represented the Ghanaian government in the deal, internal parliamentary approval had not been sought by the Ministry of Finance, despite this being a requirement for such large-scale projects. On Faroe's court action, the High Court first ruled in Faroe's favour the sum of US\$6.3m plus interest. The government then appealed, but the case was dismissed by the Appeals Court leaving the government with the bill for damages. When the government appealed to the Supreme Court on the basis of the legality of the transaction, the Supreme Court ruled in favour of the government based on its obligation to uphold the constitution (and the laws of the country). The Supreme Court ruled that the agreement was unenforceable due to lack of mandatory parliamentary approval and concluded that the absence of parliamentary approval rendered the contract null and void.

competitive bidding is not required under the country's hydrocarbon framework. Apart from SEEB, all the projects examined in detail in this thesis in Côte d'Ivoire, Morocco and Tunisia had loan assistance from development finance institutions. Nearly all development finance institutions have clearly stated lending conditions for the procurement of infrastructure projects to which they provide financial assistance. The World Bank, for example, makes additional financial assistance available to countries that have difficulty in meeting the pre-conditions for accessing finance to help them to establish the required procurement 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 creation of quasi oversight institutions such as the CSPIE and the CIPIE gave credibility to the contracting process and allowed for a number of stakeholders to review and provide input to various aspects of the procurement process. These temporary institutions were credited with including the mechanisms for mitigating the currency risks in the Rades II deal by indexing the capacity charges to a basket of currencies rather than a single hard currency.

Development finance institutions have embraced competitive tendering since it promotes fairness and transparency and generally attracts more affordable charges. In Tunisia's case, it has laid a sound foundation for future private investments and demonstrated that the country is able to execute efficient procurement of large and complex private infrastructure transactions. 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 gauge the attractiveness of the power sector to investors by investor responses to tenders, by stipulating general criteria for plant requirements, they gave potential sponsors the opportunity to develop innovative and affordable ways of meeting these requirements. In the case of Côte d'Ivoire, the government set the range for the turbines for CIPREL at 75-105MW allowing more companies to compete

in the bidding process, and facilitating the achievement of lower power charges in the PPA.²³¹ The involvement of the World Bank also determined the procurement procedures for Azito, the country's second IPP, when the ICB method of contracting 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 where, after the deal was finalised, it was decided that the full energy charge should not be passed through to consumers due to the elevated cost. Furthermore, the government's insistence on buying the remaining 50 per cent shareholding from TAQA suggests that a much lower charge could be realised under different (more transparent and competitive) circumstances. 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 time when it is much needed, 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. A change in ownership from private to public, thus, allows the state to review the contract terms and reduce power charges (Awuni 2007).²³²

c) 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 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 practice effectively 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 reduced internal rates of return and lower project costs lower returns on equity, including local sponsors who may introduce a new wave of domestic private investment in power generation. Although IPP sponsors may be pre-selected for

²³¹ Competitive bidding also allowed CIPREL to attract reputable EPC partners and put downward pressure on the price of a kWh.

²³² The government was unhappy with the contract signed during the reign of the National Democratic Congress government under President Rawlings, which guaranteed CMS a monthly energy charge of US\$3m, irrespective of whether the energy was used or not (Awuni 2007).

strategic reasons by governments and off-takers, pre-selection could exclude other potential sources of investment.²³³

d) Allocation of Generation Investment Opportunities

No country examined in this thesis has ruled out state sponsored investment in generation and SOEs still remain an option to expand generation capacity. In all of the country cases, except for Tunisia, the main driver for private investment still persists: SOEs lack sufficient finances to fund additional expansion. Private investment will, therefore, continue to play a crucial role in the development of additional generation infrastructure. The countries examined in this thesis, however, lack clearly stated criteria for allocation of investment opportunities. Having clear criteria for investments can help to develop a more predictable environment for investors, thereby making investment processes more transparent and bringing credibility to decision-making processes. Investors are expected to react more favourably to such an environment and this, in turn, could facilitate further investment.²³⁴ The random allocation of generation opportunities to private sponsors and SOEs exemplifies the reality that criteria for private or public investment under a hybrid arrangement are lacking.²³⁵

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 Ghanaian government's diatribe against CMS for not allowing it first option to take over the remaining shares in TICO may be perceived as hostility towards foreign investment in the power sector, and a preference for domestic or state ownership.²³⁶

²³³ As an example, it is reported that domestic sponsors have indicated interest to participate in Morocco's generation sector through IPPs (EET pers.com. 2006).

²³⁴ Certain investors, for example, would only enter a market if there were an opportunity for increased market share and growth.

²³⁵ Such guidelines may not have been necessary had the sector been able to evolve into the standard model since different factors would have largely determined which entities would be allocated investment opportunities. However, when power sector reforms were instituted in the 1990s, it was not foreseen that the sector would still be in a 'transition' state.

²³⁶ In the case of Ghana, the country has a long history of hostility toward foreign investment dating back to the time of its independence when its first president, Kwame Nkrumah, who did not want Ghana to drift into neo-colonialism, fervently followed ideals of non-alignment and Pan Africanism, thereby promoting economic nationalism and reducing dependence on foreign technology, material

In Morocco, the country's next renewable energy project, a wind farm, will also be developed by the national utility despite ONE not having the financial resources to invest in additional generation infrastructure 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 their absence might deter such investment.

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 clear 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.

7.3.3 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: the length of the contract makes it possible for the sponsor to regain their investments and service debt with long tenors; conversely, in an environment of liberalisation, both parties can

goods and capital (McLaughlin and Owusu-Ansah 1994). Although subsequent leaders later adopted policies that allowed foreign investment and ownership in state assets and economic sectors, these generally followed as a result of a lack of alternate available options to pull the country out of its economic problems. The difficulties in successfully implementing privatisation policies and transfer assets to foreign investors in various strategic economic sectors such as transport, water, telecommunications, and power, supports the belief that that this economic nationalism has propagated to modern day business in Ghana (Decker 2008). This is in stark contrast to the francophone countries included in this thesis, which did not make such significant attempts to revise colonial legacies, but, rather, to build on them (Ali and Wahabi 1995).

encounter problems with fixed long-term take-or-pay contracts if the various conditions under which the contracts are agreed upon change.²³⁷ Whilst all contracts between IPPs and utility off-takers in this thesis 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 frameworks which shape the degree of predictability and governance in the sector, ultimately impact on the manner and extent to which investment is facilitated in generation infrastructure.

a) IPP Charges and Payback Periods

The ability to keep power charges from IPPs competitive has an impact on a country's ability to attract more investment and is, therefore, linked to the problem of insufficient generation capacity.²³⁸ In addition to competition *for* the market to put downward pressure on the price per MWh, the structuring of power charges, the ability to attract cheaper finance and keep interest payments low are all factors that have played a role in making private investment in generation more sustainable. Lower power charges resulting in lower tariffs to consumers make IPPs more acceptable to the public, especially when coupled with service improvements. By having lower power charges, the likelihood of stresses on contracts between IPPs and off-takers decreases. This sub-section illustrates how IPP contracting arrangements have impacted on IPP charges, and how the ability of off-takers to service these charges connects with further investment.

In the case of Ghana, a number of factors contributed to the relatively high power costs of Takoradi II IPP. TICO was a 100 per cent equity investment and, thus, had no debt to reduce the total cost of capital from the 20.5 per cent return on equity asked by the project sponsors. Disagreement on the power charges asked by the sponsor, CMS, for the additional steam phase to be developed also concomitantly delayed the completion of this phase which would

²³⁷ The ushering in of liberalisation may render long-term contract clauses burdensome to off-takers since they could force them to uphold non-competitive and uneconomic obligations at a later stage when prices (determined by demand and supply as well as other market factors) decrease. With long-term PPAs, prices are determined and locked in for an extended period. In a study of IPP contracts under stress conducted by Covindassamy (2005), *all* contracts under stress in Africa were related to regulation and price issues. Sociopolitical and macro-economic issues were additional causes for the stresses on the projects that were evaluated.

²³⁸ Lower IPP power charges are easier for off-takers to service and require lower consumer tariff increases. Adequate tariff increases help off-takers to stay afloat financially, making it easier for them to attract more investment.

have reduced the average cost of power.²³⁹ Additional factors that contributed to increased charges in local currency were the deteriorating currency exchange rate coupled with dollar denominated revenues for the investor and rising fuel costs paid for in hard currency. In a hybrid market, an accumulation of factors can easily make the contracting commitments burdensome. Stakeholders, therefore, should attempt to find ways in which contractual elements could be more flexible and less onerous on both sponsors and off-takers, such as grace periods on loans, as were negotiated as part of the contracts for Côte d'Ivoire's CIPREL and Morocco's EET.

IPPs in Côte d'Ivoire, Morocco and Tunisia have seen less upward pressure on power charges than was the case in Ghana. Low interest loans such the IDA loan that the Ivorian government secured from the World Bank and lent to CIPREL have also helped to reduce the charges by reducing the cost of debt on the project. Similarly, with Azito, the partial risk guarantee (PRG) from the World Bank for the loan syndication from commercial banks reduced the risks for commercial lenders, and the Government of Côte d'Ivoire posted a counter guarantee resulting in favourable terms for the loan agreements. Shorter pay-back periods have also reduced overall project interest charges with the large capital payments made during the early years of the loan repayments tapering off toward the later years until the end of the repayment period for the IPPs in Côte d'Ivoire, Morocco and Tunisia.

While shorter payback periods may reduce overall finance charges, when they are not synchronised with tariffs to service interest and capital payments on the debt of IPPs projects, this can result in cash flow problems for off-taker utilities. 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 low. When off-takers are experiencing cash flow problems, it is difficult to attract additional generation. Again, Morocco is an example of where three IPPs

²³⁹ While fuel makes up roughly 75 per cent of power costs in single cycle mode, the additional electricity provided by the steam cycle does not require fuel. For this reason, Côte d'Ivoire wants to expand its two existing IPPs to incorporate combined steam cycles (as opposed to building new plants). Morocco developed a combined cycle facility for the Tahaddart plant and decided on another combined cycle plant for the Al Wahda plant. In the same way, Tunisia decided on a combined cycle plant for the Rades II IPP.

were developed within five years, with collective payments to all IPPs reaching a peak at the end of year five.²⁴⁰

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 assistance. The whole experience of contracting IPPs is 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.

b) Regulatory and Governance Frameworks

The standard model of reform for the power sector would include an independent, transparent and credible regulator to provide oversight and to promote efficient and fair markets. It would also maintain tariff structures that cover the cost of electricity generation and provide incentives for further investment. Using private sector financing for electricity infrastructure requires good regulatory systems to protect the interests of both investors and users, and to ensure the long-term interests of the power sector. These requirements are equally important in hybrid power markets.

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

²⁴⁰ It was from this time onward (in 2004) that ONE did not register profits due to increasing charges from IPPs as a result of the debt payment profile on the projects, increasing fuel costs and low tariff structures.

significant role in the development of the IPPs included in this thesis. 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 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 sponsors.²⁴¹

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 objectives on a few occasions. Although PURC is legally mandated to be impartial in its operations, it is still dependent 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 more recent efforts to have cost-reflective tariffs by changing the tariff structure and increasing the band of the lifeline tariff (which consumers do not pay for). The resignation of the PURC chairman following this debacle 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 foregrounded short-term political interests ahead of power sector sustainability. Political interference has, therefore, hampered the regulator from discharging its mandate and

²⁴¹ While an *ex ante* review of the PPA may have led to continued negotiations to further decrease the charges, further negotiations would probably have meant prolonging the electricity crisis and continued load-shedding, a situation that the government probably wanted to avoid at the time (PURC pers. com. 2007).

undermined the role that PURC could have, and should have, played in bringing credibility to the power sector.

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, the finances and the technical performance of the sector. SOGEPE was established precisely for the purpose of managing the sector's finances and ensuring financial control in the sector. SOGEPE's crisp mandate of ensuring the financial sustainability of the sector within a broader 'regulatory' framework contributed to an increased focus on tariffs. Given the fact that financial equilibrium of the sector was the most important feature of the reforms in 1994, and again in 1998, this oversight function has helped the sector to give attention to a key aspect that had been neglected before 1990. Since the inception 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 included in this thesis. Thus the nature of the "hybrid" power market is very different in Cote 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. Thus the country has few of the contradictions which potentially arise in other hybrid market where the state-owned and managed national utility often plays a contradictory role. 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.²⁴² In addition, the priority payment order which allows private operators first right to revenues collected from consumers, and the fact that there are only private operators in the power sector, makes it harder for the state to sustain a tariff schedule that does not cover the cost of power production.²⁴³

The presence of three state agencies in Côte d'Ivoire does not create the same contradictions as in the case of Ghana since their roles are more distinct. ANARE acts as an arbitrator and mediator between actors in the sector, SOGEPE 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 in the power sector under its tutelage. The three entities in Côte d'Ivoire perform their respective functions under a different legal framework (where financial equilibrium is mandated as the most important sector priority). Unlike PURC and the Energy Commission in Ghana, where tariff setting and licensing is done by these two 'independent' institutions, licensing and tariff setting remain the prerogative of the state in Côte d'Ivoire, with the three institutions feeding into and coordinating these processes.²⁴⁴ In addition to Côte d'Ivoire's institutional and regulatory framework, therefore, the success with respect to power sector development, in part, continues to rely on the commitment and resolve of the state.

In Morocco, the absence of a regulator during the reform process does not appear to have impacted negatively on investment during the first decade since power sector started, i.e. from 1994 to 2004. However, the development of generation infrastructure appears to have been

²⁴² Having the state removed from day-to-day power sector operations helps to avoid conflicts of interest between it and potential private operators in the sector when IPPs want to enter the generation sector and state operators find ways to keep them out. As an example, the Ashanti/KMR plant described in section 3.2.2 did not materialise due to the VRA not allowing the sponsors to sell excess capacity on to VRA customers. The negotiations also failed because VRA wanted to charge a wheeling fee for the power that would make the project uneconomic for the sponsors.

²⁴³ This is in contrast to other power sectors where SOEs are dominant as operators in the sector and may, therefore, be neglected when political considerations by governments to keep tariffs low takes precedence over economy and sector sustainability.

²⁴⁴ For example, licences are issued by the Ministry of Mines and Energy, not SOPIE. In the same way, tariffs are set by the Ministry of Mines and Energy, not by ANARE or SOGEPE.

inadequate for the period commencing in 2005, as tariffs have not kept up with the cost of production, thereby creating financial troubles for the national utility, ONE. While the utility has done well to grant electricity access to almost all of its rural population, in so doing, it has allowed the demand for power to increase significantly due to the new connections and, in part, low tariffs. The pace at which generators were added did not keep up with the increasing demand. It is difficult to draw conclusions on the how the absence of an institutional regulator impacted on outcomes or on how the presence of a regulator would have influenced the final result. However, it is suggested that, with greater oversight and effective governance systems and institutions, many of these problems may have been avoided or the impact thereof may have been reduced.

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 financial equilibrium in 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 equilibrium and economic considerations.

Tunisia, on the other hand, has seen consistent tariff increases reflecting the increasing cost of fuel and power production over the last three years (until 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, thereby making it possible for it to meet the state half way with respect to the financial sustainability of the sector. It appears that there was no resistance from STEG to incoming IPPs, as was evidenced in Ghana. 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. Strong commitment from stakeholders has contributed to successful reforms in this North African country that saw little resistance to reforms from public stakeholders. Belev (2000:1-14) has conducted an in-depth examination of political control of privatisation and economic opening in Tunisia. He posits that the success of privatisation and liberalisation in Tunisia, in general, is as a result of illiberal means of enacting economic reforms and the greater political control of the central government. He argues that the greater the political control of the central government, the smaller the scope for the involvement of

actors (such as bureaucracy, public sector managers, private sector investors, labour or other agents) to participate in the liberalisation programme. This reduces the likelihood that such agents will be in a position to derail the programme if their goals and interests diverge from those of the central government. He concludes by advocating that liberalisation programmes have a higher likelihood of success if political interference in the economy (which is served by the various aspects of sector reform) is reduced or eliminated, since it lessens the burden on the government to follow through with reforms. Tunisia is noted for its intolerance towards objectors of the government and its policies. While the country has done well to achieve a well-functioning power sector through the enactment of reforms that are perceived as progressive, it may well be that success achieved in the country's power sector liberalisation and reform policies are, to some degree, as a result of its disallowing broader engagement of stakeholders in the sector.²⁴⁵

To summarise, regulatory risk, as first introduced in Chapter 2 (Section 2.3.2), does not appear to have impacted adversely on projects that were successfully commissioned and examined in detail in this thesis. This is because the IPPs are regulated by their contracts and the contracts were agreed on before regulators came into being in the cases of Ghana and Côte d'Ivoire in West Africa, and because there have not been any regulators instituted in Morocco and Tunisia in North Africa. While there is an 'independent' regulator in Ghana, its autonomy and impartiality has been undermined by its financial dependence on the state which has meddled in tariff structures and adjustments on a few occasions. In Côte d'Ivoire, despite the regulator's limited powers, other oversight institutions in the sector as well as a credible sense of balancing finances has helped to sustain positive outcomes.²⁴⁶ In Morocco, the absence of an independent regulator does not appear to have adversely affected the country's ability to attract investment in generation in the early years of reform. More recently, however, with ONE having made losses for four consecutive years since 2004 and tariffs not having been increased to reflect the increased cost of production, it appears that sound fiscal governance has been lacking. In contrast, Tunisia has shown a stronger commitment to the financial credibility of the sector, understanding its implications for further investment in the sector.

²⁴⁵ Of the country's president, the Committee to Protect Journalists described him as a "dictator who has monopolized power for no less than 21 years. He runs Tunisia as a police state, where the country's large, Soviet-style press does little more than laud the despot and his tight-fisted regime" (Tunisia Watch 2008).

²⁴⁶ Since the coup d'état in December 1999, however, it has been difficult to collect enough revenue to cover the cost of capital projects due to payments from the rebel-controlled areas in the north of the country having ceased.

In all, the data suggest that while having independent and transparent regulatory institutions is important for the sustainable functioning of the power sector, commitment to regulatory and governance functions, regardless of whether these are separate regulators or embedded in the state, is more important to the sustainable functioning of this sector and the attraction of adequate investment in generation infrastructure. The case of Tunisia, which has probably been the most successful of all African countries in its IPP 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 an effective instrument in government realising that policy – for example in planning, procurement and contracting of IPPs.

7.4 Revisiting the Analytical Framework

To recap, the standard model of power sector reform was intended to introduce unbundling, privatisation and competition into the ESI, including the generation sector. Such competition was intended to drive down the price of power, which, in many state-owned utilities, was high due to a number of operational and financial inefficiencies. It was believed that corporate governance and investor oversight, as is prevalent in private generators, would encourage competence and efficiency, and that greater discipline would be applied to financial management. In addition, it was expected that the stronger profit motive in private investment would encourage more efficient investment in generation including in technology choices and timing of decisions. In all, private investment was expected to introduce a more efficient approach to generation planning and contracting, one based on sound market-based economic principles. State-owned generators, most of which were considered to be inefficient and lacking the financial resources for capacity expansions, would be unbundled, corporatised and compete against each other in this market. These developments would address the historically poor technical and fiscal performances that persisted in many African and other developing countries. The introduction of private capital through IPPs was seen as a convenient first step towards this market and could provide almost immediate relief to power systems that were short of capacity, since they could be introduced before actual market trading platforms were in place. The general notion that was widely held was that the private sector could procure and develop, maintain 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.

Although many developing countries in Africa and the rest of the developing world were sceptical about the appropriateness of the reforms in countries where the starting conditions were different to those in countries where reforms had been successfully implemented, with few alternatives available, many countries reluctantly proceeded in enacting reforms.²⁴⁷ While a few cautionary voices warned against the transferability of reforms and how their success was strongly linked to the contexts in which power systems found themselves, the reform message spread as it was advocated by development finance institutions, international policy consultants, and, in some cases, domestic champions. Legislation was enacted to make provision for the reforms, state-owned utilities were corporatised, electricity regulators were established, and institutions were revamped to allow closer alignment in order to deal with the drivers and achieve the objectives of reform.

7.4.1 Power Sector Reform and the Private Sector

In each of the countries included in this thesis power sector reforms were undertaken with the possibility of achieving the end state of the standard model, as was done by the early reformers, as first described in Chapter 2. While some have made profound changes to their power sectors transforming these in many respects, no country has achieved the end state of the standard model. Indeed, nowhere in Africa is a fully unbundled, private or competitive electricity market to be found. Power sector reform in Africa and in many other developing countries has resulted in what this thesis defines as a hybrid model in generation 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. As exemplified in the case studies in this report, the introduction of power sector reforms has brought in its own challenges to achieving an end state where power markets, private investment, price signals, and other mechanisms would facilitate investment in generation infrastructure and help deal with the problems of insufficient electricity. It is interesting to note that, globally, no country that had reached the end state of competitive markets has reversed its decision (Hunt 2002), which suggests that the functioning of the market itself, bar its imperfections, operates reasonably well and is sustainable. This is not to say that if, and when, developing countries

²⁴⁷ Many of the early reformers had capacity excesses, differing substantially from many countries in Africa, which had very different drivers for reform as well as little experience with private participation in public infrastructure. The most pressing driver at the time of reform in African countries has often been to fill the gaps with urgently procured power rather than providing benchmarks for state-owned plants and enabling long-term sector efficiency.

achieve the end state of competitive power markets it will be relatively easy to sustain power sector developments. The problem for many countries, however, has been how to get there; the journey towards competitive power markets appears to have encountered a number of obstacles that have prevented developing countries from reaching the end state. 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 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 (and distribution) has not been realised as intended by the PSRC. Even in Côte d'Ivoire that has hardly any state-involvement in the day-to-day operation of the utility, progress to the standard model has not been achieved. In Morocco, too, the implementation of a dual market proposed as a transition toward a competitive market, has seen delays. Tunisia has reverted to mostly public-funded plants operated by the national utility, STEG, after having developed only one large-scale IPP and finding itself in a different environment where the drivers for reform initiatives have relaxed.²⁴⁸

Given that, in all probability, competitive generation power markets will not be realised as intended, at least in the foreseeable future, a key question to be addressed is: How should power sectors reorient reform initiatives in order to achieve the benefits of initial reform objectives? Moreover, if the *de facto* situation is a hybrid market, how can they be made to work so that the original objectives of increased investment and more efficient operation are obtained?

The analysis of data collected for this project suggests that power sector improvements should focus on improving the conditions for continued and timely generation investments in the hybrid market. In many countries, since the ushering in of IPPs, national utilities are no longer suppliers of last resort and pre-reform planning and procurement frameworks residing with SOE utilities have been dismantled to make provision for new ones. In the absence of price signals for generation (as would be found under the standard model of reform), planning needs to be more carefully co-ordinated amongst institutions in the sector. It needs to encompass a wide range of functions (engineering, financial, legal, environmental) to adequately assess planning and project risks. Planning should be dynamic and reflect latest

²⁴⁸ The country's debt levels have declined since reforms were first instituted.

market prices. In addition, planning should be flexible enough to accommodate setbacks in project development. This planning function should be well resourced and equipped to deal with the intricacies and challenges of private sector investment as described in this thesis. Serious consideration should be given to individual contexts and conditions in the power sector. Special attention should also be paid to the commitment of governments to the institutions that will enable power sectors to realise these improvements as discussed earlier in this chapter.

Procurement and contracting should preferably be conducted by an institution that is independent of SOE generators – possibly an unbundled transmission company or system operator. The impartiality that this arrangement would provide would assist in minimising conflicts of interests between SOEs generators and potential IPPs. Clear and efficient bid and procurement rules should be developed for the acquisition of new capacity, and satisfactory oversight and enforcement over the procurement process is needed to ensure transparency and fairness.

Many of the above points might seem obvious. Yet, what this thesis has shown is that they are often neglected. Hybrid power markets give rise to new challenges. Many functions previously undertaken within vertically-integrated, state-owned national utilities now fall between the cracks. The over-riding insight from these case studies is that hybrid markets require explicit and purposeful policy actions to deal with the challenges of integrated planning, allocation of new-build opportunities, linkages to investment, internationally competitive bidding and robust contracting of IPPs; and clear institutional responsibility needs to be assigned for these functions.

7.4.2 State-Owned Enterprises

Mostly the above analysis has focused on the interactions between state-owned utilities and IPPs in hybrid markets and the planning, procurement and contracting challenges that have to be addressed. But the specific nature and functioning of the dominant players in these hybrid markets, namely the state-owned enterprises (SOEs) also needs to be examined. The development role of SOEs in economic sectors of developing countries is arguably more important than the role they play in the economies of their industrialised counterparts. Given the influence that governments have over their existence, SOEs are useful vehicles to assist developing countries address social and economic predicaments and backlogs. The fact that SOEs of all sorts have remained prominent, even in many industrialised nations (especially in

strategic infrastructure sectors), is indicative of the benefits that state ownership can have as governments influence the role of public enterprises in the various economic sectors. The problem occurs when the development role that the SOE plays comes at the expense of its operational and financial performance and threatens its own survival and sustainability. It is for this reason that various governance mechanisms were advocated during the first round of reforms, introduced in Chapter 2 (see Section 2.2.3.2). In many cases, electricity utility SOEs, due to their public service nature, have continued to be organs of social and political patronage.

In the case of Ghana, political control over the functions of institutions (regulator and utility) was evident when the government weakened the authority of the regulator, PURC, whose mandate it was to improve tariff structures and increase revenues for the ailing state-owned utilities. Despite the creation of an independent institution to administer tariff setting in a depoliticised environment, the temptation to interfere was too great for the government. This led to dissatisfaction on the part of the regulator and, in an outcry of frustration, the chairman tendered his resignation. For many years low tariffs have contributed to insufficient revenues for the national utility playing a part in its poor financial state. Technically bankrupt utilities find it hard to raise debt for, and attract investment in, infrastructure without state involvement and commitment through the issuance of securities. This has been a prime reason for the lack of adequate investment in generation in Ghana. With little support for the VRA in terms of tariff increases or securities provided by the government, the attractiveness of the SOE as off-taker was lacklustre.²⁴⁹

Apart from the political inclination towards shielding consumers from the rising costs of power and, in so doing, maintaining favour with the voting masses, it is widely alleged that the appointment of the former CEO at the national utility, the VRA, was politically inspired, rather than based on his technical and management competence in power utility operations (Ghana News 2002-2008). His relationship with the political elite afforded him considerable leeway in the management of the company, and he was eventually asked to resign after long disputes (resulting in industrial action in a campaign for his removal from office) with VRA

²⁴⁹ Weary of the difficulties that the VRA had in making timely payments for the power generated, TICO requested securities from the state for the development of the steam phase of Takoradi II during negotiations. Providing securities such as state guarantees was something that the government did not want to do. The sole security, therefore, would be the PPA, which terms the VRA was already having difficulty in meeting due to the fact that the utility itself was not financially self-sufficient but depended on the state for subsidies.

staff over his management style. The former CEO of the Ghana National Petroleum Company, the SOE responsible for the development of the Western Power IPP, was also described as ‘the right hand man’ of the former president and enjoyed considerable discretion in the management of the company, with weak operational oversight, governance and accountability (KNUST pers. com. 2007).²⁵⁰ Political appointees coupled with inadequate governance mechanisms to oversee and steer performance improvements in SOEs have contributed to insufficient focus on the operational and financial pillars that uphold and sustain an efficient ESI.

In Côte d’Ivoire, the state-owned utility also displayed poor financial and operational performance in the 1980s. However, the granting of a private concession and the two institutional reform reorganisations established in 1990 and in 1998, have contributed to improved oversight in the power sector, leading to enhanced performances.

The Government of Morocco encouraged tariff decreases between 1997 and 2004, but by 2005, electricity costs had risen faster than had been predicted mainly due to increases in fuel costs, charges from IPPs and electricity imports. Social and political considerations also played a significant role in the government’s push for universal access and low tariffs, while adequate governance arrangements to ensure financial stability in the sector and to minimise generation project risks to sustain adequate generation capacity has been lacking.

A different picture has emerged in Tunisia where governance arrangements have worked towards the achievement of the objectives of the state-owned utility, with STEG having been able to make significant improvements in the expansion of its electricity and gas networks, building additional power plants, and increasing its efficiency. The state has also demonstrated its support to the SOE by allowing tariff increases reflective of the cost of electricity production and, in so doing, displayed its defence of the financial and technical well-being of the utility.

Comparing the data from the four cases in this thesis, it is clear that government action demonstrating its commitment to public enterprises through allowing tariff increases, providing adequate governance arrangements, and enforcing accountability of SOEs, plays a

²⁵⁰ The weakened fiscal and operational state of other SOEs in the Ghanaian economy indicates that there was, in general, insufficient support given to SOEs to improve their performances and that adequate governance mechanisms to improve performances were lacking.

significant role in the ability of state-owned utilities to show positive performances. Positive performances enable public enterprises to act as credible power off-takers to IPPs or to self-invest in generation infrastructure and through raising debt in domestic and foreign bond markets.

In summary, SOEs can, and in many cases, should, be used as instruments of social advancement in developing countries; however, when political interests and considerations adversely impact on the SOE's ability to deliver services then the role of SOEs becomes problematic. In addition, when a government expects an SOE to operate in a manner that puts the utility's own well-being at risk, the relationship between the SOE and the state becomes problematic. It is the ability to strike a balance between development interests and SOE (and sector) sustainability, as well as make tough decisions when tempted to sway too much towards political interest that will determine the success of SOEs in advancing social and economic progress for African and other developing countries.

This analysis of the new challenges that arise in hybrid power markets has also highlighted the important role that the national utility continues to play and that in many cases it continues to make sense to allocate core responsibilities to the utility for national planning and the procurement and contracting of IPPs. In many cases, governments do not have this expertise, and powerful national utilities can assist or take responsibility for these functions. This means that the imperative of SOE reform and ensuring well-performing national utilities remains as important as ever. Tunisia is a good example of how the national utility has been an effective instrument in enabling the creation and operation of an effective hybrid power market that has responded to power requirements and delivered new investment. Tunisia may be a special case because of its political and cultural history. Nevertheless, the *de facto* situation in most developing countries is that SOEs remain important. In situations where these institutions are not as closely aligned to state reform objectives as Tunisia, or where they are ambivalent about the introduction of IPPs and a hybrid market, then more careful thought needs to be given to institutional reform, such as ring-fencing or separation of the system operator function which could become the home of the integrated planning, procurement and contracting function so necessary for the effective functioning of hybrid power markets. In assigning and designing these functions, effective governance will remain an imperative.

7.4.3 Crafting a New Reform Framework

Hybrid power markets are thus 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.

What the previous section has emphasised is that we have to recognise that 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.

For SOEs to perform well, there needs to be credible commitment from government to support their sustainability, and regulatory institutions and their functions need to be supported. In turn, there has to be accountability to the government by SOE managers and adequate governance mechanisms in place to provide oversight of their operations. In this way, SOEs can be steered towards practices associated with their development role without eroding their financial and technical integrity. The capability to attract IPPs, on the other hand, is dependent on a credible off-taker of power whose sustainability is supported by the government through the mechanisms mentioned above. Since the economic basis of any IPP is dependent on its ability to earn revenues from power off-takers (which are generally SOEs), the policy, regulatory and institutional frameworks need to be supportive of both IPPs and SOEs.

While the private sector is certainly needed to assist in plugging shortages in generation capacity, developments within the power sector should be aimed also at state-owned utilities being financially self-sufficient, with efficient operations and good technical performances. For SOEs to improve and achieve this level of quasi self-dependence and sustainability, each country will need to examine its policy, regulatory and governance frameworks and identify gaps and weaknesses. The interventions required to overhaul the power sector and create sustainability may involve broader macro-economic policy changes, which, in many cases,

are having adverse effects in economic sectors other than the power sector. It is acknowledged that the political costs of such interventions may be high for certain governments. Without these changes, however, neither SOE reforms nor private sector participation is likely to be successful in improving performance since both require strong commitment from ruling governments to bring about transformation in earnest.²⁵¹

Given the propensity for delays in generation projects in African countries, linkages between planning and implementation would require tightening, with governance frameworks providing oversight in these phases. Institutions responsible for planning should be adequately resourced for project evaluation to assess potential risks in project development, and management strategies should be directed at minimising delays in developing generation infrastructure projects.

Guiding principles should be in line with the possible, and likely, generation technologies that countries may opt for, their potential obstacles during implementation, and the financial aspects that may impede the development of the projects. Given, that there are many specific project-related and country-related factors that have the potential to stall project development and even to cancel projects, strategies to manage project risk would require some degree of customisation for each project in each country. Policy and planning frameworks, therefore, need to take cognisance of a range of issues – financial, environmental, social and labour - as they are formulated and implemented. In addition, as the generation mixes of many countries are being guided by a few new fossil fuel discoveries, the future availability of these fuels globally, geo-political tensions, increasing environmental pressures, and the availability of new technologies²⁵² would all be important considerations.²⁵³ Where feasible, regional power

²⁵¹ The inference drawn is similar to that of Shirley (1999) who analysed the political economy of state enterprise reform and concluded that because privatisation has similar political costs as corporatisation (instituted in the first round of reforms from the 1960s to the 1980s), the two (privatisation and corporatisation) tend to succeed or fail together. She argued that where reform was politically feasible, desirable and credible, countries corporatised and privatised successfully, whereas where countries were not politically ready to reform, substitute ownership strategies were not successful in improving performance. Shirley's comprehensive view of reforms is relevant here since earnest reforms are likely to reduce subsidies to customers, affect changes in management, and allow independent tariff reviews and adjustments, regardless of the impact on government ownership (1999:128-129).

²⁵² A range of technology options allows for improved flexibility and each option comes with its own advantages and disadvantages. A combined cycle gas plant, for example, is more energy efficient than contemporary generation technologies, has a lower unit capital cost, can be operated in either base-load

pools, alternative energies and a host of other IRP options should continue to be promoted since they give flexibility to the planning process and allow for more options to deal with the problem of insufficient generation capacity.

7.5 Contribution and Limitations of this Thesis

This thesis makes a contribution by recognising the hybrid power market as a new model in itself, and not simply a transition *to* the end state envisaged in the standard reform model. By investigating SOEs and IPPs, the thesis has revealed critical elements essential to a successful symbiosis of state-owned and privately owned generators to facilitate the attraction of new investment in generation and assist in alleviating the problem of insufficient generation capacity. By identifying disconnects in the nexus between planning and implementation of generation power projects, the thesis elucidates the factors that contribute to delays and failures of electricity generation plants and how governments and power utilities can better respond to the challenges faced. The literature, which draws on various areas of power sector and SOE reform, project management, planning, procurement and contracting, synthesises these areas to provide a framework for African power sector development. Lastly, the thesis recognises the need for new planning, procurement and contracting frameworks and highlights critical areas where improvements could be made to facilitate timely investment and commissioning of generation.

Like all case study research projects, this thesis is subject to a number of limitations. Although the research design had the benefit of increasing the explanatory power from the analytical generalisations of the empirical cases, it did entail a trade-off between the depth of the information required by each of the cases and the number of cases chosen for investigation. Although much of the information required for this thesis has been disclosed to the author, the proprietorship on some of the information on generation projects has meant

or peaking modes, and is generally easier to site than coal and hydro plants. Coal is generally a lower priced fuel but its use triggers concerns about air and water quality when expensive treatments are not factored in to meet increasingly stringent emissions standards. Wind and solar have virtually no fuel costs but, apart from the relatively high capital costs, can be unsightly or impact negatively on animal life in ecologically sensitive areas. While nuclear plants do not emit greenhouse gases, there are unresolved questions around high capital costs and the long-term disposal of high-level waste.

²⁵³ Ghana, Morocco and Tunisia have indicated strategic intents to develop nuclear power for commercial power production over the next two decades.

that it has not been in the public domain.²⁵⁴ The availability of this information, especially which related to projects that were not developed fully or were cancelled, would have allowed a deeper analysis of the problems related to planning and contracting of generation capacity. Given the limitation experienced here, it may be beneficial if, in future, an analysis of such projects could be undertaken to further elucidate the issues relating to generation capacity shortages.

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²⁵⁴ Much of the information in IPP transactions such as the PPA, EPC, O&M and other agreements between stakeholders in the power sector are confidential documents and as a result have not been available to the author.

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