Risk Management of Investments in the Electricity Sector

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Submitted to the
Institute of Graduate Studies and Research
in partial fulfillment of the requirements for the Degree of

Doctor of Philosophy
in
Economics

Eastern Mediterranean University
May 2015
Gazimağusa, North Cyprus

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ABSTRACT

Despite the major efforts by local governments and international organizations over the past two decades, most countries in Sub-Saharan Africa are still suffering from poor access to electricity. This thesis explores the investment environment in these countries with particular attention to independent power producers (IPPs). Private participation has been prescribed for decades as the solution for improving the situation; the results however are not satisfactory.

Evidence presented in this thesis suggests that in such circumstances, the independent power producers (IPPs) have an incentive to overstate the investment cost as an instrument to mitigate the country risk. This technique is an effective risk mitigation strategy under the conventional financing and contractual arrangements in such markets. It, however, promotes the use of less efficient power plants. The distortion in the choice of technology results in economic losses over the life of the plants.

Furthermore, this thesis provides an empirical framework for deterministic and probabilistic cost-benefit analysis (CBA) of investment in fuel-flexibility in the thermal generation of electricity. Natural gas has become the fuel of choice for new thermal electricity generation plants across the globe. While many countries have access to imported or domestic sources of natural gas, instabilities in the price, availability and quality of natural gas have resulted in suboptimal operation of many thermal power plants. This has created an increased interest in investments in fuel-flexible power plants. When needed, such plants can operate on alternative fuels such as the abundantly available, but more expensive, light crude oil. Countries can also benefit from such operational flexibility when faced with volatile fuel prices, or when there is a prospect of cheap domestic supply of natural gas in the future. While many countries can greatly benefit from fuel-flexibility of their thermal power plants, the political and the regulatory environment in these countries provide a disincentive for public utilities and IPPs to invest in this feature.

The findings of this research have important policy implications that can assist regulatory bodies, governments, and international financing agencies to adopt a more informed approach to the integration of private investment into the electricity generation capacity of developing countries.

Keywords: IPP, Electricity, Africa, Risk, PPA

ÖZ

Geçtiğimiz yirmi yılda yerel yönetimler ve uluslararası kuruluşlar tarafından gösterilen büyük çabalara rağmen, Sahra-altı Afrika'da birçok ülke hala daha kötü elektrik erişiminden zarar görmektedir. Bu tez, bu ülkelerdeki yatırım ortamını bağımsız enerji üreticiler (IPP'ler) odaklı bir şekilde incelemektedir. Özel sektör katılımı yıllardır bu durumun iyileştirilmesi için çözüm olarak reçete edilmiştir; ancak sonuçlar tatmin edici değildir.

Bu tezde sunulan kanıtlar göstermektedir ki bu gibi durumlarda IPP'ler ülke riskini azaltmak için yatırım maliyetini şişirme eğilimindedirler. Bu teknik, benzeri piyasalardaki geleneksel finansman ve sözleşme düzenlemeleri çerçevesinde etkin bir risk azaltma stratejisidir. Fakat bu yöntem, daha düşük verimli elektrik santrallerinin kullanımını teşvik etmektedir. Dolayısıyla, teknoloji seçimindeki bu çarpıtma santrallerin yaşam süresinde ekonomik kayıplara yol açmaktadır.

Ayrıca, bu tez termik elektrik üretimindeki yakıt esnekliğine yapılan yatırımların deterministik ve olasılıksal maliyet-fayda analizi (CBA) için ampirik bir çerçeve sunmaktadır. Doğalgaz dünya genelinde yeni termik elektrik santralleri için tercih edilen yakıt haline gelmiştir. Birçok ülke, ithal veya yerli doğal gaz kaynaklarına ulaşabilirken, fiyat, kullanılabilirlik ve kalitedeki istikrarsızlıklar birçok termik enerji santralının yetersiz işlemesine sebep olmuştur. Bu durum yakıt-esnek enerji santrallerine yapılan yatırımlara ilgiyi artırmıştır. Bu gibi santraller gerektiği zaman hafif ham petrol gibi bol miktarda bulunan fakat daha pahalı alternatif yakıt türleriyle de çalışabilmektedirler. Ülkeler ayrıca değişken petrol fiyatlarıyla karşı karşıya

kaldıkları zaman ya da gelecekte ucuz yurt içi doğal gaz kaynaklarına ulaşma ihtimali olduğu zaman, işlevsel esneklikten faydalanabilmektedirler. Birçok ülke büyük ölçüde kendi termik enerji santrallerinin yakıt esnekliğinden yararlanırken, bu ülkelerdeki siyasi ve düzenleyici çevreler, kamu hizmet kuruluşları ve IPP'lerin bu özelliğe yatırım yapmalarını caydırıcı faktör olmaktadır.

Bu araştırmanın bulguları, gelişmekte olan ülkelerin elektrik üretim kapasitesinin içine özel yatırım entegrasyonu için düzenleyici organların, hükümetlerin ve uluslararası finansman kuruluşlarının daha bilgili bir yaklaşım benimsemelerine yardımcı olabilecek önemli politika çıkarımlarına sahiptir.

Anahtar Kelimeler: IPP, Elektrik, Afrika, Risk, PPA

Dedicated to family.

ACKNOWLEDGMENT

The progress made in my research owes much to the valuable guidance and care by my supervisor, Prof. Dr. Glenn P. Jenkins, and the support and excellent lecturing skills of Prof. Dr. Mehmet Balcılar (my co-supervisor) and Assoc. Prof. Dr. Sevin Uğural. I would also like to express my gratitude to Frank Milne, Morten Nielsen, Mark Jamison, Michael Klein, Jonathan Amoako-Baah, Richard Oppong-Mensah, Sener Salcı, Alexander Chernoff, Daniel Camós, Kemal Bağzibağlı, and Yasaman Hosseinkashi for their comments and feedback.

I would also like to thank the faculty members and the staff at the Departments of Economics of Eastern Mediterranean University, Northern Cyprus, and Queen's University, Ontario, Canada, for their support; my colleagues at Cambridge Resources International for their patience; Zuzanna Kurzawa for her cheerfulness and help, and Kemal Bağzibağlı, Natiga Almazova, and Ehsan Ghazvinian for their support and companionship.

My parents' support and inspiration made every dream an option in my life, I will forever be grateful. The completion of this dissertation was made possible through extensive care and support from my wife, Shohreh; words cannot express my appreciation.

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LIST OF SYMBOLS/ABBREVIATIONS

AEO	Annual Energy Outlook (Published by EIA)
CCGT	Combined Cycle Gas Turbine
CDF	Cumulative Distribution Function
CT	Combustion Turbine
EIA	Energy Information Administration (United States)
EPC	Engineering Procurement and Construction
FDI	Foreign Direct Investment
GE	General Electric
GT	Gas Turbine
IEA	International Energy Agency
IPP	Independent Power Producer
kW	Kilowatt
kWh	Kilowatt Hour
LCO	Light Crude Oil
MHI	Mitsubishi Heavy Industries
MIGA	Multilateral Investment Guarantee Agency
MW	Megawatt
MWh	Megawatt Hour
OCGT	Open Cycle Gas Turbine
PPA	Power Purchase Agreement
S&P	Standard and Poor's
USAID	United States Agency for International Development
USD	United States Dollar

VRA	Volta River Authority (Ghana)
WB	The World Bank

Chapter 1

INTRODUCTION

This thesis explores the impact of private participation on investment decisions made in the electricity sector of developing and high-risk countries, particularly in Sub-Saharan Africa. It highlights a number of issues that can result in sustained inefficiencies and therefore great economic losses for these countries.

Energy is an important input for social and economic development. Electricity is therefore viewed as a merit good and many governments are aiming for its universal access. Due to high investment outlays required for efficient generation, transmission, and distribution of electrical power, with no government regulation, this industry would behave as a monopolistic supplier. To prevent from excessive monopoly profits, public investment, ownership, and management has operated this market for many years in almost every country.

As for many other publicly owned and operated enterprises, it did not take long for state owned power companies to show signs of inefficiency in form of high costs and poor provision of services. Private participation in the provision of public services has improved the operational efficiency and planning in many sectors, market reform was therefore tried as an attempt to improve the performance of the electricity sector. After a number of successful reforms in developed and developing countries, many governments were motivated to reform their electricity markets and allow for private participation.

Typical components of market reform include unbundling the sector to financially independent layers (generation, transmission, and retail), creating institutional capacity for regulating the relationship among different players, allowing for the participation of private sector, and improving pricing policies.

Although all reforms are pursued for the same objective, the implementation path of the reform and the final market shape is quite different from one country to another. Even in a single country, United States for instance, different market models may coexist in different regions, provinces, or states. In some markets competition is introduced at the investment level through independent power producers (IPPs) or management contracts, some others succeeded to create a wholesale market for electricity, and in a limited number of cases, policy makers have driven the market towards competition at the retail level. The final market shape depends on many factors including the market size, available natural resources, legal and political environment, income level, and access to external markets.

The reforms in most of the developing countries targeted a model where the competition was introduced only in generation. This model could be in form of a single buyer who would handle the distribution and retail, or alternatively the option for generating companies to enter into direct contracts with multiple retailers (Bacon & Besant-Jones, 2001).

Electricity tariff is used as an indicator for comparing the efficiency of the electricity market across countries and market models. However, subsidized electricity tariffs in many developing countries are hardly cost-reflective. Therefore, other indicators including the access to electricity (percentage of population provided with connection to the grid) and service quality (reliability of supply) are used as measures of performance in this sector. While high costs, and therefore high tariffs, motivated the reforms in developed countries, lack of reliability and adequate access to electricity have stimulated the reforms in most developing countries, particularly in Sub-Saharan Africa.

The governments of African countries also pursued market reforms. However, these reforms were mostly prescribed by international donors and credit agencies that stopped sponsoring public investment in the generation of electricity during the 1990s. Despite some success, most reforms in Sub-Saharan Africa had limited or no impact on the market performance and efficiency. Although most countries in Sub-Saharan Africa experienced periods of rapid growth in the 1990s, access to reliable and affordable electricity remains a challenge towards their social and economic development.

There is no sign of improvement in Sub-Saharan Africa despite the major efforts to introduce private participation (Eberhard & Shkaratan, 2012). Most of the studies that look at the underlying issues in Sub-Saharan Africa take a qualitative approach, discussing the investment climate, reform pace and it agenda, contracting issues on a case-by-case basis, or the legal and political conditions. There have been a small number of private investments in this region, outside South Africa, and therefore conducting empirical research on private participation in this region is challenging.

Market reforms have been pursued in these countries with the main objective of attracting private investment to a high-risk and volatile market. Therefore, the shape of the market and the regulatory environment are quite different in Sub-Saharan Africa. Most of these countries started the process with some form of vertical disintegration by unbundling the generation, transmission, and distribution layers. Private participation typically starts in generation where independent power producers (IPPs) would generate and sell their electricity to the public utility. Operation of IPPs is regulated and governed by power purchase agreement (PPA). These contracts play the role of the regulator in this environment, often referred to by "regulation by contract".

In a 1995 paper (Hoskote, 1995), a number of factors are highlighted for the success of IPP projects when they are regulated by contracts (PPAs) in developing countries. These factors focus on risk mitigation, where it is suggested that the investors choose smaller projects (less than 200MW) to speed up the financing closure, ensure political commitment to reduce country risks, include take-or-pay provisions for the output to transfer the demand risk away from the IPP, and use as much local capital as possible to reduce the foreign exchange risk.

Such provisions are quite normal in PPAs that are signed in Sub-Saharan Africa today, transferring most of the project risk to the public utility and consumers. These contracts often include provisions that pass the fuel cost to the public utility. It is quite rare to see the fuel pass-through and the take-or-pay provisions coexist in more developed electricity markets.

The special treatment of risk in these contracts creates a unique regulatory environment, which can make it difficult to benefit from competition through private participation. Despite these differences and questionable outcomes of previous attempts towards private participation, market reform and private participation are still being advised by international donors and credit agencies.

This thesis highlights two issues that are rooted in the way country risk and fuel risk are treated. These issues can significantly affect investment decisions made in such environments and result in economic losses. Therefore, it is important for policy makers and the public agencies involved in the design and implementation of market reforms and system planning, and conducting negotiations on contracts to consider them.

Discussion presented here draws from various fields of research. Chapter 2 provides an overview of the literature that discuss the general challenges around private participation in the provision of public services, market shapes and policies in Sub-Saharan Africa, and the experience of the private participants in this region.

Chapter 3 presents an economic framework for evaluating the investment decisions in the power generation sector, highlighting the importance of analyzing every project as a part of the systems of electricity generation.

Since the allocation of risk is a major component in the discussions presented here, chapter 4 explores the sources, impacts, and mitigation techniques of risks around the operation of IPPs. This thesis is then followed by two chapters that look into the particular issues of overstating the investment cost as a risk mitigation technique (chapter 5), and the value of fuel-flexibility in Sub-Saharan Africa (chapter 6). Chapter 5 explores and empirically shows that the IPPs have a tendency to overstate the investment cost in order to mitigate country risk. The discussion in this chapter is supported with a mathematical model and statistical evidence.

Chapter 6 highlights the value of fuel-flexibility in power generation when the countries are faced with unreliable supply of fossil fuel or prospect of domestic production. The study presents a number of evaluation frameworks and provides a numerical example for estimating the economic savings from fuel-flexibility when the supply of natural gas is subject to interruptions.

These discussions and analyses are conducted within the investment environment of Sub-Saharan Africa. The main conclusions of this thesis and its policy recommendation are presented in chapter 7.

Chapter 2

SURVEY OF LITERATURE ON THE PRIVATE INVESTMENT IN EMERGING ELECTRICITY MARKETS

2.1 Access to energy and economic development

Numerous studies have attempted to examine the relationship between economic growth and consumption of electricity, their results are however inconclusive (Stern & Enflo, 2013). The literature on this relationship in Sub-Saharan Africa follows a different path. Recent studies show that unreliable and inadequate supply of electricity is a major barrier to social and economic development in this region (Andersen & Dalgaard, 2013; Eberhard & Shkaratan, 2012; Elumelu, 2013; Nadia, 2012).

2.2 Private participation and market reform

Private participation in the provision of public services has been pursued in the electricity sector for more than three decades. This process started with the successful reforms in industrialized countries and was shortly followed by the emerging markets. While the motivation in the industrialized countries was largely to reduce the electricity prices, it was mostly deemed in the emerging markets as an instrument to increase access and improve reliability (Deloitte Touche Tohmatsu Emerging Markets, 2004). The reforms in emerging markets started in the 1990s as international development and financing agencies shifted away from supporting investments in state-owned infrastructure and prescribed reforms that would allow for the participation of private sector (Manibog, Dominguez, & Wegner, 2003).

The urge for improved energy access in the emerging markets led to market reforms in almost every developing country (Bacon & Besant-Jones, 2001). As a result, there was an increased level of private investment during the 90s. After the 1997 Asian financial crisis, however, emerging markets experienced a sudden drop in the private investment, particularly in foreign direct investments (FDIs). Together with a number of unfavorable cases where privatization resulted in questionable outcomes, these factors raised many questions about the effectiveness of reforms and privatization in emerging markets. While some studies (Eberhard & Gratwick, 2011b; Kessides, 2012; Malgas, Gratwick, & Eberhard, 2007) report on the economic gains achieved from these reforms in the developing markets, most of the literature is concerned with the questionable outcomes.

Some studies highlight the gaps in the provision of services and expected impacts, evidence such as growth rates in the investments that are far below the required levels (Bazilian et al., 2012), or the inadequacy and unreliability of international capital markets (Deloitte Touche Tohmatsu Emerging Markets, 2004). A large number of studies have empirically tested the results of the reforms in emerging markets; some of them are summarized in Table 1.

Table 1: Conclusions from some of the recent studies on the outcome of market reforms in emerging markets

Study	Panel data	Conclusions
(Nepal & Jamasb, 2012)	27 transition economies (1990-2008)	"…the success of power sector reforms in developing countries largely depends on the extent to which they synchronize inter-sector reforms in the economy."
(Erdogdu, 2011)	63 developing and developed economies (1982-2009)	The experience in developed countries cannot be prescribed to emerging markets.
(Nagayama, 2009)	78 countries (1985-2003)	"…the development of liberalization models in the power sector does not necessarily reduce electricity prices."
(Zhang, Parker, & Kirkpatrick, 2008)	36 developing and transitional countries (1985 - 2003)	Find privatization and regulation ineffective on their own, but competition to have significant impact.
(Nagayama, 2007)	83 countries (1985 - 2002)	"Privatization and the introduction of foreign IPP and retail competition lower electricity prices in some regions, but not all."

2.3 Explaining the outcomes from privatization and market reform

A number of reasons are discussed in the literature explaining the unexpected outcomes of market reforms in developing countries. Many studies have emphasized the failure of policy makers to adjust the reform doctrine to the specific conditions of the emerging markets. The performance issues of energy markets observed in many developing countries are rooted in limited coverage, poor governance, and weak public institutions. The privatization, however, was pursued as the main objective of the reform and, in many cases; it is not be the right cure for such problems (Estache, Gomez-Lobo, & Leipziger, 2001; Wamukonya, 2003).

Other studies have highlighted the challenges in creating a competitive environment through privatization, including the inability of low-income countries to attract enough investors for a truly competitive bidding process (Phadke, 2009), or the unfavorable investment climate in the country as a whole (Eberhard & Gratwick, 2011b). Market related issues such as the clarity of the regulatory framework, and the access to reliable and competitively priced sources of fuel are also among the factors discussed in literature (Eberhard & Gratwick, 2011b; Malgas et al., 2007).

A joint study by the World Bank and USAID (Deloitte Touche Tohmatsu Emerging Markets, 2004) summarized the lessons learned from the reforms in four fundamental insights: 1) The need for a better understanding of the risk, the business cycle, and the decision-making process of capital markets; 2) The reliance on international capital markets results in an increased volatility; 3) Development of power sector requires coordinated progress on political, macro-economic, sector, and financial aspects in parallel; and 4) Reforms will be more enhanced through a more cross-sectorial development strategy.

While most of the attention in literature is around market risks, investment environment, and market reform, a limited number of studies (Woodhouse, 2005a; Woodhouse, 2005b) have highlighted the issues resulting from high levels of political risk. With private sector entering a reforming market as a greenfield independent power producer (IPP), or takes over a public utility in a divestiture, it becomes exposed to "obsolescing bargain" risk. Furthermore, such privatization schemes often take place as a part of a greater reform in which subsidies may be removed and nonpaying customers are no longer served, such timing issues would also create a greater risk for the private investor.

2.4 Regulatory framework and the investment decisions

Since this dissertation is mostly focused on the investment decisions made by the private sector in Sub-Saharan Africa, it is also important to acknowledge the large body of research that focuses on the impact of regulatory frameworks on the investment decisions made by the private sector. A recent study provides a summary of conclusions and discussion raised by this literature (Camacho & Menezes, 2013). The results of these studies are however only applicable where some standard regulatory framework (price-cap, cost-of-service, etc.) is practiced.

To attract private investors to high-risk markets, the public utility off-takes the output, passes the fuel through, and even indexes the payments in a foreign currency. These provisions are provided to an independent power producer (IPP) under a long-term power purchase agreement (PPA) (Gratwick & Eberhard, 2008; Hoskote, 1995). Such PPAs do not resemble any of the common regulatory frameworks observed in more developed, or less risky, markets.

Chapter 3

CHOICE OF TECHNOLOGY FOR POWER PLANTS

3.1 Introduction

The market for electrical power is unique in a number of ways. The technologies for generation, transmission, and distribution in this market are complicated from both a technical and an economic perspective. Since the storage of electrical energy is expensive, generation and consumption must almost match at all times. Therefore, the system must work in an integrated manner to serve the fluctuating demand where some of the generation capacity would remain idle in some periods (low demand). Finding the most economically efficient way to stack and operate power plants is therefore an intricate process.

Generation technologies come with varying cost structures, operational flexibility, environmental impacts, and unit sizes. A qualitative comparison of some of these technologies is presented in Table 2. The unit size, column 2, shows the minimum construction size of these power plants in relative terms. Plants that can be constructed in smaller sizes have advantages such as faster construction and limited financing requirements, however, such technologies are often inefficient or very expensive. The lead-time, column 3, is an indicator of how flexible the technology can be operated. Shorter lead-time increases the ability of the system operators to bring these plants online and take them offline in response to demand peaks.

There is a significant negative correlation between the capital cost and fuel cost (columns 4 and 6). This relationship is the main reason one can find a collection of these technologies in almost every system of electricity generation. The more efficient, but expensive, technologies are suitable for generation around the clock to serve the stable demand (base–load). Cheaper technologies that require a smaller investment cost are inefficient in the use of fuel; however, the cost of inefficiency is in the use of the technology, therefore, such technologies are suitable options for serving the demand peaks that happen for limited number of hours in any given day.

A combination of base–load, peaking, and medium–load technologies is usually stacked together to serve the varying demand for electricity in an economically efficient way. A simple numerical model for optimal stacking of technologies is presented in the following section.

Table 2: Qualitative comparison of generation technologies (IEA-OECD, 2003)

Technology (1)	Unit Size (2)	Lead-Time (3)	Capital Cost (4)	Operating Cost (5)	Fuel Cost (6)	Co2 Emissions (7)
Thermal (Gas)	Medium	Short	Low	Low	High	Medium
Thermal (Coal)	Large	Long	High	Medium	Medium	High
Nuclear	Very large	Long	High	Medium	Low	Nil
Hydro	Very large	Long	Very high	Very low	Nil	Nil
Wind	Small	Short	High	Very low	Nil	Nil
Recip. Engine	Small	Very short	Low	Low	High	Medium
Fuel Cell	Small	Very short	Very high	Medium	High	Medium
Photovoltaic	Very small	Very short	Very high	Very low	Nil	Nil

The demand for electricity changes from one hour to the next. As the demand and supply of electricity must match at all times, demand schedule is an important input for optimization of the generation fleet. Figure 1 presents a hypothetical daily load curve where the vertical axis presents the amount of energy demanded in every hour, and the horizontal axis shows the time of the day. The daily load curve can have a different schedule on weekends and holidays, and varies significantly by the season in countries that experience significant temperature shifts from one season to another.

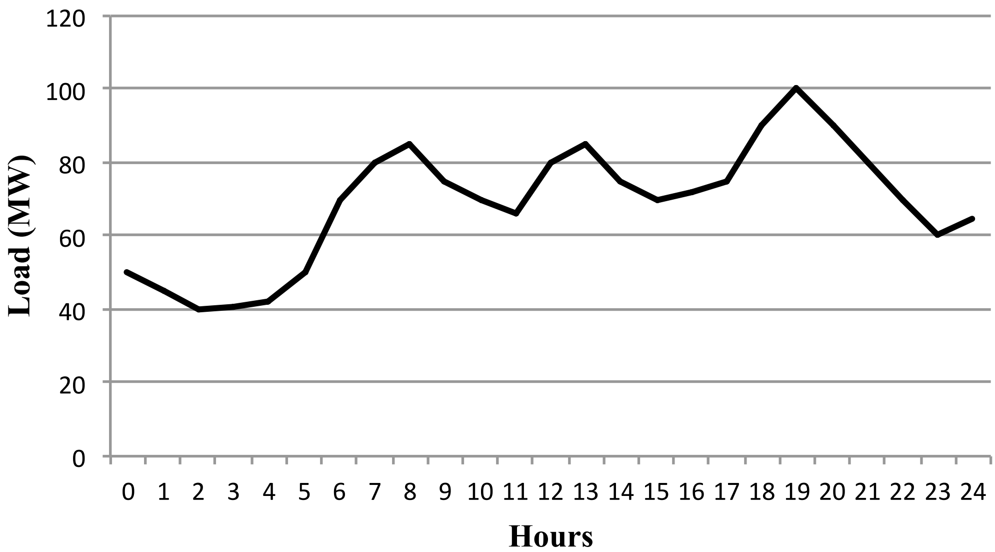

Figure 1: Daily load curve

Load curves can be constructed for any length of time (weekly, monthly, seasonal, and yearly) by horizontal extension of the daily load curves. These curves inform the planners about the length of the time electricity is demanded at different levels, maximum generation capacity required, frequency of demand fluctuations, and timing of peaks. As we see later in this chapter, this information is quite important in planning an economically efficient system.

3.2 Economic efficiency: the role of system planning and dispatch

3.2.1 The value of output

The technology of a power plant is decided at the investment stage. The equipment used in a power plant can have a useful life anywhere from 20 years to 50 or more. Therefore, it is critical to carefully evaluate the choice of technology before committing to such investments. In cost-benefit analysis of investment in power generation, costs are well known for most technologies with a good level of certainty. However, it is often a challenge to find a suitable measure of benefits.

As discussed by (Jenkins, Kuo, & Harberger, 2011), the correct way to find a measure for the benefits of the plant's output is to find the "least alternative cost". During its life, the power plant is operated within a system, which experiences change at both the demand side and the supply side. The operation of the plant is therefore taking place in form of a "motion picture". To correctly measure the "least alternative cost" of generation, as the measure of benefit for each period, one needs to carefully observe the plant's role in the system over its life.

This process can be performed through static or dynamic numerical models or computerized simulations. The simpler models could come up with an estimate of a "standard alternative cost", while the more sophisticated approaches could find the most optimized path for the system's expansion and estimate the "minimum alternative cost" (Jenkins et al., 2011). Simple static models start with information on the investment, operating, and fuel costs, and try to minimize the cost of servicing the demand schedule.

As models become more sophisticated they will also account for additional parameters such as the lead-time of different plants in the system, transmission and distribution constraints, storage capacity, uncertainties in supply and demand, and cycling costs. The objective of this chapter is to provide an introduction to the process of selecting a technology for the expansion or the partial replacement of generation capacity. This objective is satisfied using a hypothetical example within a simplified model. Studies that look at system optimization under alternative policies, market models, regulatory regimes, or technical configurations, often rely on more sophisticated models.

3.2.2 Optimal stacking of homogenous thermal plants

To illustrate the stacking process, a simple numerical and graphical example is presented here based on three homogeneous thermal technologies to choose from. The cost structure of these technologies is presented in Table 3. For each technology, column 2 represented the yearly rental cost, which is estimated based on the investment cost, cost of capital, and the depreciation rate. Column 3 shows the fuel cost, which is assumed to be the only operating cost for simplifying the model. Single-Cycle Gas Turbine (SCGT) is the least efficient technology, however, it is also the least expensive of the three at the investment stage. Coal on the other hand, is quite capital intensive but its fuel cost is the lowest. Combined-Cycle Gas Turbine (CCGT) is in between the other two in terms of both investment and fuel costs.

Table 3: Homogeneous thermal technologies used in the optimal stacking example

Technology (1)	Yearly Rental Cost - $/kW (2)	Fuel Cost - $/kWh (3)
SCGT	$90	$0.21
CCGT	$225	$0.11
Coal	$525	$0.06

While one can qualitatively suggest that coal, CCGT, and SCGT are good options for base-load, medium-load, and peak generation, the objective here is to find the exact line in between these technologies in terms of installed capacity to serve the demand at minimum cost. The first step is to find the minimum expected number of firing hours for a plant to be operating before investment in a more efficient technology is justified.

The number of hours a thermal power plant is fired in a year is known as its Capacity Factor. The total cost of generation per kW of capacity can be calculated as a function of the capacity factor. This relationship is shown in Equation 1, where c_i is the cost per kW for technology i, K_i is its yearly rental cost, h is the capacity factor, and F_i is its fuel cost.

$$c_i = K_i + hF_i \qquad \text{Equation 1}$$

The line can be drawn in between every two technology by finding the capacity factor that would equate the yearly costs. For instance, Equation 2 estimates the capacity factor that would justify the investment in CCGT over SCGT. Meaning that for any capacity factor over 1,350 hours (as shown in Equation 2), CCGT would be the correct choice.

$$K_{SCGT} + hF_{SCGT} = K_{CCGT} + hF_{CCGT}$$

$$h = \frac{K_{CCGT} - K_{SCGT}}{F_{SCGT} - F_{CCGT}} = 1{,}350 \qquad \text{Equation 2}$$

In the same fashion, for any capacity factor above 6,000, hours coal is the correct choice over CCGT. This concept is best illustrated using the screening curves as shown in Figure 2. The slope of these curves depends on the cost structure, higher fuel costs results in a steeper slope as the number of firing hours increase. The borderline of switching to another alternative is found where these curves intersect (1,350 for SCGT and CCGT, and 6,000 for CCGT and coal).

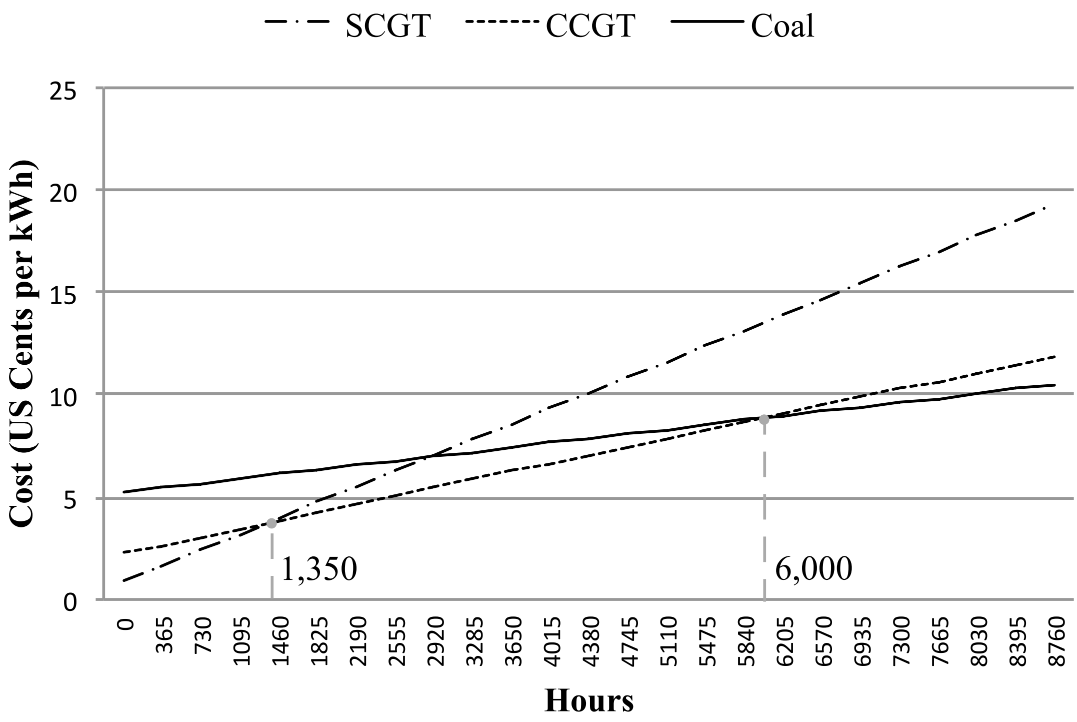

Figure 2: Standard screening curve

Screening curves were first introduced in 1969 and there have been advancements in the structure and use of them since then (Batlle & Rodilla, 2013; Phillips, Jenkin, Pritchard, & Rybicki, 1969). The estimated borderline capacity factors can help in choosing the right mix of power plants based on these technologies. Please note that there are 8,760 hours in a year. If the intersection takes place outside the possible range of capacity factors (below 0 and above 8,760 hours), then one of the technologies is too expensive at all capacity factors and must be dropped from the menu.

To complete the picture, one needs to incorporate the demand schedule. The capacity factor for each megawatt of generation capacity can be found using the load curves. To simplify this process using a graphical presentation, a cumulative distribution function (CDF) of the annual load curve is constructed. This curve is called the "annual load duration curve", and is shown in Figure 3.

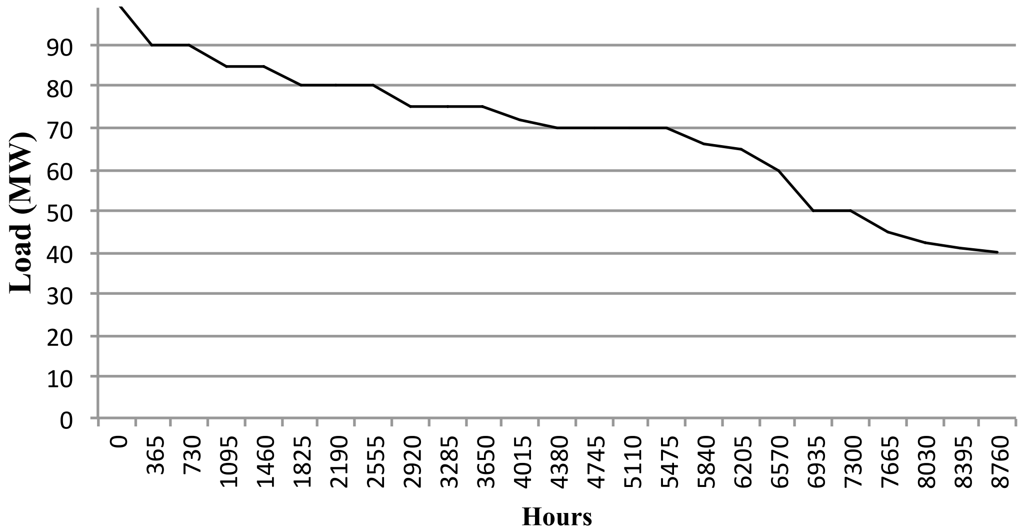

Figure 3: Annual load duration curve

The optimal stacking can now be graphically illustrated by equating the annual load duration curve with the borderline capacity factors (Figure 4).

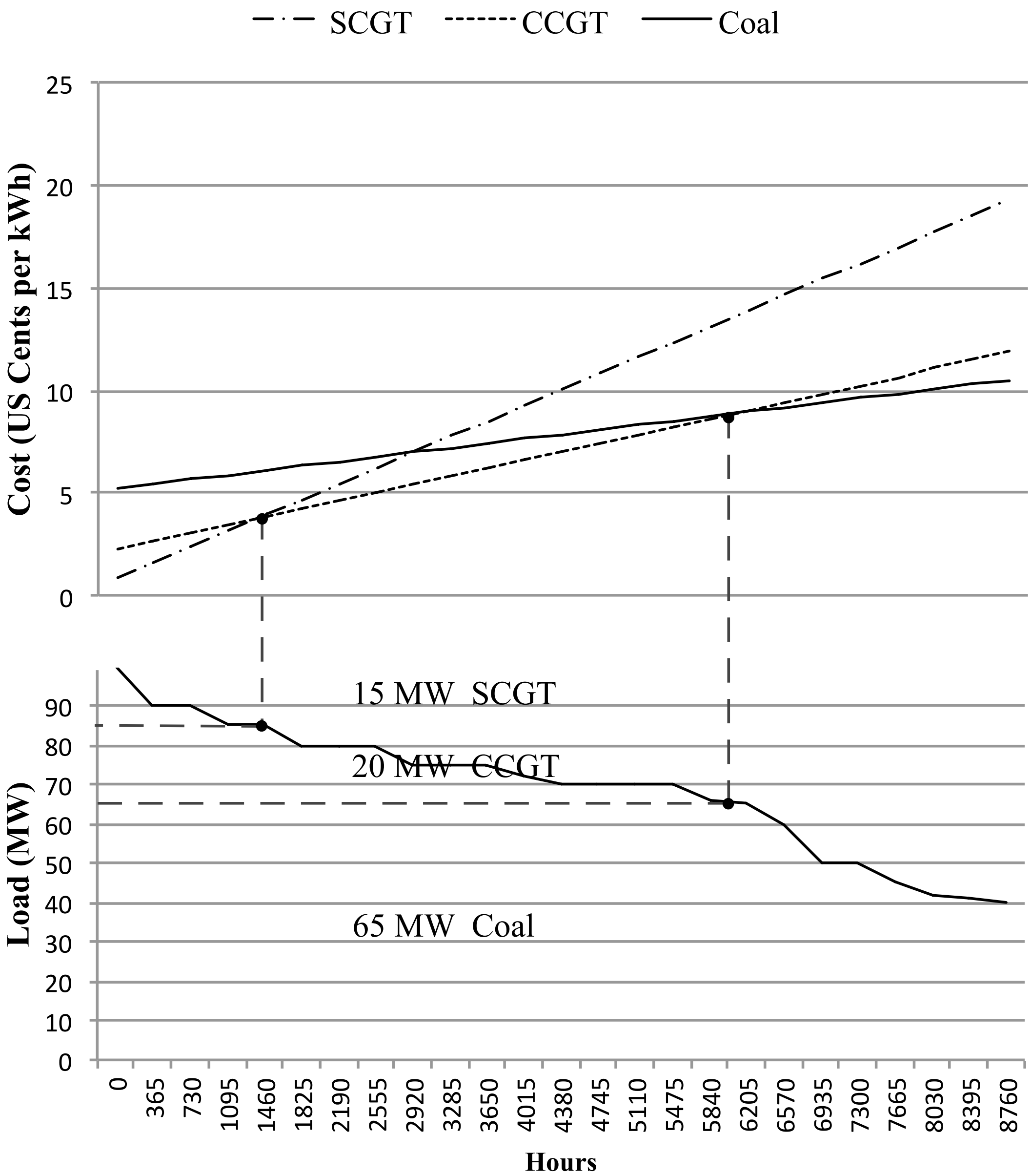

Figure 4: Optimal stacking of homogenous thermal plants

As illustrated by this diagram, the optimal system would include about 65 MW of coal, 20 MW of CCGT, and 15 MW of OCGT. The peaking plant, SCGT, will be fired for 1,350 hours, the medium-load plant, CCGT, will be fired for 6,000 hours, and the base-load plant, coal, will be fired at all times (there is a total of 8,760 hours in a year). One can numerically calculate the total cost of the system based on these values and see that this stacking order results in the least total cost.

For ease of calculations, many factors were not included in this example, however it facilitates one's understanding of how a thermal benchmark for the "standard alternative cost" can be constructed for a power plant. From this example, one learns that the "standard alternative costs" of any power plant during the peak hours (total of 1,350), medium-load hours (total of 4,650[1]), and base-load hours (total 2,760[2]) are equal to the marginal firing cost of a SCGT, CCGT, and coal plants respectively.

These values are highly sensitive to the parameters used in the optimal stacking process, including the cost of capital, investment cost of each technology, fuel prices, and changes in the demand schedule. Later in this chapter, and in the following chapters, we will see how distortions and uncertainties around these parameters and other factors can affect the decisions made by the planners and investors in emerging markets, particularly in Sub-Saharan Africa.

3.2.3 Moving beyond homogeneous thermal

The example presented above relies on a number of strong assumptions and one may find its capacity inadequate for evaluation of investment decisions in technologies other than homogeneous thermal. The use of this model, however, extends over large hydro and storage systems, while the evaluation of the intermittent renewable sources such as wind and solar introduces new difficulties and requires the use of more advanced models.

Large hydro plants have no fuel costs and marginal operating costs. Therefore, they are a good option for base-load generation. There are however, a number of issues to consider in integrating large hydro to the analysis. First, the capacity of large hydro

[1] 1,350 deducted from 6,000
[2] 6,000 deducted from 8,760

is constraint to the geological characteristics of the country. This needs to be added as a constraint. Second, hydro dams come with two sources of major uncertainty; one is around the investment cost and time (Ansar, Flyvbjerg, Budzier, & Lunn, 2014), and the other one is the climate change. On the latter, many countries in Sub-Saharan Africa are currently relying on thermal peaking technologies for base-load generation simply because the droughts have drastically reduced their hydro generation capacity. Incorporating these factors requires the use of probabilistic analysis in the model and carefully testing the sensitivity of the results to such uncertainties.

Storage systems would traditionally be in form of mechanical reserves such as pumped hydro reservoirs and flywheels. More recently, new technologies such as power-to-gas, electrochemical batteries, and thermal storage have been utilized or tested in grid-scale applications. Storage of electricity is only valuable in changing the time of its usage. For instance, pump storage is used to store the energy produced by a nuclear plant during the base-load hours so that it can be used during the peak, when the "least alternative cost" is much higher. Another example is the thermal storage of concentrating solar panels that can absorb the heat during the day (presumably base-load period) for later electricity production in evening (presumably peak period).

Storage systems, however, come at two costs: first, the investment and maintenance cost of the storage facility itself; and second, the energy losses in the storage and regeneration process. The expected benefits from consumption of the electricity at a different time (the gap between the base-load value and peak value) must satisfy these costs before investment in storage systems can be justified.

Evaluation of the investment in intermittent renewable sources such as wind and solar introduces a set of new challenges. The availability of these sources and the timing of their generation are subject to uncertainty and threaten the reliability of the system. Therefore, one needs to take into consideration issues such as the correlation between the predicted timing of supply and demand peaks, the share of intermittent sources currently in the system, the amount of dispatch-able capacity in the system that can absorb the fluctuating supply of renewables, the capacity of the transmission system for higher stress levels, certainty level of forecasts, and the ability of the market model to buy and sell intermittent energy.

Incorporating all these parameters in a static model is almost impossible. Therefore, dynamic programing models and computerized simulation software are mostly used to assess the impact of integrating intermittent renewable sources in the system. There is a vast literature on this topic utilizing various forms of dynamic models (Zipf & Most, 2013).

3.3 Other factors affecting the choice of technology in emerging markets

The investment climate in the emerging markets is affected by a number of factors that can distort the decision making process and result in suboptimal technological choices.

3.3.1 Country specific factors

3.3.1.1 Transmission and distribution network limitations

With an aging and constrained transmission and distribution networks, many emerging economies are unable to invest in large, centralized, and efficient power plants. Planners are forced to invest in smaller plants in a distributed way, resulting in an over utilization of inefficient plants such as SCGT and diesel generators.

3.3.1.2 Undervalued fuel sources

Fossil fuel is priced below its economic value in many emerging markets. This is usually experienced when a country has access to domestic reserves or when it subsidizes the import of fossil fuels. In both cases, lowered fuel prices distort the decisions made by the planners and investors in a range of sectors including electricity generation, resulting in an overall tendency towards inefficient technologies.

3.3.1.3 Excessive levels of foreign debt and capital shortage

The governments of many emerging markets are heavily indebted to foreign countries or international financing institutions. The capital deficits increase the cost of borrowing and therefore make it difficult to invest in capital-intensive technologies. With an increased cost of capital, planners and investors would opt for cheaper power plants that are usually less efficient.

Furthermore, shortage of capital may delay replacement decisions beyond what would be optimal. As such investment decisions are delayed, the system becomes inefficient in the use of fuel and is faced with increased maintenance costs.

3.3.1.4 Emphasis on fuel diversification and fuel-flexibility

Some governments put an emphasis on fuel diversification in response to a range of reasons including energy security and external pressure. In case of fuel-flexibility, the best example is the need in emerging markets to invest in technologies that can operate on a range of liquid or gas fuels. Such power plants can never achieve the efficiency ratings exhibited by power plants manufactured to operate on gas only (Kehlhofer, Rukes, Hannemann, & Stirnimann, 2009).

When policy dictates the choice of technology, in most cases, the resulting investments are not financially or economically the most efficient use of funds. These power plants will cost the economy more than the “standard alternative” due to their expensive price tags or inefficiencies in the use of fuel.

3.3.1.5 High levels of political and economic risks

High levels of economic and political risk are very common in emerging markets. While government and multi-lateral guarantees can partially transfer this risk away from the investors (Woodhouse, 2005b), the residual risk will still affect the investment decision. The direct impact on the choice of technology is through an increased risk premium on the cost of capital. There are also other measures taken by the investors in response to high levels of political risk that will be discussed in the upcoming chapters.

An increase in cost of capital or higher levels of political risk will both result in a tendency towards smaller capital investment and an increased reliance on fuel and other operating costs.

3.3.2 Project specific factors

3.3.2.1 Fuel supply constraints

In some cases, the constraint on the volume of fuel that can be delivered to a location limits the capacity of power plants. This takes away the ability to invest in larger, centralized, and efficient power plants.

3.3.2.2 Rushed investment

Many emerging markets face with periods where generation capacity needs to be expanded in an emergency. Examples include unexpected droughts, power plant failures, or a sudden increase in consumption. When investment is rushed, many efficient technologies are ruled out as an option since their construction takes a relatively longer period. Most countries only invite emergency power generation companies for a limited time until plants that are more efficient are constructed. Some others, however, do not have the immediate access to funds or the negotiation power for temporarily adding emergency units. In such cases an inefficient emergency solution might remain in the system for a much longer period.

3.3.3 Planning shortfalls

3.3.3.1 Underestimating demand growth

When demand grows uniformly, the system needs to be expanded with base-load technologies. Poor, or politically influenced, planning practices may ignore the long-term objectives of the system and promote the investment in peaking technologies to address the immediate needs with the smallest amount of financing possible. The result usually is a highly inefficient system where peaking plants are fired beyond their economically justified capacity factor.

Furthermore, when the mix of generation fleet is in a suboptimal state, which is the case in most of Sub-Saharan Africa, the choice of technology is not dependent on whether the demand is growing during the peak, intermediate, or off peak times Investments in such conditions should always be directed to address the major inefficiency condition and move the system towards an optimized state.

3.3.3.2 Failure to account for the change in fuel prices

Underestimating the change in fuel prices becomes a major problem when investment decisions are made during the periods when fuel oil prices are highly variable. Underestimating the price of oil results in increased fuel consumption, while overestimating its price can overload the generation mix with capital-intensive technologies. The economic cost in both cases will exceed the “standard alternative cost”.

3.3.3.3 Absence of peak pricing schemes

As a major issue across Sub-Saharan Africa, and many other emerging markets, electricity prices are heavily politicized and regulators do not have the strength to introduce tiered electricity tariff structures that are based on the time of use. The demand from the system during the peak hours is therefore higher than it would be in the presence of peak load pricing. Higher tariffs during the peak periods are justified because of the higher marginal costs of production during these times as compared to the marginal costs of generation at off peak periods. A peaky system promotes further investment in peaking technologies and results in an overall inefficient system.

3.3.3.4 Ignoring the low efficiency of base-load power plants

In some cases, planners fail to observe the inefficiencies in the operation of existing base-load fleet and take their current cost as the “standard alternative cost”. Such a high price for the “alternative” hardly lets the project evaluation process to produce sensible results, continuously approving investments that are suboptimal.

3.3.4 Privatization issues

Poorly designed contracts can allocate too much risk on one input and take away all the risk on another. For instance, power purchase agreements (PPAs) in many emerging markets takes all the market risks (fuel price, fuel availability, electricity price, electricity demand, etc.) away from the private party. The investors are however left on their own to find multilateral guarantees or other instruments to mitigate the political risks threatening their capital investment. This results in a distorted set of investment incentives for the private sector.

Input market distortions promote an inefficient use of resources. Although regulators try to control the private party's investment decisions, often times private investors can utilize information asymmetry to achieve their targets outside the boundaries set by the regulators.

Chapter 4

RISK AND IPPS: SOURCES, IMPACT, AND TYPICAL MITIGATION TECHNIQUES

4.1 Introduction

Independent Power Producers (IPPs) are private power generators that produce electricity for direct sales to consumers, sales to the public utility, or both. IPPs are an alternative to state-owned electricity generation plants. Many state-owned power plants have been replaced by or converted to IPPs as the private sector is expected to have access to better technical skills and operate more efficiently. Another advantage of IPPs is their access to a wider range of funding sources for the financing such projects.

Promotion of IPPs has not been limited to the developed or liberalized markets. Many less developed and reforming markets, referred to by “emerging markets” in here, have also turned to IPPs. This has largely been in response to the public utilities’ financial constraints for system expansion, promotion of private participation by international development and financing agencies, and restructuring of the power sectors to allow for such investments. Vertical disintegration of the sector to generation, transmission, and distribution, with financial independence, has been a major catalyzer for the introduction of IPPs.

A typical power plant has a span of life greater than 20 years, comes with large investment requirements, and is expected to generate a steady return to cover the initial investment and its operating costs over its life. Similar to other infrastructure projects, the majority of investment in grid-scale power plants is sunk within the first year of the project, leaving these projects exposed to a range of risks as their benefits are spread into uncertain future. Many studies have discussed the risks around the operation of IPPs in liberalized (Bolinger, Wiser, & Golove, 2006; Gaggero, 2012; IEA-OECD, 2003; Roques, 2008; Roques, Newbery, & Nuttall, 2008; Wiser, Bachrach, Bolinger, & Golove, 2004) and emerging markets (Hoskote, 1995; Woodhouse, 2005a; Woodhouse, 2005b). The experience of IPPs has been quite different in the liberalized markets as compared to the emerging ones. The divide in the literature is evidence to this and is rooted in the differences between these markets. This chapter intends to highlight how the investment risk profiles differ under each of the market conditions and why the mitigation techniques and shape of contracts in each market are significantly different.

Power Purchase Agreements (PPAs) are the most common form of contract to govern the operation of IPPs. These contracts play an important role in defining the financial and technical obligations of each party, as well as implementing risk transfer and incentive mechanisms. The electricity generated by an IPP can be sold in a spot market, through fixed contracts, or through a rental agreement (Bolinger et al., 2006). The spot market is not available in the case of the emerging electricity markets and therefore we will focus on the latter two options.

Under a fixed contract, the purchaser agrees to buy a specified amount of electricity at a fixed or indexed price. It is a very common approach for base load technologies where the off-taker has a reasonably good demand forecast and is willing to take its risk for a reduced price of electricity. The IPP, on the other hand, is made responsible for procurement of fuel, and hence bears the risks associated with it. Rental agreements[3] are mostly used for peaking plants where the buyer rents the facility and pays for its investment cost but only utilizes it on demand, bringing the fuel and taking the electricity away. This way the buyer has a reduced exposure to demand risk, however it has to procure or pay for the required fuel.

The investment environment in the emerging markets is quite different. IPPs are faced with different risk profiles and contracting options. Political risk is a major issue in these markets (Woodhouse, 2005b) and oftentimes the authorities find it difficult to attract private investment. It is quite common in such circumstances to see PPAs that contain both a take-or-pay component as well as a fuel pass-through component to make these projects more attractive for investors. Other such provisions include PPA payments in a foreign currency and multilateral guarantees. Since the prices are often politicized and rigid in the emerging markets, the overall financial stress in the sector, as a whole, is higher in these markets. A recent study (Eberhard & Gratwick, 2011a) presents a good discussion on the experience of IPPs in emerging markets of Africa.

Technical risks, market risks, regulatory risks, and political and economic risks are discussed in this chapter. Each of the following sections discusses the sources, cost bearer, and some of the common mitigation techniques of each type of risk in both the liberalized and the emerging markets.

[3] Sometimes referred to by tolling agreements.

4.2 Technical risks

Any unexpected deviation from the expected performance of the power plant is classified under the technical risk category. The two most common risks include the investment completion issues (cost and time over–runs) and efficiency drop. Such problems arise from poor planning and implementation at the construction stage, and poor maintenance of the power plant respectively. The consequences of the technical risks are delays in commencement of operation, increased costs, and reduced capacity. Since the risk needs to be transferred to the party who can manage it best, the IPP should naturally be the cost–bearer in this case.

There is no need for risk transfer provision under fixed price contracts as the IPPs bear the financial consequences of technical risk anyway. Under a rental agreement, or cost-plus regulation models, however, the cost of the technical risk is usually transferred to the IPP in the form penalties for underperformance or other incentive contract. IPPs often mitigate this risk through turnkey EPC contracts and proper maintenance. The importance, allocation, and mitigation of technical risks are very similar in all types of electricity markets, both liberalized and emerging. A study on two power plants in Tunisia showed how the underestimation of the quality of natural gas resulted in severe damages to the turbines halting the operation of one of the plants (Malgas et al., 2007).

While the expertise and the experience are important parameters in determining the competency of the IPP, the incentives put forward in the contracts will also play an important role. Inefficiencies observed in the publicly owned and operated power plants are simply resulting from incentive issues. The private sector is no better in the operation of power plants than is the public sector unless it is given the right set of incentives.

Cost over-runs and time over-runs are quite common in hydro and nuclear plants. However, thermal plants are not as exposed to such risks as they are more or less location independent and can be installed in preconfigured packages (Bacon et al., 1996).

4.3 Market risks

The market risks include any unexpected fluctuations in the quantities and the prices of an inputs or an output of the project. The financial and technical performance of IPP project can be significantly affected as a result of fluctuations in the markets for fuel and electricity. The price of fossil fuel, specially oil and gas, is subject to uncertainties in the long run while various security, political, and climate issues can threaten their availability. In addition, demand for electricity and the price paid for it by the consumers can also fluctuate.

Variations in the fuel and electricity prices can affect the financial or economic viability of the project positively or negatively. The fuel availability and electricity demand will, however, only affect the project in the negative direction since the plant’s generation capacity is limited to its original design. Looking at the project from an economic standpoint, these fluctuations can threaten the viability of the project through increased costs, underutilization, and reduced revenue.

The significance of the market risks and the allocation of their costs are different in emerging markets as compared with liberalized ones. Each of these risks is discussed in a separate subsection below.

4.3.1 Fuel price

The price of electricity is not fixed in liberalized markets and is highly correlated with the price of fossil fuel. Therefore, most of the fluctuations in fuel prices are passed to the consumers. IPPs would only bear the fuel price risk under fixed contracts that do not index the price of output to the fuel costs. In that case, IPPs would opt for a fuel diverse portfolio of power plants (Roques et al., 2008), or use the instruments available in financial markets to hedge against these fluctuations.

The politicized and rigid consumer prices for electricity create a different environment in emerging markets, where the fuel price fluctuations are typically absorbed by the procuring agent and hardly passed to the consumers directly. As the IPPs are reluctant to commit to such financial stress, the public agents have no choice but to procure the fuel or reimburse the IPP for the exact payment in a pass-through arrangement. This is similar to a rental agreement in the liberalized markets, however, as discussed later, this provision is usually coupled with a take-or-pay contract for the output in emerging markets.

To ensure that the private operator maintains the power plant to keep its expected thermal efficiency under such agreements, PPAs specify the amount of fuel required per unit of electricity delivered. This provision works like an incentive contract where the operator has to pay for any additional consumption or receives the extra fuel, or the financial value of it, if it uses less fuel than what is set in the contract. The design of these agreements is quite important as the IPP has a significant control over the efficiency of the power plant.

The cost of fossil fuel is not only variable, but its variation is difficult to predict. Since the investment made in power plants usually locks the project into one fuel, or one category of fuels, for a long span of life, it is important to have a good understanding about the trends in the fuel prices and the possible deviations from the expected values. The US Energy Information Administration (EIA) publishes forecasts for the price of fossil fuel in its Annual Energy Outlook (AEO) every year. The forecasts cover a long span of life (about 20 years) and they are constantly changing from one issue to another. The nature of supply and demand is changing as new sources and extraction technologies are discovered, political instabilities affects major producers in the Middle East and North Africa, and demanders behavior changes with new groups of consumers entering and some existing groups leaving the market.

Five of the recent forecasts for the price of natural gas in the United States, published by the EIA AEOs, are illustrated in Figure 5. This is only to show how the forecasts are different from one issue of EIA AEO to another (EIA, 2010; EIA, 2011; EIA, 2012; EIA, 2013; EIA, 2014). The drop in forecasted values can largely be explained by the introduction of new techniques for the extraction of resources that were not accessible before (shale gas). Similar comparison was conducted in another study that looks at the risk profile of the gas-fired plants (Bolinger et al., 2006).

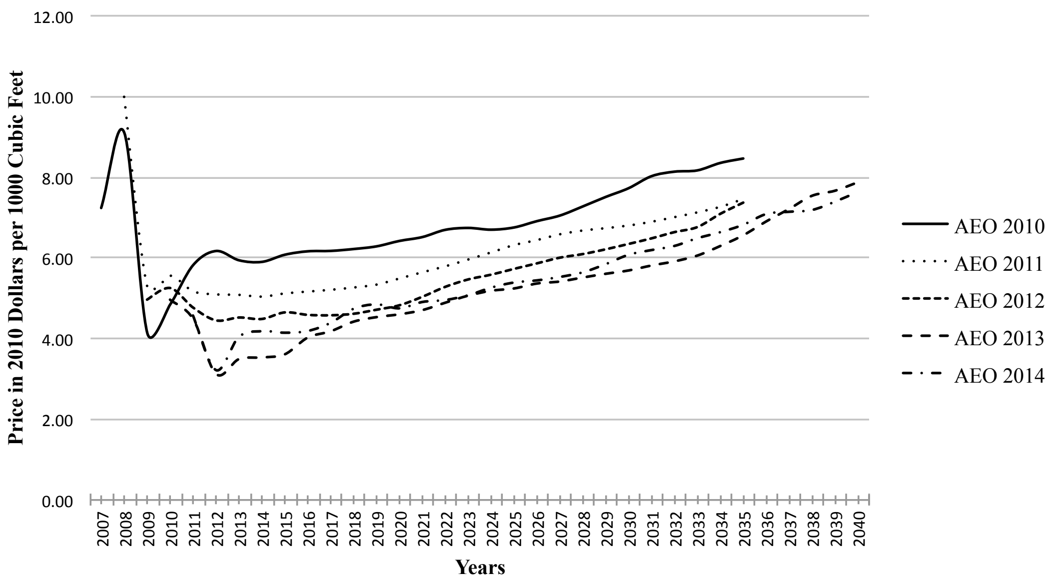

Figure 5: Forecast of natural gas prices delivered in the US for regulated power plants (EIA, 2010; EIA, 2011; EIA, 2012; EIA, 2013; EIA, 2014)

4.3.2 Fuel availability

The availability of fossil fuels, particularly natural gas, used to be an important issue in all markets. Fuel flexible power plants were quite common in Europe in the past (Söderholm, 2001) as the availability of natural gas was threatened by supply interruptions for various reasons. With the improvements in the delivery and storage systems, and the increase in the number of suppliers, this is no longer a major issue in liberalized markets. Consequently, fuel-flexibility is no longer an attractive instrument for power plants in the liberalized electricity markets.

In the emerging electricity markets, however, availability issues arising from supply constraints, security issues, and political conflicts remain a major challenge. The gas-fired power plants in Ghana, for instance, have been underutilized for years due to supply interruptions of natural gas from Nigeria (Mathrani et al., 2013). However, as discussed in the previous subsection, with fuel pass-through provision in the PPAs, the cost of this risk is entirely passed to the public party. Underutilization of power plants due to fuel supply issues will result in increased cost to the system and blackouts for the consumers.

The chance of supply interruptions mainly depends on the political and security status of the region. Increased number of suppliers in the region, improved transportation and storage facilities, political stability, and regional security will all reduce the chance of supply interruptions.

4.3.3 Electricity price

As explained earlier, the market price of electricity in liberalized markets is highly correlated with the cost of fossil fuels, natural gas in particular. IPPs can minimize their exposure to this risk by increasing the share of natural gas in their fuel mix (Roques, 2008). The price of electricity is fixed in the PPAs signed in the emerging markets. This is another provision to attract investors to such markets. The electricity price risk is therefore of no concern for the IPPs in emerging markets. However, if the utility is not earning enough to cover this cost, then the IPP agreement explicitly collapses.

In the analysis of the investments in power sector, the price of electricity can be forecasted based on the major investment plans in the energy sector and the expected shifts and reforms in the regulatory practice. The price of electricity could also be correlated with the price of fossil fuel; the degree of this correlation will depend on the market in question. Failing to factor for this correlation can result in an overstated variation in the outcomes of the analysis.

4.3.4 Electricity demand

Almost all the PPAs in emerging markets come with a take-or-pay agreement where the off-taker agrees to pay for a fixed amount of electricity even if it is not taken. In the liberalized markets, however, the cost of this risk is partially transferred to the IPP in rental agreements. To mitigate this risk, IPPs opt for a less capital-intensive technology (often peaking power plants), and secure alternative uses of their output such as third party sales or cogeneration.

Forecasting the demand for electricity can be viewed in different levels. First, the demand for electricity energy changes over time. It has been rising at different rates in most markets. Second, the shape of the demand for energy in a market during a given time interval, such as a year, can also change over time, from peaky to flat. Lastly, the system's demand from a particular power plant can have a completely separate path. The pricing strategies and the fuel prices affect the first two indicators of the market demand for electricity. The demand from a particular power plant not only depends on the overall demand from the system and its shape, but also depends on the competition it faces and shifts in the regulatory priorities.

4.4 Political and economic risks

4.4.1 Obsolescing bargain

The political risk for IPP projects in the emerging markets is well explained in literature (Woodhouse, 2005a; Woodhouse, 2005b). Once the investment is made by the IPP, the desperate nature of demand for investment in the infrastructure becomes obsolete and political pressure can force the PPA into renegotiations or even termination. In addition, introduction of IPPs is usually at the same time when regulatory reforms take place, very often coincided with a minor or major increase in electricity tariffs. The price increase initiates a public motion against the apparent changes at the surface of the sector, which are often the new private power producers.

Consequently, IPPs require multilateral guarantees before entering into PPAs in emerging markets. These guarantees are argued to have a limited impact in mitigating the political risk (Woodhouse, 2005b). Consequently, IPPs may turn into alternative ways of mitigating this risk such as overstating the investment costs of the project as explained in the next chapter.

Different institutions estimate and publish indicators for country risk periodically. These estimates use different methodologies and cover a limited number of countries and regions. Notable organizations are Fitch Ratings, Moody's, S&P, Economist Intelligence Unit, and The PRS Group, Inc. Many emerging economies may be excluded from these ratings or the comprehensive lists can be quite expensive to acquire. Alternatively, sovereign risk rating can be used as a good proxy for political and economic risks that can affect foreign direct investments (FDIs).

The political risk is not a significant source of risk for liberalized markets. IPPs in such markets may simply rely on government guarantees reflected in PPAs under “political force majeure”.

4.4.2 Foreign exchange

Similarly, the economic risks such the foreign exchange fluctuations are mainly an issue for IPPs in the emerging markets. Most of the investments in such markets are funded by foreign equity or loans, denominated in foreign currency. If the IPP relies on revenue from sales of the electricity in local currency, any drop in the value of the local currency can significantly threaten the financial viability of the project. To mitigate this risk, PPA payments are often specified in foreign currency or calculated using a fixed exchange rate, transferring this risk entirely to the public agent.

Financial markets and major banks can also provide insurance and contracts that would hedge against the exchange rate fluctuations. Either the IPP or the purchaser of the output can acquire such products to mitigate this risk. In the case of the high-risk developing countries, however, this risk is passed to the purchaser of the output.

4.5 Regulatory risk

The regulatory risks are defined as financial and technical stress on the power producer as a result of regulatory shifts in form of updated technical and environmental requirements. The degree of regulatory risk largely depends on the state of the reform in emerging markets and the existing set of requirements. In the absence of environmental restrictions for instance, one can expect the regulatory requirements to change over time to include required benchmarks on environmental impacts. This is not a concern in emerging markets as the PPA contracts protect the inventors from such risks. However, this remains a source of risk in liberalized markets, where IPPs use the instruments available in financial markets in order to insure themselves from such risks.

Chapter 5

OVERSTATEMENT OF INVESTMENT COST AS A RISK MITIGATION INSTRUMENT

5.1 Introduction

Most of the independent power producer (IPP) projects in high-risk developing countries have been financed through project financing arrangements where funds have been largely sourced from abroad (Woodhouse, 2005a). Such arrangements must focus on the management of financial risk in order to make the project bankable and attractive to private investors.

To attract private investors to high-risk markets, the public utility off-takes the output, pays for the fuel cost directly, and even indexes the payments in a foreign currency. These provisions are provided to an independent power producer (IPP) under a long-term power purchase agreement (PPA) (Gratwick & Eberhard, 2008; Hoskote, 1995).

Using the data from 41 combined-cycle power plants in 8 countries in Asia and the Middle East, Phadke (2009) showed that the stated investment cost of IPPs in developing countries is up to 50% higher in the absence of competitive bidding. As he noted, this does not necessarily mean that the introduction of competitive bidding can reduce the investment costs by 50%. Some countries are simply unable to attract investors into the electricity sector under competitive procurement processes.

This chapter provides a more systematic explanation for the tendency towards the overstatement of investment costs, with particular attention to the role of political and economic risk. Evidence provided here explains that the private investors turn to adding a markup on the investment cost to increase the actual return on the actual funds they put toward the project. This provision distorts the decision-making process, as the investment cost is an important input in long-term resource planning tools.

The overstatement of investment costs promotes the use of less efficient power plants, which increases the share of fuel as an input. This also increases the potential cost of mitigating the uncertainties around the fuel supply and its price. With a provision embedded in the PPAs stipulating that the fuel costs are passed through to the public utility, the cost of the additional fuel consumption and the uncertainties around fuel price and its availability are passed to the consumers in the form of higher prices. Therefore, the potential risk facing the IPP is mitigated, but at a significant social cost.

5.2 Risk management and the stated investment cost

To cover the cost of risk in partnerships with the private sector in infrastructure projects, governments and regulators often allow in their negotiations for a higher rate of return on equity. Despite this, most IPPs in less developed countries seek multilateral guarantees from organizations such as MIGA (Multilateral Investment Guarantee Agency) before entering into an agreement with local authorities. These provisions, among others, referred to as "risk engineering" by Woodhouse (2005a), are often insufficient to mitigate the risk and attract private investment in many situations.

Political justification is a major problem in increasing the target rate of return to equity in the agreement beyond a certain limit. These rates are stated in the contracts and can be compared with target rates of return for private investment in all other sectors in the economy. High target return rates on private investment make such contracts an easy target for those who would like to accuse the government of corruption, of being too generous, or of being unable to negotiate efficient deals. The usual victim in such cases is the IPP. In other words, increasing the risk premium into the target rate of return in the IPP contract above a certain threshold can backfire and further increase the political risk associated with the project.

The investment cost of power plants is made up of numerous items, many of which are project-specific. The estimation and comparison of some of these components by the regulators or financing institutions require the use of experts. Such information asymmetry exists in many regulated industries. PPAs are negotiated based on the stated investment costs put forward in the proposals submitted by the potential IPPs. If a satisfactory PPA can be negotiated to repay the financing for an overstated investment cost, this will allow for an increase in the absolute amount of borrowing. Therefore, the balance of the actual investment cost that is provided by the equity will become smaller than what the IPP would have contributed in the absence of an overstatement[4].

In the market for long-term power purchase agreements (PPAs), competition is only present at the bidding stage. Even then, only a limited number of bidders are present, and creating a competitive environment remains a challenge in many developing

[4] An inflated investment cost that is financed will allow the IPP owner to collect the margin upfront, usually through non-arms length construction contracts.

countries. Furthermore, if this is the way that all the bidders manage their risk, there is little reason why this investment cost markup will be reduced with more competition.

Phadke (2009) introduced the relationship between the return on equity and an overstated investment cost. Payments made to the IPP under a typical PPA will cover the investment cost, operating costs, financing costs, and a target rate of return on equity. If we put the operating costs aside, the actual return on equity (ROE_a) can be estimated based on the PPA payments (P_{PPA}) and the actual equity contribution (E_a) as shown in Equation 3.

$$ROE_a = \frac{P_{PPA}}{E_a} = \frac{(1-d)\times C_{PPA}\times ROE_{PPA}}{C_a - (d\times C_{PPA})} \qquad \text{Equation 3}$$

The payments made to the IPP (P_{PPA}) are calculated based on a fair rate of return specified in the contract (ROE_{PPA}), the share of debt in the financing arrangement (d), and the PPA's stated investment costs (C_{PPA}).

The amount of borrowing is normally defined as a percentage of stated investment cost and the equity contributes the balance. Therefore, the actual equity contribution (E_a) depends on the actual investment cost, excluding the markup (C_a), and the share of debt (d).

If the actual and stated investment costs (C_a and C_{PPA}) are equal, then the return on equity (ROE_a) will be exactly the same as the one reflected in the contract (ROE_{PPA}).

$$C_a = C_{PPA} \Longrightarrow ROE_a = ROE_{PPA} \quad \text{Equation 4}$$

If, however, the investors overstate the investment cost, the actual return on equity (ROE_a) will be different compared to the fair return stated in the PPA. An overstated investment cost affects both the nominator and the denominator of the fraction in Equation 3. If the investment cost is overstated by λ percent, as shown in Equation 5,

$$C_{PPA} = (1 + \lambda) \times C_a \quad \text{Equation 5}$$

then

$$ROE_a = \frac{(1 - d)(1 + \lambda)}{1 - d - d\lambda} ROE_{PPA} \quad \text{Equation 6}$$

The overstatement (λ) not only increases the stated equity contribution by $(1 + \lambda)$, it also reduces the actual contribution of equity by $d\lambda$ as the absolute amount of borrowing has increased proportionately to the overstatement of the investment cost. Table 4 shows this relationship under the assumptions that the contract guarantees a 20% rate of return on equity ($ROE_{PPA} = 20\%$) and debt covers 80% of investment (d=80%).

Table 4: Return on equity for different levels of markup on investment cost

	Markup on actual investment cost (λ) (1)	**Share of debt in actual investment cost ($d \times (1+\lambda)$) (2)**	**Actual return on equity (ROE_a) (3)**
1	0%	80.0%	20.0%
2	3%	82.4%	23.4%
3	6%	84.8%	27.9%
4	9%	87.2%	34.1%
5	12%	89.6%	43.1%

This formulation and example show that a slight overstatement of investment cost will have a considerable impact on the return on equity. From Table 4, row 5, we see that an overstatement of the investment cost by 12% will double the rate of return on equity. It is far easier to increase the return by overstating the "investment cost" rather than increasing the "cost of capital" in the PPA contract, which can easily be compared with other projects and hence create significant political risk.

As a result of this overstatement, the charges to the buyers of the electricity throughout the PPAs will be increased. The capacity payments to investors will be increased in absolute terms and, at the same time, the net financial contribution of the IPP owners will shrink. This results in a faster recovery of the actual amount of equity contribution that is a critical factor in determining the attractiveness of the project, as expressed by the payback period.

It is also important to note that such overstatements are not viable in the operating costs charged to electricity buyers. Maintenance costs are negligible in most power generation projects, and there would have to be a very substantial overstatement to make a difference. Fuel cost, although a large portion of the total cost for most thermal technologies, is treated mostly as a pass-through to the public utility. Even if it is a part of the energy payment to the IPP, the fuel cost is a function of the plant's total output, generation efficiency, and the market price of fuel, all of which are easy to measure and known by all stakeholders.

The end result is an increase in the cost of electricity to the country and an increase in the levels of finance required by the institutions financing the project. The country has to pay a higher price for the generation capacity, which in turn distorts their choice of technology and can result in an inefficient mix of inputs for electricity generation. Reliance on more fuel will lead to higher lifetime costs for the same amount of electricity generated. This is not a concern for the IPPs as the fuel cost is passed through to the distributors of the electricity. The IPP owners will recover their equity financing contribution at a faster pace. Table 4, row 6, reports that an overstatement of investment costs as low as 6% would reduce the share of actual equity financing from 20% to 15% of the total investment costs of the project and increase the rate of return on owner's net contribution to the financing from 20% to 27.9%.

5.3 Focus on thermal generation with gas turbine as the main mover

In this chapter, the variations in investment cost among IPP projects in developing countries are explored and an investigation is conducted to determine whether differences in country risk can significantly affect the stated investment cost. Phadke (2009) conducted a similar analysis focusing on the impact of the procurement process (competitive bidding vs. direct negotiations). The analysis presented here focuses on country risk. It is reasonable to assume that the procurement process is a weak proxy for country risk. Direct negotiations are often held when governments are unable to attract investors as a result of high levels of risk, or in the presence of corruption.

The analysis is performed on thermal power plants using gas turbines as the main generation technology. These power plants have become a popular choice for IPPs for a number of reasons. They provide operational flexibility, can be constructed for a wide range of capacities, work on various sources of fossil fuel[5], can be constructed in operational phases, and have a relatively short construction period. Many independently owned and operated thermal plants have been constructed in developing countries over the past two decades. This makes it easier to populate a dataset and conduct reliable statistical analyses.

The equipment cost of such open-cycle gas turbine (OCGT) or combined-cycle gas turbine (CCGT) power plants is a substantial element in their total investment. This component of costs is independent of the project's location[6]. There are only a handful of equipment manufacturers in this industry supplying all five continents with technically similar equipment[7]; hence, it is possible to analyze the variations in investment costs independently from the geographical location and technical details.

A thermal power plant with gas turbine as the main mover can take the form of an OCGT[8] or a CCGT. Combined-cycle plants are more fuel-efficient and, at the same time, more expensive than open-cycle plants. OCGT power plants and CCGT power

[5] Sources include natural gas, liquefied natural gas (LNG), heavy fuel oil (HFO), diesel, methane, and ethanol, among others.
[6] This is compared with hydro plants, for which the total investment cost largely depends on the geological characteristics of each particular site.
[7] Including GE, Siemens, Alstom, Alsando, and Mitsubishi, among others.
[8] Open-cycle plants are sometimes referred to as simple-cycle plants.

plants can convert about 35% and 55%, respectively, of the energy contained in fossil fuel into electrical power. The majority of the remaining energy is in the form of heat, which can either be exhausted into the environment or utilized for industrial or municipal heating.

5.3.1 Data

To complete the dataset, information is obtained on the following items:

- 72 OCGT and CCGT greenfield IPP projects in all developing countries (from 2000 to 2012)
- An estimate of turnkey price for each power plant in the sample based on its technical details and manufacturer
- A measure of country risk to represent the political and default risk of the country in the year when the project achieved financial closure.

The World Bank's Private Participation in Infrastructure (PPI) Project Database website[9] (referred to as the WB PPI in this study) is used as the main source of the initial list of projects and their basic information. Further technical details and turnkey contract prices are obtained from issues of the Gas Turbine World (GTW) Handbook from 2000 to 2012.

5.3.1.1 Projects

Projects that meet the following criteria are selected from the WB PPI database.

- Greenfield electricity generation projects (no transmission or distribution)
- Long-term PPAs (20±5 years)
- Gas turbine as the main source of power (CCGT or OCGT)
- Capacity of 100 megawatt or more
- Financial closure achieved between 2000 and 2012
- No specific technological challenges
- Information available on the technical details of the equipment.

[9] http://ppi.worldbank.org/

A large number of PPAs were signed during the 1990s in developing countries, particularly in Africa and Southeast Asia, that were later subject to controversies as a result of poorly designed contracts. This is why projects with financial closure prior to 2000 are excluded from this dataset. This limitation also allows for a more technologically homogeneous dataset while providing a sample size large enough to conduct econometric analyses (72 observations). A small number of projects are removed from the sample because there are no reliable sources to determine their technical details.

5.3.1.2 Variables

5.3.1.2.1 Cost

The investment cost of power plants is reported by the WB PPI database in current US dollars. The variable used in this study is the cost per kilowatt in 2010 US dollars, which is calculated by dividing the reported investment cost by the plant's capacity and adjusting to the 2010 price level using the US wholesale price index as reported in World Bank Data (World Bank, Accessed in September 2013).

5.3.1.2.2 Efficiency

The efficiency rating of a power plant can be measured and reported in various ways. This study uses a percentage reflecting the proportion of the fuel's total energy content that is convertible to electrical energy by the plant. For instance, a plant with 55% efficiency rating wastes 45% percent of its fuel's energy content (unless the remaining heat is utilized for industrial or municipal heating applications).

The efficiency of a plant depends on a number of factors, including the cycle type, size, ambient temperature, altitude, fuel type and quality, and the age of the plant. The cycle type and the plant size are already included in the model. To account for the remaining details, the efficiency rating of the units as reported by the GTW database is used.

5.3.1.2.3 Capacity

The capacity of a power plant is reported in megawatts. An important distinction must be made between the total capacity of a power plant and the capacity of each unit. A power plant may consist of one or several generation units. Larger units have a higher efficiency rating. For instance, efficiency ratings of above 60% are only available in CCGT units of 500 megawatts or larger. However, having multiples of the same units will not increase the efficiency rating of a plant.

Similarly, larger power plants tend to have a smaller cost per kilowatt as a result of economies of scale, even if they consist of multiples of small units. This is due to the fact that in larger projects the construction costs, consultancy fees, and other additional costs will be shared among several units. This being said, larger single units can also benefit from economies of scale on the main equipment costs. Both of these variables must be included in the analysis to explain plant costs as they affect the costs through different channels. In the work by Phadke (2009) only the total capacity of the plant is used as an independent variable. Unit capacity ($unitCapacity$) and the number of units ($unitCount$) are variables that are used in this study.

5.3.1.2.4 Alternative fuel

Aside from the standard features of the power plants as advertised by their manufacturers, a range of technical details can also affect their final investment cost. Storage tanks for backup fuel, liquid fuel transmission pipelines, carbon capture systems and NO_X reduction technologies, and fuel treatment facilities are all examples of technical equipment that are not among the standard features of all plants but can affect their investment costs. Capturing these details for each power plant in this study is not feasible, except in the case of dual-fuel compatibility. This common feature is used when there are uncertainties around the supply of the main fuel. Under such circumstances, plants can be equipped with storage tanks and pipelines for an alternative fuel to be used when the main fuel is not available.

The WB PPI database provides information about sources of fuel for power plants; additional details are obtained from other sources, including project reports and news pieces. The $altFuel$ variable is added in the form of a dummy variable, taking the value of 1 for plants that can operate on backup fuel and 0 otherwise.

5.3.1.2.5 Regional variations

Regional variations in investment costs can occur. Regions can differ in their experience with IPPs, transportation costs, skilled labor costs, and other factors that can affect the total cost of a power plant. Four regional dummies are introduced to capture these variations for the five regions in the data: Sub-Saharan Africa, the Middle East and North Africa, Latin America, South Asia, and East Asia and the Pacific.

5.3.1.2.6 Year

The investment cost of power plants can change over time. The real turnkey contract price of three popular CCGT units per kilowatt is presented in Figure 6. As can be seen, the constant dollar price of all types of generation plants rose sharply between 2005 and 2009, but abated somewhat after 2009. A financial closure year ($year$) is added to the analysis to capture any time trend in the real cost of production of such power plants.

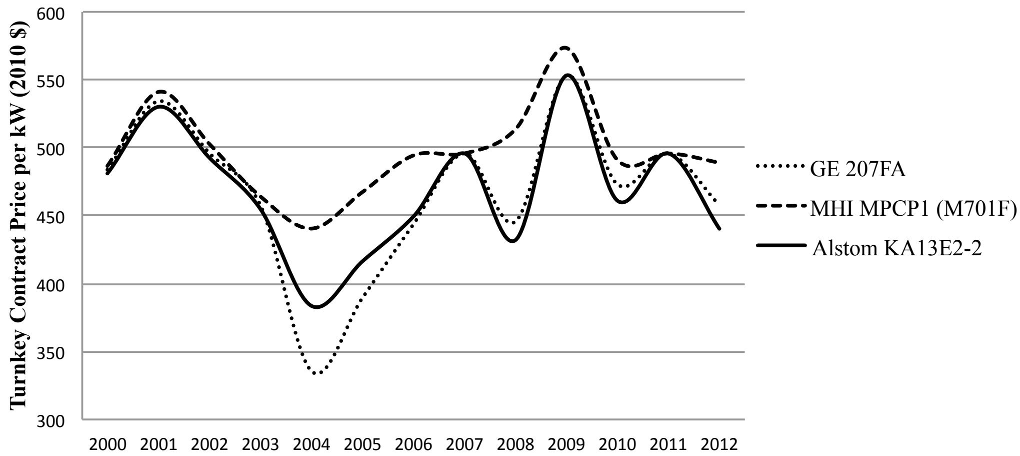

Figure 6: Turnkey contract price of typical power plants over time (source: http://industrialinfo.com/gas_turbine_world/)

5.3.1.2.7 Turnkey contract price

Industrial Info Resources hosts a database containing the information published in all editions of the GTW handbook[10]. This database includes benchmark turnkey contract prices for various technical configurations of power plants based on standardized location and surrounding details. According to the most recent GTW handbook (Farmer, 2013),

> The estimate includes basic plant design and engineering, turnkey equipment procurement and delivery, bulk materials of construction and non-union labor – but it narrowly sets the boundary limits such that they do not include utility grid interconnections, or any transmission lines, natural gas fuel pipelines, or service roads external to the plant site. (p. 46)

This estimate represents on average 65–70% of the total investment cost (Farmer, 2013). GTW also reports other technical details, such as the plant's capacity, configuration, and efficiency rating. This helps in both crosschecking the technical details for a second time and populating the dataset with information not available from alternative sources.

[10] http://www.industrialinfo.com/gas_turbine_world/

To locate the equipment used in a power plant at GTW, the unit model must first be identified. The World Bank PPI Database provides some basic technical details, including the capacity and dual-fuel compatibility; efforts are made to find the power plant manufacturer and number of turbines, and their gas-steam configuration, which are required for identification of unit models[11]. After the equipment details are identified, the turnkey contract price of each plant is obtained from the GTW handbooks for the period. In order to consider the price variations over the years, the turnkey contract price for each power plant is derived from the handbook that was published in the same year in which financial closure was achieved for the power plant. This variable is referred to as $gtwCost$ in this study and is reported in 2010 US dollars per kilowatt (2010 USD/kW).

A positive time trend is observed in the turnkey contract price from 2004 to 2009, and this is largely explained by the increase in the worldwide demand for CCGT and OCGT power plants.

5.3.1.2.8 Country risk

The final element to be considered, before regression models are constructed, is a measure of the country's political risk at the time of the financial closure for each project. Historical ratings data on the credit default swap, as published by Standard and Poor (Cavanaugh, Phua, & Young, 2013), represents a measure of risk that can

[11] This information was obtained from a wide range of sources including news reports, (LexisNexis - News & Business), The Global Energy Observatory website (http://globalenergyobservatory.org/), Power Plants Around the World website (http://www.industcards.com/ppworld.htm), Clean Development Mechanism (CDM) - The United Nations Framework Convention on Climate Change (http://cdm.unfccc.int/), and project reports published by financing institutions (African Development Bank, Asian Development Bank, and the World Bank), plant manufacturers, and major developers. In addition, Eberhard and Gratwick's article on IPPs experience in Africa (Eberhard & Gratwick, 2011a) helped in the crosschecking of the technical specifications and investment costs for the projects in Africa.

affect the financial performance of projects. The rating is published in letter grades for each country-year, from triple A (AAA) for the least risky environment to D for the worst conditions. Two ratings are published for each country-year, one for credits in local currency and another for credits in foreign currency. We assign a numerical value to each rating, from 1 for triple A, to 23 for D. The higher the number, the higher is the risk, and the risk rating for a country can be different from one year to the next.

There are alternative non-linear methods for assigning a numerical value for alphabetical risk ratings. However, the results of the statistical tests conducted as part of this study are not significantly affected by changing the conversion method. In order to have a measure that incorporates the risks around credit in both local and foreign currency, the linear average of the numerical value is used in the analysis ($avgRating$).

There are no foreign or domestic CDS ratings for Iran, Iraq, and Algeria; thus, the highest risk ratings available in the dataset are used for these countries (CCC+). This is the rating recorded for Pakistan in 2008 by S&P.

5.3.1.3 Data summary

The largest power plants in the dataset are two 1600 MW CCGTs installed in Thailand, each comprising two CCGT units of 800 MW. These are the largest and the most efficient units in the dataset. The two OCGT plants installed with a capacity of 125 MW in Ghana and Iraq exhibit the lowest efficiency rating in the dataset (33.8%). Table 5 presents the mean and standard error of some of the main variables, grouped by the region, cycle, and dual-fuel compatibility dummy variables.

Table 5: Mean and standard errors of key variables by region and type of generator

	Count (1)	$cost$ $(2010\$ /kW)$ (2)	$efficiency$ (%) (3)	$capacity$ (MW) (4)	$unitCapacity$ (MW) (5)	$gtwCost$ $(2010\$ /kW)$ (6)	$avgRating$ (7)
		Mean (standard error)					
Total	72	842.4 (223.1)	0.542 (0.05)	582.7 (374.1)	402.7 (190.5)	467.2 (118.4)	11 (3.13)
East Asia and Pacific	16	827.2 (250.2)	0.564 (0.03)	810.3 (497.8)	519.9 (235.5)	482.6 (109.3)	8.37 (1.85)
South Asia	21	888.8 (148.3)	0.547 (0.02)	395.8 (287.9)	305.1 (106.0)	518.0 (81.2)	12.4 (2.12)
Latin America & the Caribbean	22	796.5 (216.7)	0.560 (0.02)	574.1 (297.2)	433.4 (153.3)	478.1 (114.7)	9.56 (2.21)
Middle East & North Africa	9	817.7 (304.2)	0.461 (0.10)	659.2 (315.4)	291.5 (126.8)	343.6 (134.2)	14.8 (3.25)
Sub-Saharan Africa	2	1,193.0 (83.4)	0.430 (0.13)	288.0 (229.1)	288.0 (229.1)	335.5 (99.7)	13.2 (1.06)
Europe & Central Asia	2	762.5 (137.8)	0.578 (0.01)	769.0 (8.5)	769.0 (8.5)	394.5 (57.3)	13.5 (3.5)
CCGT	66	853.0 (214.0)	0.556 (0.02)	589.4 (380.7)	424.1 (184.1)	484.1 (100.5)	10.5 (2.84)
OCGT	6	726.0 (306.0)	0.381 (0.08)	509.1 (311.0)	168.3 (55.7)	281.8 (151.0)	15.8 (1.83)
Dual Fuel	27	874.1 (222.1)	0.515 (0.08)	531.3 (446.7)	351.7 (212.2)	462.4 (141.9)	11.3 (3.54)
Single Fuel	45	823.3 (224.0)	0.558 (0.03)	613.6 (324.6)	433.4 (171.5)	470.1 (103.5)	10.8 (2.88)

5.3.2 Regression equations

Five regression equations are used in this study. Three equations attempt to explain the cost per kilowatt ($cost$) of the plants. In the fourth equation, the proportionate cost of the markup of the plant over its turnkey contract price is explained. Finally, in the fifth equation the efficiency of the plant is explained in terms of the riskiness of the country in which it is located.

5.3.2.1 Cost per kilowatt ($cost$)

The first step in the analysis is to estimate three models with cost per kilowatt ($cost$) as the dependent variable. The investment cost of a power plant includes the following components.

- Main equipment and construction costs
- Time variant costs (escalation and interest during construction)
- Other equipment and construction for integration with the system
- Customized project-specific equipment
- Customized engineering, procurement and construction (EPC) services
- Owner's costs (land, permits, etc.)
- First fill of consumables.

Equation 7 is set up to explain the investment cost per kilowatt of the generation plants ($cost$), using as explanatory variables the technical efficiency ($efficiency$), unit count ($unitCount$), unit capacity ($unitCapacity$), cycle type ($OCGT$ dummy variable), and alternative fuel capability ($altFuel$ dummy variable) of the plants, as well as the regional dummies, and financial closure year ($year$). The initial tests reveal that only two of the regions, Sub-Saharan Africa and South Asia, exhibited significant differences and therefore the rest of the regional dummies are excluded from the models.

$$\begin{aligned} cost = \beta_1 + \beta_2 efficiency + \beta_3 unitCapacity + \beta_4 unitCount \\ + \beta_5 OCGT + \beta_6 southAsia \\ + \beta_7 subSaharanAfrica + \beta_8 year + \beta_9 altFuel \\ + e \end{aligned} \quad \text{Equation 7}$$

For the second regression, Equation 8, the average credit default swap risk ($avgRating$) is added as an explanatory variable to test whether the country risk can improve the fit and enhance the explanatory power of the regression.

$$\begin{aligned} cost = \beta_1 + \beta_2 efficiency + \beta_3 unitCapacity + \beta_4 unitCount \\ + \beta_5 OCGT + \beta_6 southAsia \\ + \beta_7 subSaharanAfrica + \beta_8 year + \beta_9 altFuel \\ + \beta_{10} avgRating + e \end{aligned} \quad \text{Equation 8}$$

In the third regression, Equation 9, an estimate of a turnkey contract price is included for constructing the same power plant in standardized settings ($gtwCost$) to account for the value of technical details other than the plant's efficiency rating[12]. However,

[12] Such technical details include operational flexibility, endurance, and maintenance requirements that are valued by operators and are not reflected in capacity and efficiency. The market price of the turnkey contract for the asset under standard

turnkey contract price is also affected by the unit's capacity (negatively correlated), and is therefore divided by the unit's capacity to arrive at a scale-free explanatory variable ($\frac{gtwCost}{unitCapacity}$). The efficiency is removed from the equation as its value is captured by the new variable.

$$cost = \beta_1 + \beta_2 \frac{gtwCost}{unitCapacity} + \beta_3 unitCapacity + \beta_4 unitCount + \beta_5 OCGT + \beta_6 southAsia + \beta_7 subSaharanAfrica + \beta_8 year + \beta_9 avgRating + \beta_{10} AltFuel + e \qquad \text{Equation 9}$$

5.3.2.2 Relative Markup ($relMarkup$)

To focus on the markup charged above the turnkey contract price, a new dependent variable is used in the fourth regression (Equation 11)[13]. In particular, we use relative markup, whereby the markup is calculated as a percentage of turnkey contract prices (presented in Equation 10). A relative markup ($relMarkup$) is independent of the scale of the unit; therefore, the $unitCapacity$ and $capacity$ are not expected to have any significant explanatory power over $relMarkup$[14]. However, a reduction in markup is expected when multiple units are installed in one power plant. The number of units is therefore added as an explanatory variable to this model.

conditions can capture the value of such features if we assume that the market is reasonably competitive.

[13] Phadke (2009) introduced the use of GTW turnkey contract price in his regression analysis. He calculated the difference between stated investment cost and GTW turnkey contract price to arrive at the residual cost.

[14] Their explanatory power is tested using a *t*-test in initial analysis and both prove to be insignificant, even at the 10% confidence interval.

$$relMarkup = \frac{cost - gtwCost}{gtwCost} \qquad \text{Equation 10}$$

However, to test the hypothesis that the markup is higher on less efficient plants, efficiency is included in the fourth regression model, presented in Equation 11.

$$\begin{aligned} relMarkup = \beta_1 + \beta_2 efficiency + \beta_3 unitCount + \beta_4 southAsia \\ + \beta_5 subSaharanAfrica + \beta_6 year \qquad \text{Equation 11} \\ + \beta_7 avgRating + \beta_8 altFuel + \beta_9 OCGT + e \end{aligned}$$

5.3.2.3 Efficiency ($\boldsymbol{efficiency}$)

Finally, efficiency is regressed by $unitCapacity$ and $avgRating$ to test whether the private operator will tend to opt for a less efficient, and hence cheaper, technology in riskier situations. The unit capacity ($unitCapacity$) captures the effect of scale on efficiency; it is important to include this variable as $unitCapacity$ is correlated with country risk ($avgRating$)[15]. Failure to include $unitCapacity$ would result in a biased coefficient estimate for $avgRating$. This regression model is presented in Equation 12.

$$efficiency = \beta_1 + \beta_2 unitCapacity + \beta_3 avgRating + e \qquad \text{Equation 12}$$

This regression is only performed on combined-cycle plants in the database. There is a considerable efficiency gap between the OCGT and CCGT power plants, and therefore a very significant correlation between efficiency and the cycle type. Inclusion of the OCGT plants in the dataset would result in the analysis suffering from heteroscedasticity and skewness.

[15] Correlation: −0.36 (95% confidence between −0.548 and −0.143).

In addition, the choice of technology (OCGT or CCGT) largely depends on the expected load factor of the power plant. The regression model would result in biased coefficient estimates in the absence of expected load factor if both technologies remain in its dataset. There are 66 CCGT observations, with efficiency ranging from a minimum of 49.7% to a maximum of 60.2%.

5.4 Analysis and results

5.4.1 Regression analysis results

Summary results of the three regression models explained earlier are presented in Table 6. The critical assumptions for linear regression models are tested for all the five equations. These tests include the normality of error term[16], linearity[17], heteroscedasticity[18], and multicollinearity[19]. The results of the tests significantly verify all the assumptions for the five equations (Breusch & Pagan, 1979; Jarque & Bera, 1987; Koenker, 1981; O'brien, 2007; Ramsey, 1969).

[16] Tested by the Jarque–Bera method for simultaneous test of Skewness and Kurtosis (Jarque & Bera, 1987).

[17] Tested by the Ramsey RESET test of functional specification (Ramsey, 1969).

[18] Tested using the studentized Breusch–Pagan test (Breusch & Pagan, 1979, Koenker, 1981).

[19] All five models pass the VIF test (variable inflation factor) at a cut-off value equal to 5, with the exception of efficiency in Model 2. However, the VIF of efficiency in Model 2 is still very small (5.09) and does not call for any remedies to correct for multicollinearity (O'brien, 2007).

Table 6: Results of the regression analysis

	Dependent variable:				
	cost (capital cost per kW)			relMarkup	efficiency
	(1)	(2)	(3)	(4)	(5)
efficiency	−667.624	26.029		−3.439**	
	(816.699)	(854.524)		(1.588)	
unitCapacity	−0.659***	−0.683***	−1.480***		0.0001***
	(0.157)	(0.153)	(0.348)		(0.00002)
unitCount	−51.319*	−55.729*	−50.354*	−0.063	
	(29.962)	(29.174)	(27.751)	(0.058)	
OCGT	−431.735***	−441.231***	−356.813***	−0.053	
	(158.910)	(154.420)	(118.927)	(0.307)	
altFuel	20.942	46.788	53.949	0.051	
	(52.078)	(51.952)	(47.079)	(0.103)	
southAsia	−94.721	−151.430**	−160.923***	−0.304**	
	(60.318)	(64.086)	(59.798)	(0.115)	
subSaharanAfrica	403.023**	410.513***	428.030***	1.287***	
	(155.166)	(150.761)	(139.977)	(0.300)	
year	1.913	2.222	4.890	0.025*	
	(6.724)	(6.533)	(6.257)	(0.013)	
avgRating		20.894**	25.029***	0.044**	−0.002**
		(9.567)	(8.635)	(0.019)	(0.001)
gtwCost/unitCapacity			0.002**		
			(0.001)		
Constant	−2,186.558	−3,388.128	−8,885.967	−48.628*	0.556***
	(13,388.090)	(13,016.280)	(12,534.160)	(25.350)	(0.014)
Observations	72	72	72	72	66
R^2	0.419	0.460	0.510	0.593	0.271
Adjusted R^2	0.345	0.382	0.438	0.541	0.248
Residual Std. Error	192.334 (df = 63)	186.825 (df = 62)	178.092 (df = 62)	0.372 (df = 63)	0.022 (df = 63)
F Statistic	5.676*** (df = 8; 63)	5.877*** (df = 9; 62)	7.160*** (df = 9; 62)	11.465*** (df = 8; 63)	11.728*** (df = 2; 63)

Note: *p<0.1; **p<0.05; ***p<0.01

5.4.2 Explaining the variation in cost per kilowatt

The first 3 estimated regression equations explain the variation in the investment costs per kilowatt. They are, in a way, reflecting the progress made in this study while trying to explain the variation in investment costs. The effect of adding and subtracting variables to these particular regression equations is, however, helpful in delivering some of the key findings of this study.

5.4.2.1 Analysis results in the absence of country risk

The first regression, presented in column (1) of Table 6, includes efficiency, unit capacity, unit count, cycle type, alternative fuel capability, time trend, and regional dummies as explanatory variables. This equation estimates a counterintuitive conclusion on the impact of efficiency on the investment cost of the power plant. Efficiency is found to have a negative impact on investment cost per kilowatts[20]. However, the industry shows that the more efficient plants are significantly more expensive (similarly, a strong correlation is found in our dataset between $efficiency$ and the turnkey contract price, $gtwCost$[21]). Adding the country risk as an explanatory variable in the second equation will address this issue.

As expected, as a result of economies of scale, the investment cost per kilowatt is lower for larger units or when multiples of a unit is installed. The results of the first regression equation (Table 6, column (1)) confirm that both the plant unit capacity and the unit count have significant explanatory power. Unit capacity and unit count explain the economies of scale that affect the core equipment costs and other investment costs, respectively. The coefficients estimated imply that, on average, the

[20] The analysis conducted by Phadke (2009) arrived at the same counterintuitive explanation of the sign of the coefficient estimated for efficiency.

[21] Correlation: 0.35 (with 95% confidence between 0.123 and 0.534).

investment cost per kilowatt is significantly lower by 0.66 US dollars and 51.32 US dollars for each megawatt increment in unit capacity and additional unit, correspondingly.

OCGT plants are technically simpler and less detailed than CCGT plants, reducing their infrastructure, transportation, and consultancy costs. As expected, the results of the first regression equation confirm that the investment cost is lower for an average open-cycle plant (431.73 US dollars less expensive per kilowatt for OCGT).

The results obtained from the first three regressions show that the investment cost of plants with dual-fuel compatibility is higher. However, this coefficient is not as significant as the other coefficients estimated by the regression models. This result can be partially explained by the fact that other technical features, such as emission control systems, are not included in this analysis.

As explained earlier, Sub-Saharan Africa and South Asia were the only two regions in which a significant impact on the cost of power plants was detected. Dropping the rest of the regional dummies implies that there must be irregularities in these two regions that would make them significantly different from the others. These differences must add extra information to what is already explained by plant characteristics, time trend, and the risk rating of the country.

Sub-Saharan Africa is the least developed electricity market in the world. The rate of access to electricity in this region is less than half the worldwide average. The potential for investment is great; however, despite the high levels of political risk, the limited regional experience and the inefficient transportation and transmission infrastructure make it even more difficult to attract investors. The results of the first regression equation (Table 6, column (1)), show that the investment cost of IPP projects per kilowatt in Sub-Saharan Africa is on average 403.02 US dollars higher than the developing world's average, even after adjusting for country risk and plant characteristics.

South Asia differs from the rest of the world in the other direction: the investment costs of IPP projects in this region are significantly lower, despite the poor risk ratings for the countries. India has the highest share of observations in this region. The country is one of the first in the developing world to host IPPs, providing it with significant experience in working with private investors, established and stable regulatory frameworks, and local financing and technical capacity for such projects. These advantages can spill over to neighboring countries. The calculated coefficient in the first regression equation for this region has the expected sign, but is insignificant. However, it becomes statistically significant with the same negative sign in the two subsequent regression equations.

All of the first three regressions indicate that, although statistically insignificant, there is a positive time trend in the real investment cost of IPP projects built in developing countries over the period 2000–2012.

5.4.2.2 Introduction of country risk as an explanatory variable

The second estimated equation (Table 6, column (2)) includes the average risk rating of the country ($avgRating$) as an additional explanatory variable. An intuitive coefficient (positive) is estimated for efficiency in the second regression equation.

Country risk ($avgRating$) and efficiency are negatively correlated[22], and both have explanatory power for the investment cost per kilowatt. Therefore, failing to include the country risk in the analysis would create a negative bias for the coefficient estimated for efficiency. The estimated coefficient implies that the investment cost of a plant per kilowatt is on average 26.03 US dollars higher for each percentage of efficiency, when all the other factors, including capacity, are held constant.

The results obtained for capacity, unit capacity, dual-fuel compatibility, time trend, and cycle types in the first regression equation are confirmed by the estimates of the second regression equation. This equation also confirms the estimates for regional dummies, yielding a statistically significant coefficient for South Asia. It is also important to note that the gap between the average stated investment cost of IPPs in East Asia and the rest of the world (except for Sub-Saharan Africa) increases from 94.72 to 151.43 US dollars per kilowatt after adding country risk as an explanatory variable.

In the second regression, the coefficient estimated for $avgRating$ (country risk) confirms the hypothesis that the investment cost is overstated by the IPPs when political or economic risks are threatening the project. The results imply that if the country risk is on a scale from 1 to 17 (AAA to CCC+), IPPs would overstate the investment cost of power plants per kilowatt by an average of 20.89 US dollars for every step of country risk. The coefficient is statistically significant at a 5% confidence interval.

[22] Correlation: −0.55 (with 95% confidence between −0.694 and −0.367).

5.4.2.3 Turnkey contract price

In the third regression equation (Table 6, column (3)) a variable is added to account for the value of all the technical details, not only efficiency. Calculated by dividing the turnkey contract price by the unit capacity, this variable is scale-free and allows for the unit capacity and unit count to remain in the equation as explanatory variables.

The third model shows that open-cycle (OCGT) plants are, on average, about 356.81 US dollars less expensive per kilowatt for an average plant size of 400 MW. The results obtained for dual-fuel compatibility, regional dummies, and time trend in the second regression equation are confirmed by the estimates of the third regression equation.

After adding the value of technical details of the plants through the turnkey contract price, the absolute size and statistical significance of the coefficient estimated for country risk increases. The results imply that if the country risk is on a scale from 1 to 17 (AAA to CCC+), IPPs would overstate the investment cost of power plants per kilowatt by an average of 25.03 US dollars for every step of country risk. The coefficient is statistically significant at a 1% confidence interval.

Replacing the plant's efficiency with a scale-free estimate of the turnkey contract price in the third regression significantly increases the goodness of fit. This confirms that the technical details, other than the efficiency, can considerably change the cost. The coefficient estimated for this variable is 0.002. Given that the average unit capacity is 402.7 MW, this means that an increase in the turnkey contract price translates to an almost equal increase in the investment cost of the plant (statistically significant at a 5% confidence level). However, since a major cost component ($gtwCost$) is included as an explanatory variable in this regression model, the explanatory power of the other variables is subject to challenge. To address this issue, the results obtained from the fourth regression, where the relative residual cost is the dependent variable, are used as the basis for commenting on the magnitude of the impact from the country risk and the explanatory power of the model.

5.4.3 Main findings from regression on relative markup

Despite the fact that the fourth regression (Table 6, column (4)) only explains the residual cost as a percentage of turnkey contract prices, it has a relatively high and very intuitive explanatory power. The results imply that if the country risk is on a scale from 1 to 17 (AAA to CCC+), IPPs would overstate the investment cost of power plants by an average of 4.4% of the turnkey contract price for every step of country risk.

A statistically significant, positive, time trend is estimated in the fourth regression. The time trend on residual costs can be explained if one assumes that more and more investors are considering the addition of a higher markup on investment cost as a risk mitigating measure. The results show that the markup on turnkey contract price has risen by an average of 2.5 percentage points a year. However, this can be caused by an overall time trend in the other costs not included in the turnkey contract price.

A study on IPPs' experience in the 1990s predicts that in the future, "The new IPP market is likely to be smaller in size and dominated by firms that have developed special political assets and management techniques that allow them to operate in uncertain (and, for many western firms, unfamiliar) electric power markets" (Woodhouse, 2005a, p. 8). In line with this conclusion, the coefficient estimated here reflects the fact that the new IPPs can manage to impose a higher markup on the turnkey contract price.

The coefficients estimated in the fourth regression for $\underline{unitCount}$, $\underline{OCGT}$ and $\underline{altFuel}$ are not statistically significant; however, their signs are as expected. The unit count was added to this model to estimate the economies of scale on the residual costs. As expected, a negative coefficient is estimated for unit count. The results indicate that the markup on turnkey contract price is an average of 6.3 percentage points lower for each additional unit of the same type in the power plant.

On average, the markup on turnkey contract price is estimated to be 5.3 percentage points lower for OCGT plants and 5.1 percent higher for plants that can work on a backup fuel.

The fourth regression equation confirms the conclusions drawn from the first three equations about the significant difference between the residual costs in South Asia and Sub-Saharan Africa compared to the rest of the world. The results indicate that the markup on core investment cost is 30.4% lower than the mean and 128% higher than the mean on average in South Asia and Sub-Saharan Africa, respectively.

The coefficient estimated for $\underline{efficiency}$ implies that under identical conditions, IPPs are able to charge a higher markup on less efficient plants. Most governments have average estimates for the per-kilowatt cost and efficiency of different power generation technologies including CCGT and OCGT thermal plants. Therefore, it is easier for the IPP to state a higher markup if it opts for cheaper, less efficient, equipment.

5.4.3.1 Efficiency and risk

The fifth regression equation confirms the hypothesis that the efficiency rating of plants in high-risk countries is lower, even after factoring for the scale effect. The results suggest that if the country risk were on a scale from 1 to 17 (AAA to CCC+), IPPs would opt for 0.2% less efficient CCGT technologies on average for every step of country risk. Note that this regression was performed on CCGT power plants only (66 observations) with an efficiency range from 49.7% to 60.2%.

Five steps of the average risk rating is not a great distance: it is the gap between Mexico in 2008 compared with Brazil in 2001. Turkey moved five steps upward from 2002 to 2011. Based on the coefficient estimated in the fifth regression (Table 6, column (5)), for such a gap the investors would opt for a CCGT power plant that is one percentage point less efficient, everything else held constant. While this may seem like a small difference, over the life of a 400 MW CCGT plant working at 80% load factor for 25 years, one percentage point drop in efficiency results in additional costs of fuel consumption that has a present value of 20 million US dollars[23].

5.5 Conclusions

The results of this study show that private sector IPP owners, in an effort to mitigate their risks in high-risk countries, have significantly increased the stated investment cost of proposed power generation plants. Furthermore, the private investors have an incentive to invest in power plants with lower technical efficiency, as the markups can be higher on plants with lower price tags. The practice of IPPs marking up the investment costs to mitigate the country risk means that electricity system planners

[23] The calculation assumes a fixed real price for natural gas (6 US$/MMBtu) and 10% economic discount rate. The test drops technical efficiency from 51.9% to 50.9%. All the dollar figures are in real 2010 US dollars.

are faced with distorted input prices that cause them to choose less efficient technologies in long-term system expansion planning.

With an increased investment cost, to compensate for the perceived cost of country risk, the system moves to less efficient power plants. This increases the cost associated with the fuel component of the system operating costs.

This analysis points towards the potential financial and economic benefits that could be realized through the use of political and country risk-management products offered by international and bilateral financial agencies to mitigate these risks in project financing arrangements of IPP investments. The process of providing these risk-mitigation instruments will need to be carefully sequenced so that the investment costs are reduced to reflect the effect of the risk mitigation. In the absence of competition it is conceivable that these risk-mitigation instruments would be acquired and the costs incurred by the consumers through higher PPA prices, while at the same time the private sector builds in compensation for these risks through higher capacity costs.

With reference to the results of this study, countries in Sub-Saharan Africa need to reconsider their technology choices and opt for better financial and technical arrangements in future thermal-generation IPP projects. Otherwise, in their efforts to meet the challenges of growing demand for electricity, the electricity system planners in these countries will be saddling their consumers or government budgets with high generation costs over future decades because of ineffective procurement and risk-mitigation strategies in their current dealings with IPPs.

Chapter 6

VALUE OF FUEL-FLEXIBILITY FOR POWER PLANTS IN SUB-SAHARAN AFRICA

6.1 Introduction

Combined-cycle gas turbines have become the technology of choice for medium to large-scale thermal power generation. The environmental impacts of coal plants, safety issues of nuclear plants, the relatively low price of natural gas, and the operational flexibility of gas turbines have all played an important role in promoting this technology (Kehlhofer et al., 2009; Roques, 2008). An attractive feature of combined-cycle gas turbine power plants is that they can operate on a range of fossil fuels. While natural gas is always the cleanest and most often the cheapest fuel option, it is not always available, and if available, its price will vary from one location to another.

Fuel-flexibility can be defined at the plant level or inside a portfolio of power plants (Söderholm, 2001). Each level has a different time and regulatory profile. Technological improvements have resulted in power plants that can switch from one fuel to another without interruption (Chase & Kehoe, 2000). Reconfiguration of an existing plant is a lengthier process and its possibility depends on the plant and fuel type (Kehlhofer et al., 2009). Both of these options are decisions that are made at the plant level, based on financial and risk incentives or regulatory obligations[24]. Unlike coal and nuclear power generation plants, gas turbines, in a combined-cycle or single-cycle configuration, can have fuel-flexibility built into their system or be reconfigured to permanently switch from one source to another.

The simplest form of substitution is between natural gas and distillate. Compatibility with Light Crude Oil (LCO) is more costly, or for some thermal plants impossible (Kehlhofer et al., 2009; Roques et al., 2008; Söderholm, 2001). Only conventional gas turbines can run on LCO, at an increased maintenance cost.

Multi-fuel plants were very popular in Europe until the 90s (Söderholm, 2001). This has changed as a result of developments in natural gas markets; increased storage and transportation infrastructure, improved access to a greater number of global suppliers in various forms (gas, compressed natural gas, and liquefied natural gas), and the development of financial markets to hedge against price fluctuations.

The reduced interest in multi-fuel plants in the European market is also attributed to environmental constraints on substituting gas, cost of maintaining backup, fuel switching costs, and short window of profit from price differentiation (National Grid, 2009). These challenges, however, are not all applicable to the conditions in Sub-Saharan Africa today. Improving the reliability of the system and its expansion are being given a much higher priority compared to environmental constraints. Furthermore, some have argued that any form of system expansion, even with diesel generators, can reduce the carbon emissions in countries like Nigeria where the

[24] Fuel diverse portfolios for utility companies and fuel diverse systems of generation are not discussed in this paper.

majority of households and businesses use small and inefficient generators to meet their needs for electricity[25].

Fuel-flexibility comes at an increased investment and maintenance cost, in return the system will benefit from increased generation reliability and, potentially, reduced fuel costs. In a poorly regulated market, investors in electricity generation may only see the costs associated with fuel-flexibility and not the benefits of it.

The regulation of power markets with private participation in electricity generation has been the objective of many developing countries over the past two decades. The final market outcome is, however, very different from one country to another. Promoting private participation in Sub-Saharan Africa has been a challenge. To attract private investors, governments commit to long-term take-or-pay agreements that transfer the risks associated with the fuel supply and its price to the public party. Under such arrangements, the investors have little or no incentive to invest in fuel-flexibility.

Vertical disintegration of the electricity system into generation, transmission, and distribution is pursued as a step towards a liberalized market. Many developing countries tend to stay in this step for an extended period of time. Under such circumstances, the price of electricity is often very politicized and rigid, making it difficult to adjust it for fuel cost variations. Therefore, the utilities are not provided with an incentive to maintain the ability to switch to an alternative fuel that would ensure continuous generation but at a higher cost of generation. Volta River

[25] http://www.cgdev.org/blog/how-can-nigeria-cut-co2-emissions-63-build-more-power-plants

Authority in Ghana, for instance, has come under increased financial stress since the interruption of its gas supply from Nigeria. It switched, where possible, to a more expensive fuel (Light Crude Oil) and has not been able to recover the additional cost of fuel through increases in electricity tariffs (Mathrani et al., 2013).

Most of the studies on the value of fuel-flexibility use some form of probabilistic analysis, however they are more focused on liberalized markets such as the United States and Europe. Some (Roques, 2008; Spinney & Watkins, 1996) use Monte Carlo simulations to evaluate the performance of electric utilities and power plants, factoring for fluctuations in price of fuel. Roques estimates the results under three different contractual scenarios from the operator's perspective and finds combined-cycle gas turbines as the right choice of technology for private operators in liberalized markets, over coal and nuclear (Roques, 2008).

Other studies look at the short-term degree of substitution among fuels, at the plant, portfolio, and the system levels (Söderholm, 2001), the value of fuel-flexibility inside a portfolio of power plants (Roques et al., 2008), the use of a Mean-Variance Approach (MVP) for a portfolio-based planning of the electricity generation system (Awerbuch, 2006; Vithayasrichareon & MacGill, 2012), and multi criteria diversity analysis for appraising energy portfolios (Stirling, 2010). The studies mentioned above are mainly concerned with fluctuations in the fuel price, the regulatory shifts accommodating climate change policies, and the integration of renewables, issues that are more important in liberalized markets. Many of the policy parameters are quite different in high-risk markets.

To attract private investors to high-risk markets, the public utility off-takes the output, pays for the fuel costs, and even indexes the payments in a foreign currency. These provisions are provided to an independent power producer (IPP) through a long-term power purchase agreement (PPA) (Gratwick & Eberhard, 2008; Hoskote, 1995). Such PPAs do not closely resemble the common regulatory frameworks observed in more developed, or less risky, markets.

This paper uses a cost-benefit analysis framework to draw policy conclusions on investment in fuel-flexible thermal plants under two scenarios. First, a framework is constructed to assess the decision where natural gas is the primary source but its availability is subject to supply interruptions. Second, a situation is analyzed where natural gas is subject to supply constraints; however, there are prospects of domestic supply or import availability in the future.

These scenarios are applicable to countries with limited access to secure and reasonably priced natural gas markets. Most of the countries of Sub-Saharan Africa (SSA) fall into this category. Nigeria is currently the only major exporter of natural gas in the region. The supply of natural gas from Nigeria, however, has frequently been interrupted due to various security issues within or outside Nigeria, resulting in supply levels short of its stated capacity. Ghana has recently discovered pockets of natural gas and plans to start production within the next 5 years. As demand for electricity is rising, studies show that the domestic supply of natural gas will soon fall short of the demand by electricity generators (Mathrani et al., 2013). Therefore, reliance on alternative sources of fuel will remain an option for addressing forecasted and unforeseen shortfalls of natural gas.

Another example is Cyprus; the close proximity of this island to Turkey has led some private investors to propose an investment in an undersea transmission line to bring electricity from Turkey. Because of Turkey's access to natural gas the cost of generation is lower in Turkey that in Cyprus. At the same time natural gas has been discovered off the shores of Cyprus and it is expected in the foreseeable future to be available to the electricity generators. The prospect of domestic natural gas would lower the cost of electricity generation and reduce the potential benefits from the proposed investment in the transmission line.

The analytical framework discussed in this study relies on the integrated approach to investment appraisal. In this approach, one financial framework is constructed to reflect all the transactions, reflecting the final impact on the economy as a whole (Jenkins et al., 2011).

6.2 Framework 1: Natural Gas as the primary fuel subject to availability issues

The availability of primary fuel is a concern where the number of suppliers is limited. Potential gains from taking advantage of price differentials are excluded from this framework. This helps in simplifying the equations at no cost to the empirical or policy conclusions. The window of opportunity is very short for benefiting from price differentials (Söderholm, 2001) as the prices of oil and natural gas tend to be correlated in the long run (Bencivenga & Sargenti, 2010; Villar & Joutz, 2006). In addition, it is unlikely that in the near future light crude oil (LCO) will become competitive with natural gas for electricity generation from a price standpoint.

6.2.1 Incremental costs

Pipelines, liquid fuel treatment equipment, and storage tanks are required for dual or multi fuel operation of a gas turbine. The current generation class of gas turbines can switch from gas to liquid fuel and back without an interruption in their generating load (Chase & Kehoe, 2000), however their variable maintenance cost increases when they operate on liquid fuels (Oppong-Mensah, 2014). The maintenance cost associated with using liquid fuel is often indexed according to the density and other characteristics of the liquid fuel in the form of a multiplier to the base cost of maintenance when using natural gas as fuel.

In most markets, the cost of liquid fuels per MWh of electricity is higher than that of natural gas; therefore an increase in fuel cost must also be factored in. Lastly, the storage of liquid fuel increases the working capital requirements of the operation and is another incremental cost to include in the analysis.

To correctly estimate the incremental cost of maintaining and operating a fuel-flexible plant with natural gas as the primary fuel, the present value of increased investment for fuel flexibility[26] (i), additional maintenance cost ($\dot{m}$), backup fuel cost ($\dot{f}$), and increased working capital requirements ($\dot{w}$) must be incorporated. Note that these values are the present value of a stream of flows for every period over the life of the power plant. For instance, the change in maintenance cost would be the sum of the discounted changes in each period ($\dot{m}_t$) as expressed in Equation 13.

[26] This value will be net of the present value of any incremental residual value from the additional equipment and storage facility.

$$\dot{m} = \sum_{t=0}^{n} \frac{\dot{m}_t}{(1+r)^t} \qquad \text{Equation 13}$$

Where t is the indicator for the period and r is the discount rate applied over each period. Incremental working capital requirement ($\dot{w}$) is calculated as the sum of the present values of changes in the real value of liquid fuel that is stored at the site per MW of capacity. Since the variation in fuel price and impacts of inflation are not included in this analysis, the change is zero during the operational periods, except for the first and the last periods, as long as the volume of fuel stored at the site per MW capacity remains constant. This formula is shown in Equation 14.

$$\dot{w} = \sum_{t=0}^{n} \frac{\dot{s}_t p_{LCO}}{(1+r)^t} = p_{LCO}\left(\dot{s}_0 + \frac{\dot{s}_n}{(1+r)^n}\right) = p_{LCO}(s - \frac{s}{(1+r)^n}) \qquad \text{Equation 14}$$

Where $\dot{s}_t$ is the change in volume of fuel stored at the plant site per MW of capacity at each period, s is the volume of fuel store per MW of capacity, and p_{LCO} is the price of liquid fuel per unit of volume.

6.2.2 Incremental benefits

In a deterministic study where the expected value of gas supply is equal or above the required amount (=>100%), there are no benefits from fuel-flexibility. With an expected availability below the require amount, however, the benefits can surface in form of averted supply interruptions.

The availability of gas is a contingent variable; it can be more, or less, than the required amount. However the capacity of the plant is limited so having an excess supply of gas does not affect the supply of electricity. The plant's capacity places a cap on the generation of electricity. It is only a shortage of gas that can affect electricity generation. Unlike variables such as the fuel price, the variation in gas availability would affect the expected outcomes only negatively, reducing the expected output of the project.

In the valuation of the benefits from fuel-flexibility, it is important to highlight the difference between the unsupplied power from a power plant and undelivered power to consumers by the system. These two are not always equal. The system may be able to absorb some of the interruption by increasing the load on other less efficient plants (often older plants used for reserve). Running these plants more can partially replace the unsupplied energy. However, it comes at an increased cost to the system. Depending on the terms of the power purchase agreement (PPA) these additional costs can be transferred to the independent power producer (IPP) in form of operational penalties. No such penalties are applicable, however, in the case of PPAs with a fuel pass-through provision.

The benefit from averted supply interruptions is therefore shared among the consumers (from averted blackout), electric utility (from reduced financial and technical stress), and independent power producer (from averted penalties or reduced costs, if applicable). This is study is focused on the investment environment in Sub-Saharan Africa; therefore the latter benefit is not applicable.

The incremental benefits for each period would be calculated as the incremental value of averted shortages per MWh (λ) times the total number of hours that the supply of gas is interrupted in that period (h_t)[27]. The incremental value of averted shortages (λ) depends on the willingness to pay of the consumers to avoid blackouts and the backup cost for other plants. Often the cost of blackouts to consumers (λ^b) is greater than the cost imposed on the system to backup the supply (λ^s) to the degree it can. Incremental benefits (B) from reducing such fuel shortages can be calculated as shown in Equation 15.

$$B = \sum_{t=0}^{n} \frac{h_t \lambda}{(1+r)^t} = \sum_{t=0}^{n} \frac{h_t[(1-\alpha)\lambda^s + \alpha\lambda^b - c_e]}{(1+r)^t} \qquad \text{Equation 15}$$

Where, c_e is the cost of grid-supplied electricity under normal fuel conditions and α is the share of interrupted supply that results in blackout.

6.2.3 Number of hours when supply of gas is interrupted (h_t)

This variable is a critical parameters in the model which is calculate as:

$$h_t = (1 - \mu_t)\gamma_t \qquad \text{Equation 16}$$

Where μ_t is the realized availability of gas for period t, and γ_t is the expected capacity factor in period t. To simplify the analysis, it is assumed the plant is used for baseload and faces a fixed demand by the system per year (γ). The number of

[27] Since the analysis is incremental, the marginal cost of the electricity to the economy is no longer entering the framework directly. However when calculating the benefits from averted interruptions, this cost must be deducted from the opportunity cost as one should only look at the incremental benefits. For instance, if the cost is 12 Cents per kWh and the loss as measured by the willingness to pay by consumers for the unsupplied electricity is 40 Cents per kWh, one can only attribute 28 Cents per kWh as the benefits to be gained by the economy from averting supply interruptions. Please note that the cost of electricity for the economy can be different from the tariff paid by the consumers. Subsidies are regularly applied to the electricity tariffs in many countries.

hours with interruption is also required to calculate the change in the maintenance cost ($\dot{m}$) and the change in the fuel costs ($\dot{f}$) as shown in Equation 17.

$$\dot{m} = \sum_{t=0}^{n} \frac{M_g \beta_{LCO} h_t}{(1+r)^t}$$

$$\dot{f} = \sum_{t=0}^{n} \frac{f_{LCO} h_t}{(1+r)^t}$$

Equation 17

Where M_g is the benchmark maintenance cost when running on natural gas, β_{LCO} is the multiplier[28] for maintenance for liquid crude oil (LCO), and f_{LCO} is the fuel cost per MWh of electricity output for each MW of capacity.

6.2.4 Net benefits

The net benefits from fuel-flexibility ($\dot{B}$) per Megawatt of capacity can be estimated by deducting incremental costs from incremental benefits (B) as shown in Equation 18.

[28] As a rule of thumb, maintenance cost of the gas turbine increases by 50% and 100% on distillate oil and LCO, respectively, implying multipliers of 1.5 and 2 for these two liquid fuels (Oppong-Mensah, 2014).

$$\dot{B} = B - \left(i + \dot{m} + \dot{f} + \dot{w}\right)$$

$$= \sum_{t=0}^{n} \frac{h_t \lambda}{(1+r)^t} - i - \sum_{t=0}^{n} \frac{M_g \beta_{LCO} h_t}{(1+r)^t} - \sum_{t=0}^{n} \frac{f_{LCO} h_t}{(1+r)^t} - \sum_{t=0}^{n} \frac{\dot{s}_t p_{LCO}}{(1+r)^t} \qquad \text{Equation 18}$$

$$= \left[\sum_{t=0}^{n} \frac{\left(\lambda - M_g \beta_{LCO} - f_{LCO}\right) h_t - p_{LCO} \dot{s}_t}{(1+r)^t}\right] - i$$

Where

$$h_t = \begin{cases} (1-\mu)\gamma, & 0 < \mu < 1 \\ 0, & \mu \geq 1 \\ \gamma, & \mu \leq 0 \end{cases} \qquad \text{Equation 19}$$

With this framework, one can substitute values for the parameters and obtain the net benefits. In a deterministic case, where the expected availability of natural gas is equal or more than the amount required by the plant, fuel-flexibility would result in a net economic loss. However, with continuous problems in the supply of natural gas in most of Sub-Sahara Africa, it is quite reasonable to consider the chance of supply interruption.

The expected benefits from fuel flexibility depend on the expected number of hours when the supply of gas is interrupted (h_t), and the economic value of averting these interruptions (λ). Estimating these values requires statistical analysis, forecasting, and market analysis. In order to simplify the analysis, one can estimate a breakeven point equation for h_t, where the benefits and cost of fuel-flexibility are equal, and see the sensitivity of this breakeven point ($\acute{h_t}$) to different value of λ. The breakeven point can be estimated by equating Equation 18 to zero as presented in Equation 20.

$$\left[\sum_{t=0}^{n} \frac{(\lambda - M_g\beta_{LCO} - f_{LCO})\acute{h_t} - p_{LCO}\dot{s}_t}{(1+r)^t}\right] - i = 0$$

Equation 20

$$\acute{h_t} = \frac{\left[\sum_{t=0}^{n} \frac{p_{LCO}\dot{s}_t}{(1+r)^t}\right] - i}{\sum_{t=0}^{n} \frac{(\lambda - M_g\beta_{LCO} - f_{LCO})}{(1+r)^t}}$$

6.3 Framework 2: Prospect of future domestic supply

Proven reserves of natural gas may remain untapped for years, or even decades, due to political and technical complexities, uncertainties about the size of the reserve, inadequate export facilities, and fluctuating international prices of natural gas. Examples include countries of Kenya, Ghana, and Cyprus. The first question, relevant to this study, is whether to invest in fuel-flexibility for planned thermal plants or not. Most of the cost associated with fuel-flexibility is for having liquid fuel as the secondary source. Such costs include the storage, treatment, and the increased maintenance cost. Where liquid fuel is initially the primary source, such costs are already in the picture and reconfiguration to burn natural gas comes at very low costs.

6.3.1 Costs for a fuel-flexible thermal plant

The total cost per megawatt of capacity for a single-fuel thermal plant (using LCO) is presented in Equation 21.

$$C_{th}^{sf} = \sum_{t=1}^{n} \frac{R_{th} + \gamma\left(\beta_{LCO} M_g + f_{LCO}\right) + p_{LCO}\dot{s}_t}{(1+r)^t} \qquad \text{Equation 21}$$

Where C_{th}^{sf} is the total cost per megawatt of capacity for a single-fuel thermal and R_{th} is the rental or annualized investment cost of the assets. The rental cost can be calculated based on the investment cost of the thermal plant (i_{th}), the life of the assets (n), and the required rate of return (r) as presented in Equation 22.

$$R_{th} = \frac{i_{th} r (1+r)^n}{(1+r)^n - 1} \qquad \text{Equation 22}$$

With prospect of domestic natural gas, Equation 21 can be expanded to show the cost for a fuel-flexible plant (C_{th}^{ff}) as presented in Equation 23.

$$C_{th}^{ff} = \sum_{t=1}^{j-1} \frac{\gamma(\beta_{LCO} M_g + f_{LCO})}{(1+r)^t} + \sum_{t=j}^{n} \frac{\gamma(M_g + f_g)}{(1+r)^t} + \sum_{t=1}^{n} \frac{p_{LCO}\dot{s}_t + R_{th}}{(1+r)^t} \qquad \text{Equation 23}$$

$$0 < j \leq t$$

Where C_{th}^{ff} is the total cost per megawatt of capacity for fuel-flexible thermal plant and j is the expected point in time when domestic gas is available to the plant. The benefits from fuel-flexibility are shown in Equation 24.

$$C_{th}^{sf} - C_{th}^{ff} = \gamma \left[\sum_{t=j}^{n} \frac{(\beta_{LCO} - 1)M_g + (f_{LCO} - f_g)}{(1+r)^t} \right] \qquad \text{Equation 24}$$

As the cost of this provision is marginal, savings from fuel-flexibility that arises from reduced maintenance and fuel costs, $(\beta_{LCO} - 1)\ M_g$ and $(f_{LCO} - f_g)$ respectively, are expected to promote the provision even if the expected period for utilizing natural gas (from j to n) is short. Please note the present value of change in working capital remains the same under both configurations. The assumption here is that the plant remains fuel-flexible even after natural gas becomes available. This is a reasonable assumption as fuel-flexibility increases the reliability of the system and, in this case, comes at no additional investment cost. In case of secure supply of natural gas, the operator may choose not to maintain liquid fuel reserves to reduce the working capital requirements. Under such conditions the benefits from fuel-flexibility will further increase.

6.4 Results

The cost-benefit analysis frameworks presented in the previous section can be used for decision making on the investment in fuel-flexible thermal power generation plants when the supply of gas is unreliable, or when there is prospect of natural gas.

6.4.1 Unreliable supply of natural gas

Whether the investment in fuel-flexibility is worthwhile for a thermal power plant with natural gas as its primary fuel depends on a number of critical parameters. The number of hours when it is expected that the supply of gas be interrupted (h_t) is one. In most markets, operators are aware of the average number of hours or days that their gas supply is interrupted in a year. There are various ways to construct a probability distribution for this variable. However, one can solve the equation for the minimum number of interruption hours that would justify the investment in fuel-flexibility.

The other critical parameter is the value of averted interruption, which depends on the willingness to pay of the consumers to avoid blackouts and the backup cost for other plants. Many studies have attempted to estimate the cost of lost supply per kWh of electricity to households and businesses of different sizes. The estimates, in multiples of electricity tariff, range from 4 to 90 times (Foster & Steinbuks, 2009; Layton & Moeltner, 2005; Ozbafli, 2012; Tollefson, Billinton, Wacker, Chan, & Aweya, 1994). For a conservative estimate, one can take the lower value of 4 times the cost of electricity generation. The cost of generation could be equal to the electricity tariff paid by the consumers if the tariffs are cost-reflective. The cost imposed to the rest of the generation fleet will depend on the type of plants that can be utilized for backup. One can assume that (α) is close to 100% in countries like Ghana where the generating fleet is short of demand and most plants are fully utilized at all times.

6.4.1.1 A numerical example

Data obtained on Ghana for a typical combined-cycle with 400MW of capacity with two GE frame 9E gas turbines and a steam turbine. The summary of values is presented in Table 7.

Table 7: Parameter values for the example on the value of fuel-flexibility

Indicator	Value	Unit (all per MW of capacity)	Reference/Description
λ^b	480	2014 USD/MWh	Source: Africa Infrastructure Country Diagnostic Power Tariff Database (4 times the tariff of 7.6 US Cents/kWh)
c_e	120	2014 USD/MWh	Source: http://www.ecgonline.info Assumption: the tariff is cost-reflective
α	100%	%	Assumption: interruptions result in equal amount of undelivered electricity to consumers
M_g	3.6	USD/h	U.S. Energy Information Administration, Updated Capital Cost Estimates for Electricity Generation Plants April 2014.
β_{LCO}	2	#	Personal communications (Oppong-Mensah, 2014)
f_{LCO}	122.72	USD/MWh	Based on advertised efficiency of 49% (Oppong-Mensah, 2014), and LCO price of 109 USD/Barrel (www.energycom.gov.gh)
γ	7,884	Hours	Based on 90% capacity factor for a baseload plant
p_{LCO}	109	USD/Barrel	www.energycom.gov.gh
$\dot{s_t}$	650	Barrels	For a 31,000 m3 storage facility (Oppong-Mensah, 2014)
r	12	%	Assumed economic discount rate for Ghana
t	20	#	Assumed life of the combined cycle plant
i	32,500	USD/MW	Personal communications (Oppong-Mensah, 2014), salvage value of the additional equipment is assumed to be zero.

Please note that a conservative assumption of 4 times the tariff is made about the cost of interruptions in supply at the consumer side. This assumption has a number of underlying discussions. First, the consumer tariff is not cost-reflective in the case of Ghana. Therefore, the actual cost of the blackouts must be greater than 4 times the tariff and the assumption used here a conservative one.

Second, although the cost of electricity generation may be similar from one country to another, willingness to pay for increased reliability could be very different based on the income level, reliance on electricity powered appliances and equipment, and the reliability of the system. One could argue that these factors would result in a lower willingness to pay for reliability in Ghana compared to many other countries.

Final point here is about the perspective of stakeholders. The difference between the willingness to pay and the tariff for electricity is a net gain for the consumers resulting from averted blackouts. This benefit is, however, partly a transfer from the government in form of the subsidies paid on electricity tariffs. The net economic benefit should not include this subsidy and is calculated as the difference between the willingness to pay by the consumers and the economic cost of electricity generation.

To reduce the impact of this assumption on the outcomes of the analysis, the electricity tariff is used as a measure of the generation cost for the system.

Solving the equation shows that the investment in fuel-flexibility is economically feasible for any levels of expected interruption above 327 hours per year. This is about 14 days of disturbed gas supply. The economic losses in the absence of fuel-flexibility provisions can amount to a present value in excess of 50 Million Dollars over the life of a 400MW plant if the supply interruption continues for only 3 extra days per year in the same period (total of 17 days per year). This loss is about 4 times the additional investment required to convert the plant into a fuel-flexible one.

To show how the results can change with a less conservative estimate for the willingness to pay to avoid blackouts, the break-even number of days is estimated for different levels of willingness to pay (Equation 20), see Figure 7.

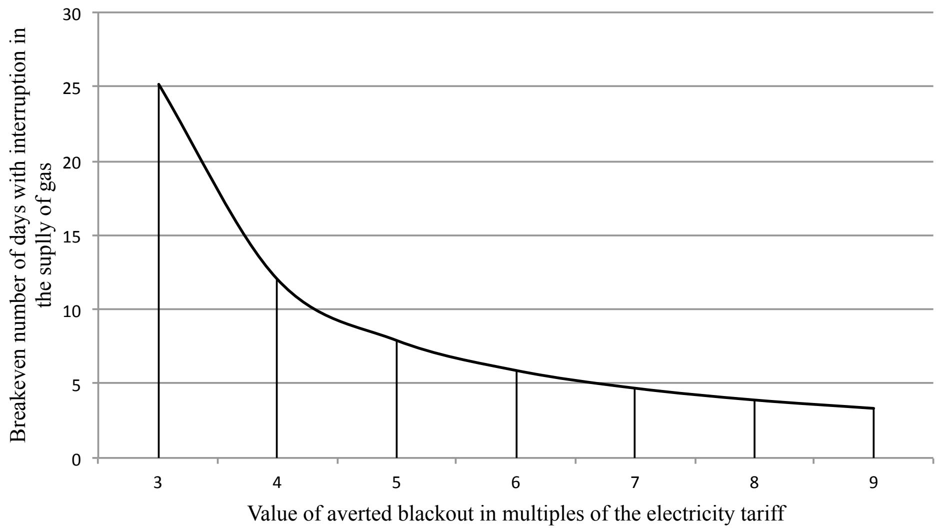

Figure 7: Breakeven number of hours with interruption in the supply of natural gas for different estimates for the value of averted blackouts

6.4.2 Prospect of future domestic supply of natural gas

The second framework presented a framework for calculation of the value of fuel-flexibility when liquid fuel is the primary fuel source and there is prospect of future domestic supply, or access to cheap international sources. As a part of this analysis, a framework was constructed (Equation 23) to estimate the cost of electricity generation using a fuel-flexible thermal plant. This equation shows how the prospect of future access to a cheaper fuel alternative can reduce the cost of thermal generation when it is being compared with other means of generating or importing electricity. The reduction in the total cost of the thermal plant can equally be expressed as a reduction in the benefits of the alternative technologies that are unable to use natural gas.

The reduction in cost of thermal generation will depend on the cost of liquid fuel, the expected timing of access to natural gas, and the cost of natural gas. These parameters can significantly change the final decision as a significant drop in the cost of thermal makes it quite competitive with alternative such as hydro or international transmission lines.

6.5 Discussion

Fuel-flexibility measures can result in significant economic benefits when the supply of gas is threatened by the slightest interruptions, or when there is prospect of future access to natural gas. It is important to see if the policies that govern the electricity generation systems provide the correct incentives for investment in such provisions.

The majority of power plants in Sub-Saharan Africa are owned and operated by incumbent, vertically integrated, public utilities, or independent power producers (IPPs). The IPPs are regulated by long-term power purchase agreements (PPA). A typical PPA in Sub-Saharan Africa would implement a cost-plus regulation scheme with fuel pass-through provision, where the risks associated with fuel supply and market demand are all transferred to the public entity. Such contracts are needed to attract private sector investment into high-risk markets.

6.5.1 Decision making when faced with unreliable supply of natural gas

6.5.1.1 Vertically integrated public utility

Integrated utilities have the right incentives to insure reliability and are normally responsible for all costs including the fuel. However, the price of electricity, set by the regulator or the utility itself, is often politicized in developing countries and very rigid. Reliance on an alternative fuel is associated with a significant increase in fuel costs; utility companies that are unable to reflect this cost on the tariff will find themselves under financial stress. This financial stress can eventually result in substantial deficits if the reliance on alternative fuel continues for a long period. Volta River Authority, Ghana, is a good example (Mathrani et al., 2013).

A politicized and rigid tariff setting mechanism is a common issue in most countries in Sub-Saharan Africa and works as a barrier to improvements in the sector. Under such conditions, the public utility is faced with a trade-off between reliability and financial stability. As subsidies are not favored and financial independency is highly promoted for public utilities, it seems logical to opt for financial stability and maintain the status quo.

6.5.1.2 IPP model

PPAs in Sub-Saharan Africa come with full cost-recovery provisions, therefore, in theory; the IPP must be indifferent with respect to fuel-flexibility provisions. All the incremental costs (investment, fuel, working capital, and maintenance) are simply passed through as increased PPA payments. Therefore, private participation in these markets does not address the incentive issue that arises from politicized and rigid electricity tariffs.

Furthermore, market incentives in emerging electricity markets result in a tendency towards power plants that require a smaller investment cost (Kashi, 2014; Phadke, 2009; Wamukonya, 2003). Fuel-flexibility is a technical feature of a power plant that comes at increased investment requirements. Under such circumstances, the IPP and the system planner have an incentive avoid any additional investment costs such as fuel-flexibility.

6.5.2 Decision making when faced with prospects of future access to natural gas

The choice between the fuel-flexible power generation plant and an alternative means of supplying electricity, such as a hydro dam or an international transmission line, is more of a decision to be made by the system planners. However, policies such as the promotion of private participation can significantly affect the investment environment. These policies result in market distortions and biased input parameters for the planning process.

The future supply of natural gas can significantly reduce the cost of thermal generation compared to other sources of electrical energy. The expected value of these reduced thermal electricity generation costs is equivalent to a reduction in the benefits of an alternative electricity generation technology whose primary benefits is the cost avoidance of generation with fossil fuels.

6.6 Conclusions and policy recommendations

Investment in fuel-flexible power plants can be an economically attractive option in a range of situations. This chapter provides an analytical framework for evaluating the feasibility of such investments when access to natural gas is subject to unforeseen interruptions or there is prospect of future supply of natural gas.

Ghana is a good example where 80% of the country's current thermal capacity is fuel-flexible (Mathrani et al., 2013). This flexibility has also resulted in placing a major financial stress on the state-owned generation company (Volta River Authority). It has been operating its fuel-flexible fleet on the more expensive fuel option (LCO) for some years but the wholesale tariffs do not reflect this additional cost. On the other hand, the only single-fuel grid-scale plant, Sunon Asogli, has been underutilized in the same period as a result of the supply cut-off of natural gas from Nigeria. Due to the large capital investment incurred, the utilization of thermal power plants below their planned capacity factor results in a significant economic loss.

Using a numerical example from Ghana, it is estimated that for a 400MW conventional combined-cycle gas turbine power plant, the net economic savings from investment in a fuel-flexible power plant can amount to 50 Million US Dollars over the life of the plant (20 years). This estimate uses a conservative measure for both the value of averted blackouts and the expected number of days with interruptions in the supply of gas (about 17 days per year). At the same time, even with such conservative inputs, the net economic savings is about 4 times the required investment for fuel-flexibility.

The market model can distort this decision making process, state-owned power plants have a disincentive for fuel-flexibility when they are faced with politicized and rigid electricity tariffs. Private participation could only make this worse as it promotes the use of more fuel intensive technologies.

The frameworks presented in this study can be used as a decision making process from an economic perspective. However, the final decisions for such investments are highly impacted by a range of factors. Political and regulatory environment, private participation in power generation, international relations, and the conditions of the public utility are among the elements that can significantly change the parameters for decision makers. Therefore, the final investment decision can be different from the least cost option. Power generation projects have large investment outlays and such decisions create operating inefficiencies that are likely to result in a significant economic loss.

Chapter 7

CONCLUSION AND POLICY IMPLICATIONS

7.1 Challenges faced by the countries of Sub-Saharan Africa in promoting private investment

This thesis explored some of the challenges faced by the countries of Sub-Saharan Africa in improving the performance of their electricity generation markets. The electricity markets of these countries are suffering from similar problems, including the shortage of generation capacity, inadequate transmission and distribution infrastructure, politicized prices, unreliable access to fuel, and young regulatory bodies. These factors form an investment environment where the costs of private participation may exceed its benefits.

Mitigation techniques used by the IPPs faced with high levels of country risks, and the lack of incentives for investments in fuel-flexibility were determined as barriers to efficiency gains from private participation.

7.1.1 Overstatement of investment cost

To attract IPPs into these markets, buyers of electricity have to provide generous contracts to private investors. Despite the risk mitigating provisions included in the PPAs, the evidence provided in chapter 5 show that the investors' behavior is still largely affected by country risk. As they find the conventional risk mitigation mechanism insufficient to fully address the level of country risk observed in these countries, investors turn to overstate the investment cost of these projects. This overstatement increases the return on investment and shortens the payback period at a significant cost to the economy.

The statistical analysis was conducted on 72 IPP projects that arrived at financial closure between 2000 and 2012 in developing countries. The results imply that if the country risk is measured on a scale from 1 to 17 (AAA to CCC+), IPPs would overstate the investment cost of power plants by an average of 4.4% of the turnkey contract price for every step of country risk. Furthermore, it was shown that as this risk mitigation technique promotes the use of less efficient technologies, IPPs would opt for 1 percentage point less efficient[29] CCGT technologies on average for five steps of the country risk. Five steps of the average risk rating is not a great distance: it is the gap between Mexico in 2008 compared with Brazil in 2001. Turkey moved five steps upward from 2002 to 2011. While this may seem like a small difference, over the life of a 400 MW CCGT plant working at 80% load factor for 25 years, one percentage point drop in efficiency results in additional costs of fuel consumption that has a present value of 20 million US dollars[30].

7.1.2 Lack of incentives for investment in fuel-flexibility

The uncertainties around the supply and availability of natural gas promote the use of fuel-flexible power plants. The economic benefits from fuel-flexibility arise from increased reliability and potential cost savings.

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[29] Thermal efficiency

[30] The calculation assumes a fixed real price for natural gas (6 US$/MMBtu) and 10% economic discount rate. The test drops technical efficiency from 51.9% to 50.9%. All the dollar figures are in real 2010 US dollars.

Chapter 6 provides an analytical framework for evaluating the feasibility of such investments when access to natural gas is subject to unforeseen interruptions or there is prospect of domestic supply of natural gas. The value of fuel-flexibility will depend on the uncertainties around the supply of natural gas, its cost, and the cost of the alternative.

Using a numerical example from Ghana, it is estimated that for a 400MW conventional combined-cycle gas turbine power plant, the economic savings from investment in a fuel-flexible power plant can amount to 50 Million US Dollars over the life of the plant (20 years), or roughly 4 times the investment required for fuel flexibility.

The models presented in chapter 6 can assist the decision making process from an economic perspective. However, the final decisions for such investments are highly impacted by a range of factors. Political and regulatory environment, private participation in power generation, international relations, and the conditions of the public utility are among the elements that can significantly change the parameters for decision makers. Therefore, the final investment decision can be different from the least cost option. Power generation projects have large investment outlays and such decisions can result in significant economic losses.

7.2 Conclusions for policy makers and planners

7.2.1 More informed investment decisions

Designing efficient contracts and understanding the behavior of parties to these contracts are critical factors in the success of market reforms in benefiting from a competitive environment. Oftentimes these policies and investment decisions are strongly influenced by the national and foreign politics. It is however critical for the decision makers to know the financial and economic consequences of these decisions. Wrong choice of technology can result in inefficient use of resources over a long period of time and hence extensive losses for the economy.

7.2.2 Better negotiations and contracting with private investors

The analysis presented in chapter 5 points towards the potential financial and economic benefits that could be realized through the use of political and country risk-management products offered by international and bilateral financial agencies to mitigate these risks in project financing arrangements of IPP investments. The process of providing these risk-mitigation instruments will need to be carefully sequenced so that the investment costs are reduced to reflect the effect of the risk mitigation. In the absence of competition it is conceivable that these risk-mitigation instruments would be acquired and the costs incurred by the consumers through higher PPA prices, while at the same time the private sector builds in compensation for these risks through higher capacity costs.

7.2.3 Promoting better policies

Major international donors and credit agencies have advocated for market reforms in Sub-Saharan Africa with the objective of promoting private participation. Given the varying outcomes and limited impacts from these reforms, it has become clear that the costs associated with private participation can surpass the benefits of it in some markets. A more careful market analysis, improved risk mitigation, and consideration of alternative means of investment in this sector can address some of these challenges. Private participation through long-term PPAs may not be the most optimal mean of improving the performance of electricity sector in this region in its conventional form.

Given the outcomes observed in Africa since the urge in the 1990s, one wonders if the new constraints attached to funds made available by major donors, such as limiting the financing credits to renewable (wind and solar) project only, would be another poorly designed policy. This can be seen as a topic for another research project that could utilize some of the analytical frameworks developed in this thesis.

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