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Generating Power and Controversy: Understanding Tanzania's Independent Power Projects

Katharine Gratwick, Rebecca Ghanadan and Anton Eberhard

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University of Cape Town Graduate School of Business
Breakwater Campus
Private Bag
Rondebosch 7701
Cape Town, RSA

www.gsb.uc.ac.za/mir

The Management Programme in Infrastructure Reform & Regulation (MIR) strives to be a leading centre of excellence and expertise for Africa and other emerging and developing economies. Based at the University of Cape Town's Graduate School of Business, MIR aims at enhancing understanding and building capacity to manage reform and regulation of infrastructure sectors, in support of sustainable development. MIR's main focus at present is in the electricity and water sectors, but growth is expected in gas, transport and potentially in telecommunications. MIR works on three fronts, providing: executive and professional short courses; research related to the frontiers of infrastructure reform and regulation in Africa; and professional support and policy advocacy.

Author biographies

Katharine Nawaal Gratwick
Senior Researcher, Management Programme in Infrastructure Reform and Regulation
Graduate School of Business
Tel: + 27 21 406 1361
Fax: + 27 21 406 1070
Email: gratwick@gsb.uct.ac.za

Katharine Nawaal Gratwick, a senior researcher with MIR in Cape Town, leads the Programme's survey of Independent Power Projects (IPPs) throughout Africa, including detailed case studies in Egypt, Kenya and Tanzania (completed in 2005) and Nigeria, Morocco and Tunisia (expected in end-2006). Katharine Nawaal has worked previously with the World Bank's Energy Sector Management Assistance Program (ESMAP) and the Oil, Gas, Chemicals Division as well as Poten & Partner's Liquefied Natural Gas (LNG) team, based in Washington and New York, respectively. Most recently, she served as a business consultant with KPMG in the United Arab Emirates. Ms. Gratwick obtained her M.A. in International Energy Management and Policy from Columbia University in New York.

Rebecca Ghanadan
PhD Candidate, Energy and Resources Group
University of California, Berkeley
Tel: +1 510 524 5139
Fax: +1 510 642 1085
Email: rghanadan@berkeley.edu

Rebecca Ghanadan is a PhD candidate in the Energy and Resources Group at the University of California Berkeley. Her studies and research focus on the nexus of energy and society in development, service provision, and infrastructure policy. Rebecca has evaluated power sector reforms and energy policy in developing and OECD countries with the World Bank's Energy Sector Management Assistance Program (ESMAP) and the Nautilus Institute for Security and Sustainable Development in Berkeley, California. Rebecca has also worked extensively on household energy, access to services, and renewable energy in East and West Africa. Currently, Rebecca is completing her dissertation on electricity reforms in Tanzania.

Anton Eberhard
Director Management Programme in Infrastructure Reform and Regulation
Graduate School of Business
Tel: + 27 21 406 1361
Fax: + 27 21 406 1070
Email: eberhard@gsb.uct.ac.za

Professor Anton Eberhard directs the Management Programme in Infrastructure Reform and Regulation at the University of Cape Town's Graduate School of Business. He is a former Board Member of the National Electricity Regulator of South Africa. His research and teaching focuses on the restructuring and regulation of the electricity sector and linkages to sustainable development issues such as widened access to services, and investments in renewable energy and energy efficiency. He has worked in the energy sector for more than 20 years and was the founding Director of the Energy and Development Research Centre. Anton has more than 70 publications to his credit and has undertaken numerous assignments (both locally and abroad) for governments, utilities, regulatory authorities, and donor and multi-lateral agencies. Professor Eberhard has a PhD from the University of Edinburgh.

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Abbreviations and acronyms

AFUDC	Allowance for Funds Used During Construction
BOT	Build Operate Transfer
BOO	Build Own Operate
CDC	Commonwealth Development Corporation
COD	Commercial Operation Date
DEG	German Investment & Development Company
DFI	Development Finance Institution
EIB	European Investment Bank
EPC	Engineering Procurement and Construction Contract
ESI	Electricity Supply Industry
ESMAP	Energy Sector Management Assistance Program
EWURA	Energy and Water Utilities Regulatory Authority
FDI	Foreign Direct Investment
FMO	Dutch Development Company
GDP	Gross Domestic Product
GJ	Gigajoule
GoT	Government of Tanzania
GWh	Gigawatt hours
HFO	Heavy Fuel Oil
IPTL	Independent Power Tanzania Limited
ICSID	World Bank's International Centre for Settlement of Investment Disputes
IDA	World Bank International Development Association
IFC	International Finance Corporation
IPP	Independent Power Project
IPS	Industrial Promotion Services
KILAMCO	Kilwa Ammonia and Urea Company
km	kilometer
kWh	Kilowatt hour
LNG	Liquefied Natural Gas
MEM	Ministry of Energy and Minerals
MMBtu	Million British Thermal Unit
mmscfd	million standard cubic feet per day
MW	Megawatt
Norad	Norwegian Agency for Development Cooperation
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbines
ODA	Official/Overseas Development Assistance
PESD	Stanford University's Program on Energy and Sustainable Development
PPA	Power Purchase Agreement
PSRC	Parastatal Sector Reform Commission
REA	Rural Energy Agency
REF	Rural Energy Fund
ROE	Return on equity
SAPP	Southern African Power Pool
Sida	Swedish International Development Cooperation Agency
SS1	Songo Songo well 1 (SS1-9)
TANESCO	Tanzania Electricity Supply Company Limited
TD	Transfer Date
TDFL	Tanzania Development Finance Company Limited
TPDC	Tanzania Petroleum Development Corporation

Tsh	Tanzania Shilling
USAID	United States Agency for International Development
USc	United States cent
USD	United States Dollar
UGT1	Ubungo Gas Turbine 1 (1-6, I-VI)
VAT	Value Added Tax
VIP	VIP Engineering Limited
WDI	World Bank's World Development Indicators

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Executive Summary

Initially conceived of within the broader context of power sector reform in the late 1980s and early 1990s, Independent Power Projects (IPPs) were intended to relieve state utilities of the burden of financing new plants, bring quick, quality power and reduce costs for end-users. Although IPPs have indeed contributed to generation, much of the power that resulted from investments has been supplied neither quickly nor cheaply. Quality of supply issues have often also not been addressed as power sector reforms have not materialized as expected. Many projects were and remain today the subject of controversy.

Embarking on power sector reform in the early 1990s, Tanzania made IPPs a pillar of its reform strategy. Presently, Songas and IPTL, the country's two IPPs are helping to reduce load shedding. However, these projects have not been without controversy. One of Tanzania's IPPs (IPTL) was taken to international arbitration over a dispute related to construction costs (and resulting high electricity purchase cost). The other accrued cost-overruns from project delays that increased project costs by 50% and required additional restructuring of capacity payments.

In 2006, the state electric utility, Tanzania Electric Supply Company Limited (TANESCO), paid 96% of current revenue towards combined fuel and capacity charges for the IPPs (despite the fact the IPPs accounted for only 55% of the power generation). With twenty-year Power Purchase Agreements (PPAs) between IPPs and TANESCO, these costs are long-term parts of sector finances (albeit with some potential modifications due to refinancing, fuel conversion and further development of the natural gas market).

IPPs are also significant to wider national state-level finances. IPP capacity charges are equivalent to approximately one percent of GDP. The Government of Tanzania (GoT) has intervened to assist TANESCO with its monthly IPP payments. IPP costs have also contributed to the need for a large scale loan to TANESCO, after IPP generation costs dramatically restructured sector costs and TANESCO required outside assistance.

Introduction of IPPs has been one of sole elements of restructuring actually implemented from Tanzania's power sector reform plan. The state utility remains vertically integrated, with control over nearly the entire sector. An independent regulator was introduced in 2006, however this was negotiated after new emergency power and the large IPP deals were sealed. The new utility regulator has, however, played a direct role in negotiating new tariff increases, as electricity generation shifts to greater IPP use and costs.

One change, not initially considered in the reform program, was a management contract for the state utility, after TANESCO failed to meet its financial and technical targets. This contract, which spanned 2002-2006, ushered in a host of changes, but ultimately did not pave the way for privatization as was originally intended. TANESCO has reverted to state control and at least for the time being, privatization is not being actively discussed.

This report provides a detailed summary of how and why IPPs developed in Tanzania as well as their impact to date. Development outcomes, namely the extent to which the host country is benefiting from reliable, affordable power, and investment outcomes, the degree to which investors have made favourable returns and been able to expand market share, are analyzed in turn.

They key lessons that emerged from the paper are:

- The importance of power sector planning coordination;
- The necessity of power sector reform priorities;
- The critical nature of an independent regulator to increase efficiency and transparency;
- The value of competitive bidding and following recognized processes for procuring new power;
- The potentially time consuming nature of arbitration and ultimate impact on overall power sector development;
- The need to carefully consider the type of private investor, particularly with evidence of high equity turn-over; and

- Finally, the potential impact of currency devaluation and the role of local capital markets.

IPPs offer more than a decade of experiences in private sector investment in developing countries and a detailed understanding of them may be the key to unlocking and sustaining future power investment.

1. Introduction

The story of Independent Power Producers/Projects (IPPs) in developing countries is not a simple one. Initially conceptualized within the broader context of power sector reform, these projects were intended to relieve state utilities of the burden of financing new plants, bring quick, quality power and reduce costs for end-users. Actual implementation of projects has, however, been intertwined with controversies, delays, and debates over costs of power. In many developing countries, IPPs did not lead to either quick or cheap power. Additionally, several IPPs were negotiated with the aim of alleviating immediate crises and needs, and were often only loosely connected to sector reform plans and policy models. In numerous cases, IPPs have been a lightening rod of national and international debate and have led to rethinking of reform policies and the role of private sector participation by both advocates and critics of IPPs. A number of IPP projects globally have also either been re-negotiated or cancelled. IPPs offer a critical opportunity to glean lessons for reform and private sector participation in the power sector. The success, failures, and nuances of IPPs help in understanding what private sector participation may and may not do for Africa.

Tanzania is among the African states that have embarked on extensive programs of power sector reforms and IPP development. Unlike many elements of Tanzania's reform plans in the 1990s, such as establishing a regulator, restructuring the sector, and privatising the utility, the introduction of independent power projects (IPP) is one of the few pieces that materialized. Tanzania's Electricity Supply Industry, characterized by persistent state-ownership and control, has been transformed by the addition of two IPPs. Prior to the inception of IPPs, nearly 80 per cent of power was provided by hydropower; in contrast, between 2002 and 2006, thermal power accounted for about 60 per cent of generation, which was almost exclusively generated by IPPs. Benefiting from new thermal capacity, Tanzania was among the few East African countries able to avoid substantial load shedding. However, in early 2006, drought conditions eroded Tanzania's hydro capacity beyond what the IPPs could provide, and the country resorted to extensive load shedding in February 2006, which continued throughout all of 2006, amounting to approximately 100 megawatts (MW).[1] [2]

[1] Tanzania's neighbours (Uganda, Burundi, Rwanda) all resorted to load shedding between 2002 and 2006, a period which coincided with severe drought in the region. Tanzania was able to make up this difference with IPPs (although outages due to the failure of transmission and distribution were frequent). In early 2006, under continued drought conditions, hydro shortfalls reached larger levels than IPPs could make up, and Tanzania also began load shedding. Load shedding reached 12 to 18 hours per day in many areas of the country in February 2006 and continued throughout the year, despite IPPs running at full capacity.

[2] Throughout 2007, IPPs/thermal power accounted for only about 20 per cent of total generation due to the return of normal hydrological conditions. There has been no load shedding recorded in 2007.

Tanzania is a particularly important case for understanding IPP development and investment outcomes for Africa. Notable aspects of Tanzania's IPP programme include: IPPs making extensive contributions to the electricity supply industry (ESI), the Government of Tanzania's early efforts to adopt reforms, the major contribution of IPPs to reduce load shedding, the controversial nature of the IPP costs and development process, and the Government of Tanzania's (GoT) intervention to assist Tanzania Electricity Supply Company Limited (TANESCO), the state utility, with its monthly payments. Tanzania's IPP experience also offers the opportunity to examine the role of different stakeholders in the IPP process, including government and private sponsors—both local and foreign—together with the involvement of multilateral development institutions, such as the World Bank. Additionally, the Ministry of Energy and Minerals (MEM) is considering developing additional IPPs.[3]

This paper examines the way in which Tanzania's IPPs evolved as well as the impact on stakeholders. Development outcomes, namely the extent to which the host country is benefiting from reliable, affordable power, and investment outcomes, the degree to which investors have made favourable returns and been able to expand market share, are analyzed in turn. Based on interviews with key stakeholders,[4] this paper also draws on a review of policy documents and reform literature, and an assessment of project outcomes from utility and IPP data. Further resources for the paper include findings from a global study of IPPs[5] and companion IPP case studies in other African countries undertaken by

[3] References to both Government of Tanzania (GoT) and Ministry of Energy and Minerals (MEM) are made repeatedly throughout the paper. While MEM is part of GoT, it should be noted that explicit reference to GoT implies that stakeholders may have included, but were not limited to those, in MEM.

[4] Over 30 interviews were conducted with more than 20 stakeholders in January, February, August, November and December 2005 in Dar-es-Salaam, Washington D.C. and via teleconference in London. Interviews were followed by email correspondence to clarify discussion points, with the last review of data conducted in September 2007. Stakeholder interviews included present and former directors and managers at Artumas Tanzania (Jersey) Limited (ATJL), Orca Exploration, IPTL, Songas, EWURA, MEM, PSRC, TPDC, VIP, TANESCO, NETGroup Solutions, Sida, and the World Bank. *Due to sensitivity of data, the names of stakeholders, who have been the primary source of data for this paper, have largely been left out of the discussion; most stakeholders are only identified, if at all, by organizational affiliation in the text. As a result, much of the data, which forms the basis of this paper, is not cited. In certain instances, however, where stakeholders have indicated their willingness, citations do include names and the designation of "per com" for personal communication.*

[5] The paper is part of a global IPP study, led by Stanford University's Program on Energy and Sustainable Development (PESD), which includes detailed reports on twelve different countries. The overarching purpose of the study is to evaluate the IPP experiences across a number of countries and projects and thereby glean best and better practices for the future. See http://pesd.stanford.edu/docs/ipps.php for information on PESD IPP study.

the Management Programme in Infrastructure Reform and Regulation (MIR) at the University of Cape Town.[6]

The authors adopted an inductive research approach, initially conducting a review of reform and project documents, followed by meeting with stakeholders. Conclusions were drawn from the evidence examined and assessment of broad lessons gleaned from Tanzania's IPP experience. The details presented on IPPs and reforms were confirmed across a range of sources. Any errors and omissions are the responsibility of the authors.

2. Tanzania's two main IPPs: IPTL and Songas

Tanzania developed two main IPPs over the last decade.[7] Together, they contribute approximately 300 MW, or about one third of the country's present generation capacity of 1005 MW (inclusive of emergency power as of May 2007). In terms of energy sold, as of 2006, Tanzania's IPPs were contributing over half of the electricity generation, and represented the main source of thermal (non-hydro) capacity. Starting in 2007, however, with the resumption of normal hydrological conditions, IPP contribution dropped to about one third of total production.

Independent Power Tanzania Limited (IPTL) was the first IPP to begin to sell electricity to the national electric utility. An independently negotiated IPP among Malaysian investors, a local Tanzanian firm and the GoT, the construction of IPTL was completed in 1998, but IPTL started producing power only in January 2002, after a three year delay resulting from a dispute over construction costs and related capacity payments. The 100 MW diesel plant consists of 10 medium-speed units of 10 megawatts each, which presently run on imported HFO. Eventual conversion to domestic natural gas has been intended for IPTL since its original PPA and is expected in the near-term.

[6] This paper forms part of a broader assessment of African IPPs undertaken by MIR that goes beyond those studies included in the Stanford PESD analysis. The authors of this paper have also been co-authors of studies on Morocco (Malgas, Gratwick and Eberhard, 2007a) and Tunisia (Malgas, Gratwick and Eberhard, 2007b). Forthcoming are studies on Cote d'Ivoire (Malgas 2007c) and Ghana (Malgas 2007d). In addition, an as of yet unpublished survey of Nigerian IPPs was conducted by the authors of this paper in collaboration with researchers at the Centre for Energy Research and Development at Obafemi Awolowo University in Ile-Ife, Nigeria. Further information on the MIR IPP research may be found at http://www.gsb.uct.ac.za/gsbwebb/default.asp?intpagenr=309.

[7] Several small self-producers have also sold power to TANESCO for many years, including Tanwat (2.5 MW), Kiwira Coal Mine (6.0 MW)—which were the first two IPPs---and Kilombero Sugar (2.5 MW). However, they sell only small amounts of excess power, and thus are not treated within the scope of this study. Kiwira's proposed additions will be treated below together with the recently commissioned Mtwara Energy Project.

Table 1: Technical specifications for Tanzania's IPPs

Projects	Size (MW))	Technology /Fuel	Contract type	Contract Years	L Capacity utilization target[8]	Time from tender to operation
IPTL	100	Diesel generator/ HFO	BOO	20	85%	1994[9] -2002
Songas Project	180[10]	OCGT/ Natural gas	BOO	20	91%	1993-2004

Note: BOO, build own operate

Songas, Tanzania's second IPP, commenced operations in July 2004. The 180 MW natural gas-fired plant consists of six open cycle gas turbines, which are run on natural gas sourced from the domestic off-shore Songo Songo gas field (four of the turbines were pre-existing and converted to run on natural gas). The IPP is part of a larger gas project, which included: refurbishment and development of offshore gas wells; installation of a gas processing facility; construction of a 232 km pipeline to Dar es Salaam; conversion of an existing 115 MW power station (Ubungo) from jet fuel to natural gas, consisting of four turbines, as mentioned above; the provision of 65 MW additional capacity at the Ubungo station; the supply of gas for the Twiga cement plant at Wazo Hill; and the development of a larger commercial market for gas.[11] The Songas project benefited from loans from the World Bank's IDA, EIB, and Sida and involved numerous private sector companies and more than 20 contracts. Development of Songas took more than a decade.

[8] Capacity utilization targets are set in the power purchase agreements.

[9] There was no formal tender for IPTL, rather IPTL was a result of a bilateral agreement with Malaysian investors and local Tanzanian investors.

[10] Songas plant size indicated here represents current capacity, which has evolved extensively from project inception; important to note is that the World Bank credit for Songo-Songo Gas Development and Power Generation Project was used towards the first 115 MW at Ubungo, not the addition of 65 MW, which was financed entirely by the private sector.

[11] As of 2007, the project was supplying gas to 16 additional firms, namely: Aluminium Africa, Bora Industries, Karibu Textile, KIOO Limited, Lakhan, Mukwano, Murzah 1, Murzah 2, Murzah 3, Nida Textile, Tanzania Brewery Limited, Tanzania-China Friendship Textile, Tanzania Cigarette Company and Urafiki Textile, and two additional power producers (Aggreko, and Dowans).

Table 2: Financial specifications for Tanzania's IPPs[12]

Projects	Project Cost (US$ million)	Total equity (%)	Total debt (%)	Local equity	Local debt	Int'l private debt	DFI financing
IPTL	$ 127.2	$38.16 (30%)	$89.04 (70%)	US$1 land lease + in kind (PPA & guarantee, 30%)	-	$89.04	-
Songas Project without expansion (115 MW)[13]	$266	$60 (23%)	$206 (77%)	$4 (TDFL) $4 (in kind by TANESCO & TPDC)[14]	-	-	$206
Songas Project expansion (65 MW)	$50	$50 (100%[15])	-	-	-	-	-

Notes: DFI: Development finance institution

It should be noted at the outset of this Chapter that the majority of the analysis is focused on IPTL and Songas and the years leading up to 2006. Following supply shortages and loadshedding in 2006, there has been a flurry of new generation and private power activity proposed. These include several emergency power plants, the Mtwara Energy Project and units at Kiwira Coal Power Limited. Although as of yet, only limited capacity has actually been brought online. A brief description of these developments is provided immediately below for general reference. New publicly sponsored plants will be discussed in section 3.3.

Emergency power

At the end of 2006, with persistent drought conditions, the GoT engaged two emergency plants (with short-term contracts of approximately one year): a 40 MW generator provided by Aggreko and a second 40 MW generator provided by a subsidiary of Alstom. The Aggreko plant is using gas from the Songo Songo gas field at a price of US$2.17/ Million

[12] A detailed breakdown of finances for both IPTL and Songas is presented in Appendix A.

[13] Songas project costs include refurbishment of gas wells, a new gas processing facility, pipeline construction and fuel conversion of the existing power station (Ubungo), in total amounting to US$266 million, and an additional US$50 million for expansion in terms of two additional turbines (total 65 MW) and related infrastructure. The expansion was financed entirely by equity. A rough estimate for the electricity generation component would be 40 per cent of project costs or US$130 million, based on US$35 million for refurbishment and fuel conversion of existing turbines, US$45 million assumed loans on existing turbines, and US$50 million for expansion. It should be noted, as will be described in detail in the text, that there was considerable evolution in terms of the planned capacity for the plant, from 60 MW to the current 180 MW.

[14] Tanzania Development Finance Company Limited (TDFL); Tanzania Petroleum Development Corporation (TPDC).

[15] TANESCO is currently pursuing refinancing of the Songas expansion for a split of 75:25 debt/equity, which would reduce capacity charges.

British Thermal Unit (MMBtu) (*Tanzania* 2007b:4). In addition to these two emergency plants, agreement was struck with Richmond, a special purpose vehicle formed in 2006 to provide 100MW of emergency power, for two years starting in September 2006 (20MW) followed by the balance (80MW) by February 2007, which was safeguarded by a government guarantee. The first 20MW (of the 100 MW) was brought online in October 2006, fuelled with natural gas supplied by Songo Songo, however, only after the government advanced Richmond funds (as neither the parent company, which it turns out is a publisher, with no prior experience in power supply, nor the subsidiary, operating from a residential address in Houston, had money to lift the generators). Dowans Holdings, based in the UAE, has since bought the plant and taken over the contract. Dowans has also overseen the addition of 60 MW capacity (in August 2007).[16]

Mtwara Energy Project

In May 2007, Artumas Tanzania (Jersey) Limited (ATJL) brought online 12 MW, which is being fed by the Mnazi Bay gas field.[17] Also known as the Mtwara Energy Project (MEP), this project dates to 1994, when Tullow Oil was selected (via a selective tender) to develop the Mzani field. In the decade that followed, however, no developments took place, with Tullow citing poor economics of the project as the main stumbling block. In 2003, the Canadian-based Artumas (which had also been involved in the selective tender of 1994) expressed its interest once again to develop the field and related gas and power infrastructures.[18] Subsequently, a Production Sharing Agreement was signed by ATJL, the GoT and Tanzania Petroleum Development Corporation in May 2004. The firm re-entered an existing, unfinished gas well to drill it to acceptable levels in May-June 2005. In July 2005, the parent company, Artumas Group, sought to raise additional funds by listing its shares on the Oslo Stock Exchange as well as by engaging the Dutch Development Company (FMO) in a 20 per cent equity share in ATJL. Seismic studies, the drilling of two more gas wells, and the purchasing 6 x 2MW gas engines to serve the isolated administrative regions of Mtwara and Lindi (on the southern border of Tanzania and Mozambique) followed.

[16] In February 2008, Prime Minister Edward Lowassa resigned after a Parliamentary committee alleged corruption linked to his office in the Richmond case.

[17] ATJL, which is jointly owned by Artumas Group (80 per cent) and FMO (20 per cent), is the 100 per cent shareholder in four subsidiary companies: Artumas Group and Partners Gas Limited (AG&P Gas), Artumas Group and Partners Power Limited (AG&P Power), Umoja Light, and Artumas Energy Tanzania Limited (AETL). AG&P Gas oversees the development of the Mzani gas field; AG&P Power is responsible for developing the power infrastructure; Umoja Light will run the transmission and distribution component, and AETL provides management services to each of the subsidiaries. For the sake of simplicity, however, ATJL alone is used in the discussion above.

[18] At the time, however, in 1994 Artumas was known as Tonardo Resources.

Previously Mtwara and Lindi were served by TANESCO at US$0.42/kWh using old diesel engines with less than 50 per cent reliability, compromised by (1) fuel supply challenges; (2) shortage of cash; and (3) frequent breakdowns. In July 2006, ATJL signed an interim PPA to act as an IPP and sell power to TANESCO at US$0.1195/kWh for the first year. After a year of operations, TANESCO is expected to lease the distribution infrastructure to ATJL, and ATJL will manage an isolated franchise area for 20 years (with less or no subsidy). Negotiations are still on, thus the project has not yet reached financial closure. Sponsors have, however, indicated that negotiations are due to wrap up in 2007 with financial closure expected by early 2008, at the latest. At this stage, apart from interim measures there is no bankable document or long-term agreement. It should be noted that there has been considerable disagreement about the demand of the Mtwara and Lindi regions, with some reports indicating demand of up to 300 MW and others as little as 9 MW. Project sponsors meanwhile have stated that they have identified approximately 90 MW of incremental industrial load, which will be the focus of its business development efforts in the near-term.

Kiwira Coal Power Limited

Kiwira Coal Power Limited presently supplies excess generation from a 6MW plant to the grid. In 2006, the company expressed interest in feeding a further 200MW to the grid. Fifty MW were expected by December 2006, followed by another 50MW in June 2007, and 100 MW in December 2007, however, the firm has not yet secured the funds to finance the transmission line from Kiwira to Mbeya (a distance of approximately 135 km). Although the firm claims to have sufficient funds to develop the (first) power project, no work has commenced due to the lack of transmission funds.

3. Power sector reform context

3.1 The start of reforms

The initiation of electricity sector reforms in Tanzania was catalysed by a combination of macro-reform priorities, national energy policy, electricity sector conditions, and international donor priorities. In 1992, the government expanded macro-economic reforms started under structural adjustment in the mid-1980s[19] to include sector-focused objectives. Also in 1992, the first National Energy Policy, which included intentions to involve the private sector in development of the energy sector, was enacted. In the same year, facing a drought-induced electricity crisis and extensive load shedding, the government lifted the

[19] Tanzania's World Bank and IMF supported structural adjustment began with the Economic Recovery Programme (ERP) in 1986-1989, following on two earlier national economic programmes.

state utility's monopoly on generation to attract private generation and alleviate shortages, which paved the way for the country's two IPPs, discussed in detail in subsequent sections. The reform imperative was reinforced by changes in World Bank lending policy, as the World Bank made electricity sector reforms a condition for electricity sector lending in 1993 (World Bank 1993).

3.2 Early efforts to commercialize and restructure TANESCO

The driving model of Tanzania's electricity reform was originally aimed at restructuring and unbundling the electricity sector for eventual privatization. TANESCO is a publicly owned and run national electric utility. During the 1970's to mid-1980's the national utility functioned adequately, yet toward the end of the 1980's utility performance deteriorated (Katyega 2004:9). From the early 1990's, the firm recorded poor technical and financial performance, making status quo operation increasingly untenable.

In 1992, the utility was forced to shed 130 MW (Tanzania Electric Supply Company Limited 1992:5) due to lack of generation availability. By 1994, load shedding amounted to 100 MW, still nearly one third of maximum demand in the grid system (World Bank 2001:4). Combined technical and non-technical losses amounted to 20 per cent in 1992 up from 15 per cent a decade earlier. Losses reached a high of 28 per cent in 2001, after briefly improving between 1995 and 1998 to 12-14 per cent (Katyega 2004:11). TANESCO was unable to cover its operation and maintenance costs and debt service repayments from its revenue collection, which fell during the 1990's. In the early 1990's, the average tariff was below costs due to reluctance to increase tariffs during prescribed currency devaluations. However, efforts were made to correct the trend, and the average tariff reached a strong position by the mid-1990's, a situation that continued throughout the decade (Katyega 2004:16).[20] Additionally, TANESCO faced difficulties in enforcing payments for services and arrears. Debt collection days deteriorated from 203 days in 1990 to 413 days in 1999 (Katyega 2004:16). Particularly difficult were collections from public institutions (Marandu 2001:37). With diminished revenues for maintenance, outages and distribution losses increased during the same period (Katyega, Marandu et al. 2000:4; Katyega 2004:16).

Efforts were made to commercialise and improve TANESCO's operations in the 1990's via the support of the World Bank Power VI project and the World Bank's Energy Sector Management Program (ESMAP) Power Loss Reduction Study and Technical Assistance to TANESCO Project (World Bank 2003b). However, despite these efforts (including

[20] See Appendix B for a discussion of TANESCO tariffs.

introduction of prepayment electricity meters, loss reduction measures,[21] and contracting out services), TANESCO remained in a weak financial position by the late 1990's, and utility performance deteriorated to unprecedented levels. It should be noted in this context that Power VI, similar to Kenya's Energy Sector Reform and Power Development project, tied the development of the 180 MW Kihansi Hydropower station to power sector reforms, including plans for restructuring the sector and introducing of private participation into both power and natural gas development.

In 1997, TANESCO was put under the President's Parastatal Sector Reform Commission (PSRC), created in 1992 to oversee the privatization of state-owned enterprises in industry and manufacturing. Formal intentions to restructure the power sector to achieve unbundling and eventual privatization were spelled out in a 1997 letter of intent to the World Bank, including restructuring plans to unbundle TANESCO into two generation companies, one transmission company, and two distribution companies.[22] A 1999 Cabinet decision outlined an electric industry policy and restructuring framework to move ahead on restructuring and unbundling in preparation for privatisation was informed by a study tour through, among other Latin American countries, Argentina, funded by Sida and organized by the World Bank. Among the next steps was engaging the international consulting firm, Mercados Energeticos, to assist with a plan for unbundling, privatization and the introduction of competition.[23]

3.3 The management contract and future reforms

Seeking more dramatic financial turn-around in preparation for privatization, the MEM issued a request for proposals for a management contract for TANESCO in 2001, which was won by the South African company, NETGroup Solutions in 2002.[24] The management contract was financed by Sida and from TANESCO revenues[25]. Oversight included the Board of Directors of TANESCO, the PSRC, World Bank and Sida.

Under NETGroup Solutions and with the support of the GoT, TANESCO doubled revenue collection from US$11 to over 22 million per month between May 2002 and May 2004(Ghanadan and Eberhard 2007). These gains were achieved mainly through enforcing

[21] Improvements in losses in the mid-1990's, referenced above, were a result of an ESMAP Technical Assistance project.

[22] Tanzania's commitment was outlined in a Letter of Sector Development Policy written to the World Bank in advance of the Songo-Songo gas-to-electricity loan. Such letters are common requirements to World Bank lending.

[23] It should be noted that Mercados was founded in 1993 in Buenos Aires, Argentina—a country which established wholesale competition starting in 1992 (Dyner, Arango et al. 2006:604).

[24] Eskom of South Africa was an unsuccessful bidder.

[25] Sida funds were administered through a World Bank trust fund, in part in recognition of the World Bank's lead role in overseeing Tanzania's power sector reforms. Officially, the World Bank had oversight over the contract, however no intervention was exercised, and Sida was most directly involved in supporting and monitoring the contract.

collections and arrears payment, with particular attention focused on the large arrears of public institutions. Enforcement has included high profile service disconnections and collections from the police, the national post offices, and even the entire island of Zanzibar in addition to extensive enforcement drives aimed at private customers.

In 2004, the management contract was extended for two years, through the end of 2006. The extension expanded the mandate of the consultants to include technical turn-around in addition to financial-turn around, specifically including electrification and reliability targets. When the contract ended in 2006, its achievements included significant increases in revenue collections and overall success in implementing a complex form of private sector participation with cooperation of the GoT, contractors, TANESCO and donors.

Yet despite the doubling of revenues, the management contract was unable to catalyse improved technical operations. IPPs, which that came online during the contract, brought with them increased and unexpected generation costs. Shifting hydrological conditions created more reliance on IPPs that originally intended. Tariff revisions put in place during the contract proved insufficient as the actual generation charges were greater than the expectations used to calculate the tariff revisions. It also became politically difficult to pass on the increased generation costs to consumers during an election year with extensive loadshedding and poor technical performance. The revenue surpluses were short lived and utility surpluses were redirected to IPP payments rather than investments that would have improved electrification or reliability. Changing sector costs unravelled expectations and hindered the outcomes intended by the contract (Ghanadan and Eberhard 2007:30-33).

In a few short years, TANESCO went from being optimistic about prospects for financing service investments from utility revenues to crisis conditions where TANESCO urgently needed additional funds and emergency supply to account for increasing generation costs, supply shortfalls, and load shedding. These conditions hindered the performance of the management contract and the ability to make necessary investments in reliability and electrification. The prospect of making up the difference of increasing generation costs via large tariff hikes, raises the question of affordability, namely how high tariffs the economy and society can bear. Residential rates have already tripled in the last three years, and access remains only 10 per cent overall. [26] [27]

[26] One important aspect of restructuring and institutional development has been efforts to develop a Rural Energy Agency and Rural Energy Fund (REA/REF). Legislation was passed to establish the REA/REF in 2005 although as of end-2006 it is still not functional. The REA/REF is intended to complement commercialization efforts and consolidate donor activities, as non-commercial rural electrification will be separated out from TANESCO operations and all donor projects and funding will operate through the REA/REF.

[27] For a more detailed assessment of effect of IPPs on the performance of the electricity management contract, see Ghanadan and Eberhard (2007).

Although initially the MEM was considering several different options for TANESCO at the end of 2006, including an extension of the contract and implementation of the original restructuring plan laid out by the government in 1999, TANESCO ultimately reverted to public control. Privatization no longer appears to be a near-term goal, and as of end-2005, TANESCO was taken off the list of utilities specified for privatization. Management is being decentralized, with the re-introduction of administrative zones and corresponding customer services. TANESCO is currently Tanzanian run.

Following on the financial and technical crisis emerging with the shifting terms of generation and onset of IPPs, the GoT is facilitating a 300 billion Tanzanian shilling loan (equivalent to approximately US$230 million based on May 2007 average exchange rate) to TANESCO as a way of dealing with the extensive utility financial shortfalls created under growing generation costs. The loan consolidates the financial subventions previously managed by the government in relation to IPP capacity payments. These are part of a three year Revenue Recovery Plan for TANESCO to continue commercialisation and goals to improve the quality of service. The mechanism responds to the financial--technical crisis and sector adjustments emerging under the onset of IPPs. The entire loan is being syndicated domestically, with the first tranche of approximately US$100 million made available in 2006. Stanbic Bank of Tanzania is the lead arranger; the Government of Tanzania is providing a government guarantee. Importantly, risk and responsibility falls on the GoT. In contrast to the past several decades, no World Bank involvement has been seen to date, and none is expected.

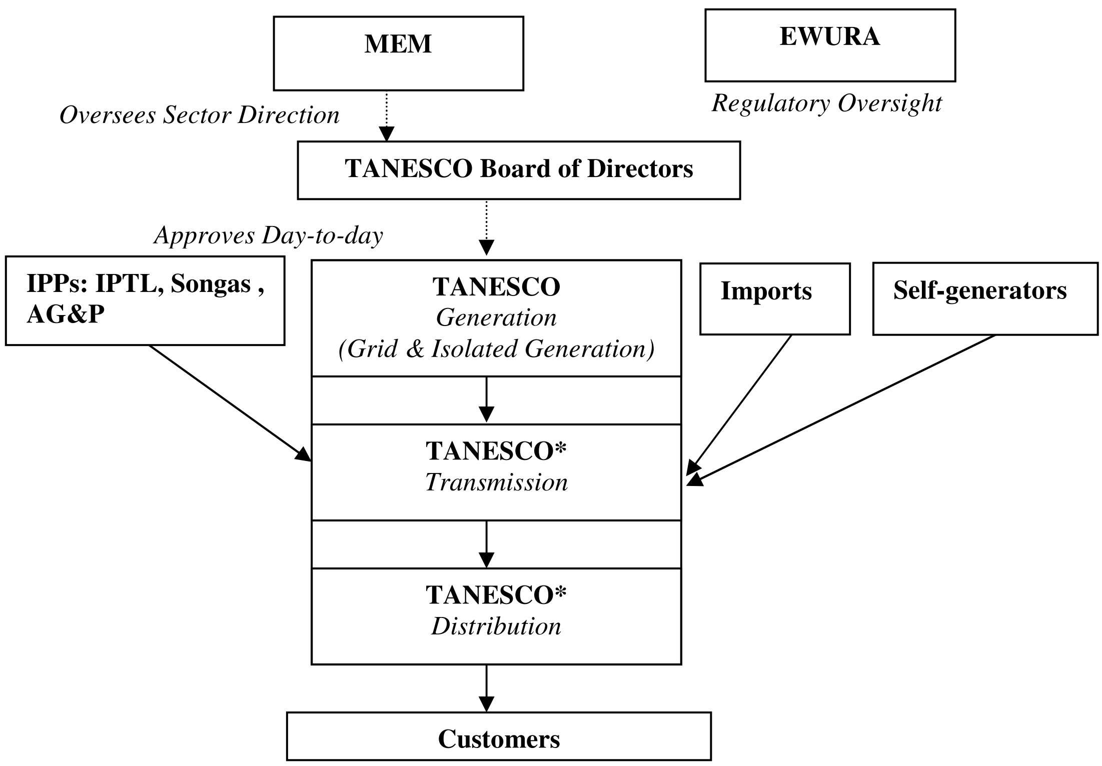
Meanwhile, in terms of new generation, TANESCO plans for new plants, although delivery continues to be a problem. Initially 105 MW of new TANESCO generation was expected at Ubungo (60 MW) and Tegeta (45 MW) in April and December 2006, to be fuelled by gas from Songo Songo. Due to delays in these two projects, however, Aggreko and a subsidiary of Alstom provided 40 MW each, under short-term contracts. Richmond provided 20MW, also under a short-term contract. The two TANESCO plants that were planned are still expected on line, albeit later and in a slightly different form and timeframe. A permanent 100MW Wartsila gas turbine was added to the grid in September which is fuelled by Songo Songo. A further 45MW are expected at Tegeta, with 50 per cent funded by a grant from the FMO's Development Related Export Transactions Programme and 50 per cent via a loan from FMO. This plant is now expected to be commissioned in mid-2008. A further state-led initiative, which has been in the planning stages since the mid-1990s, but for which attention increased in 2006, is the interconnector to link Tanzania with the Southern African Power Pool (SAPP).

3.4 Structure of the sector

After a decade of reform efforts, TANESCO remains a vertically integrated utility but no longer holds a monopoly in generation. The two main IPPs, IPTL and Songas now contribute to generation, in addition to TANESCO's state-owned hydro and small diesel facilities. Small amounts of imports and self-generators also contribute to the ESI. Furthermore, as noted previously ATJL commenced natural gas based power generation for the southern-east franchise of Mtwara and Lindi in March 2007.

MEM oversees sector direction. The TANESCO Board of Directors is appointed by the MEM and approves the day to day operations of TANESCO. Since mid-2006, Tanzania has also seen the emergence of an independent regulator. Although legislation was passed to establish the Energy and Water Utilities Regulatory Authority (EWURA) in 2001, EWURA only became operational in mid-2006, with the following mandate: licensing, tariff regulation and quality of service regulation of the electricity, water, petroleum and natural gas sectors.[28] Although the terms of any future IPPs may be subject to EWURA's review, all the country's existing contracts, including that negotiated with Richmond fall outside its purview, and in its founding documents, the regulator is discouraged from challenging any such agreements (United Republic of Tanzania 2001: 7).

Figure 1: Structure and oversight of Tanzania's electricity supply industry



[28] Debates over the structure of the utility regulatory agencies and their relation to existing oversight bodies and line ministries caused delays in the development of EWURA and the other utility sector regulators.

4. Development of Tanzania's IPPs

4.1 Early gas discovery, drought and gas-to-electricity plan

Gas was discovered in 1974 at Songo Songo.[29] The initial plan was to harness gas for fertilizer production. GoT partnered with Agrico, an American company, in 1981, to form the project company Kilwa Ammonia and Urea Company, KILAMCO (51 per cent GoT, 49 per cent Agrico).

By 1989, with little to no progress made, negotiations collapsed. Failure to close the deal is attributed in part to the poor investment climate at the time, with little support for foreign direct investment.[30] Meanwhile, the idea to use gas for power had long been considered by MEM, but there were insufficient public funds and private investment was not forthcoming. MEM began a more focused evaluation of the gas-to-power option after the Agrico deal fell through. By 1991, it had been determined that gas-based power generation was the next least-cost to hydropower and quicker to develop than other sources, which became a corner stone of the Power System Master Plan of the same year.

Around the same period, in the early 1990s, the GoT was approached by Ocelot (which today operates under the name PanAfrican Energy Tanzania Limited, PAT), a Canadian-based gas company, with a proposal to develop Songo Songo. Among the options that Ocelot and GoT discussed were LNG development, a gas pipeline for export to Mombasa, and gas for domestic use. Two different plans were endorsed by consultants, but no conclusion was reached at this early stage.[31]

On the heels of Ocelot's initial proposals, starting in 1992, the country experienced a major drought. The MEM in turn sought emergency measures to plug its power shortage. In November 1992, Sida, Tanzania's largest bilateral energy donor, provided funds for TANESCO to procure approximately 40 MW of power (two 18 MW ABB GT 10A open cycle turbines, which ran on jet fuel).[32] The turbines were installed at Ubungo. Sida also committed to meeting the operating costs (primarily fuel costs) of the turbines, in the first two years, which amounted to about US$35 million. It was expected that by the end of

[29] Songo Songo 1 (SS1) was drilled and funded by AGIP, which had a Production Sharing Agreement with the GoT; SS2, SS3 and SS4 were drilled by TPDC using Government of India financial and technical assistance, which had been extended to the GoT; the rest of the wells (SS5, SS6, SS7, SS8, SS9) were drilled in the 1980s by TPDC.

[30] One stakeholder characterized the investment climate as follows: Tanzania was emerging from a command economy; firms were (legitimately) concerned with nationalization; the currency was not convertible and firms were not able to repatriate profits.

[31] Export of gas and electricity from Tanzania to Kenya was recommended by Hardy BBT Limited and the Songo Songo Gas Development Project (gas for domestic use) was recommended by National Economic Research Associates, based in the U.S.

[32] The turbines were a conditional grant to the GoT, but a loan to Tanesco and whoever inherited/bought the units. The book value of these two turbines amounted to US$15 million on Transfer Date (August 31, 2004), as indicated in Appendix A.

1993, or shortly thereafter, gas from Songo Songo would be available, i.e. before the grant for fuel was exhausted, the country could convert to domestic gas to feed the two turbines (despite the fact that the gas infrastructure had still not been contracted).

With persistent power shortages, and mounting pressure to procure fuel for the Ubungo plant, in February/March 1993, the MEM invited 16 companies, which had experience in gas and power development, to bid for the Songo Songo gas-to-electricity project. According to stakeholders at the MEM, competition for the project was a pre-requisite of the World Bank, which at the time was active in reform proposals for Tanzania's ESI.[33]

The invitation contained a basic project concept to rehabilitate the existing gas wells (which had been drilled in the 1970s), develop a pipeline to Ubungo, convert and supply two existing (ABB) turbines and add an additional 60 MW (in the form of two additional units), under a Build Own Operate Transfer arrangement.[34] Firms were allowed to form consortia to ensure both upstream and downstream expertise. Among those companies invited were: Enron, British Gas, Amoco and Ocelot.

At the time of the initial invitation, no credit enhancement was provided (i.e. no sovereign guarantees, no escrow accounts) despite a widely perceived poor investment climate and an insolvent utility. Furthermore, firms were given only six months to submit bids with a deadline of August 1993 set by the MEM. It should also be highlighted that the plant size (of 60 MW) was small for international standards.

Due to these limitations (namely, investment climate, time, size), of the 16 invitees, only two submitted bids: OTC, a joint venture between Ocelot and TransCanada Pipelines (a Canadian firm with expertise in power development), and a joint venture of Enron and Andrade Gutierrez.[35] In December 1993, the MEM, TANESCO and TPDC met to review proposals, ultimately recommending the OTC bid to the Minister of Energy. The World Bank was consulted in January/February 1994, and OTC was officially awarded the tender

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[33] World Bank involvement at the time included the Power VI Programme, as referenced in the previous section, a US$200 million loan to help rehabilitate the Tanzania ESI, under which the Kihansi Hydropower station of 180 MW would eventually be developed (initially planned for 1995 but came on line in 2000 only). A key provision in the Power VI Programme was that for any new investments to the power sector of greater than US$5 million the World Bank should be informed—a less stringent condition than that spelled out in the Songas loan agreement which required World Bank approval. The rationale behind this policy, which applies generally to World Bank IDA countries, was to ensure coordination, namely coordination with the World Bank, which was among the largest lenders to the sector.

[34] This project concept would evolve significantly over the decade—from 60 MW to later 150, then scaled back to 115 and eventually to the present 180 MW.

[35] Enron put up a proposal but did not submit it in July 1993 (due to a court injunction against the firm). Only two proposals were received - one from the Joint Venture of Ocelot Energy Inc and TransCanada Pipelines Limited, and the other from Andrade Gutierrez. Since the latter was experienced as a road infrastructure construction company without petroleum exploration skills, during the clarification period, and after Enron was cleared by the court of law, Andrade Gutierrez and Enron formed the joint venture and re-submitted their proposal (in a form of clarification addendum) in November 1993 before the negotiations started.

by February 1994. By July 1994, negotiations commenced in Dar-es-Salaam with the project company Songas, which was composed of Ocelot, holding a 25 per cent equity stake, and TransCanada, which held the balance of the equity.

As negotiations were gaining momentum, the country experienced yet another drought in November 1994. At this time, additional equity partners were under consideration, including TPDC and TANESCO, which would eventually formalize their stakes in the project by October 1995, together with those listed above. In addition, over twenty different contracts were being drafted to satisfy the requirements of the Songo Songo project participants, and financial closure had not yet been reached. Rather than wait the six months or more before the project was finalized, the MEM sought to install additional emergency capacity at Ubungo.

4.2 Persistent power shortages and the emergence of IPTL

It was at this time that GoT began considering, among others, the Independent Power Tanzania Limited (IPTL) project proposal,[36] which would ultimately yield an additional 100 MW. The IPTL project company was formed between a Malaysian firm, Mechmar (70 per cent), and the Tanzanian firm VIP Engineering Limited (30 per cent).

According to numerous stakeholders, the IPTL deal grew out of genuine South-South collaboration, which was being heralded at the time as an alternative to the North-South donor-recipient model of the previous decades. Within this context, Malaysia was seen as a promising partner, a leading "Asian Tiger", whose growth could be replicated in other developing countries. Potential investments were earmarked for the transportation sector, but a first priority was given to electricity. At the time, Mechmar had been contracted by CDC to develop a 2.5 MW unit for the Tanwat wattle factory in Tanzania (see footnote 7). The firm also had experience in developing six other biomass plants outside of its home country. VIP had never worked in the power sector, but had considerable experience as a promoter and negotiator for projects.

On November 21, 1994, IPTL submitted a proposal to the GoT. It should be noted that unlike Songas, there was no formal tender. However, with the persistent power shortages the GoT had been seeking a fast-track solution to increase its non-hydro generation capacity. A meeting was convened on December 15, 1994 to address the proposal, attended by the then Permanent Secretary of Energy and Petroleum Affairs, Commissioner of Energy and Petroleum Affairs, Assistant Commissioner of Energy and Petroleum Affairs, Managing Director of TANESCO and other key representatives from the GoT including

[36] Among the other project proposals cited to address the 1994 power shortage is one by an Irish national, Reginald John Nolan, with investment interests in Tanzania since 1986 including through supplying military equipment to the GoT. Also under consideration since the mid-1990s has been an interconnector to link Tanzania to the SAPP.

the Treasury, State House and Attorney General. At this time, both parties (IPTL and GoT) agreed that IPTL could not meet the fast-track power deadline for mid-1995, but that the firm's proposal might be considered within the context of the country's long-term power plan.

Instead, through a World Bank facility (that existed as part of the Power VI project) the GoT was able to finance two additional turbines of 35 MW each (two GE LM 6000 open cycle turbines, burning jet fuel). Combined with the previous turbines, this now made up a total of approximately 115 MW at Ubungo, which met the immediate shortage, and IPTL was deferred. As with the previous turbines, it was expected that the GE LM 6000 would be converted to burn natural gas at the earliest possible date.[37]

4.3 The AFUDC and increasing Songas engagement

Meanwhile, Songo Songo negotiations continued. Tanzania Development Finance Company Limited (TDFL) (sponsored by EIB), IFC, DEG and CDC all joined the project company by February 1996. Among the key provisions agreed to later in 1996 was the allowance for funds used during construction (AFUDC) and the escrow account.

In the case of Songo Songo, the MEM sought to engage the project sponsor's equity (before debt) for three primary reasons: to commit the project sponsors up to completion (with the consequence that they lose their equity if they quit prematurely); begin work on refurbishment of wells (rather than await financial closure which was expected to take about two years); and finally, debt funds were not available at the time. To entice sponsors to start development, the MEM offered a nominal interest rate of 22 per cent on all equity (denominated in US dollars) disbursed during construction, also known as the AFUDC. Due to the fact that there were no funds to pay sponsors at that time, it was agreed that the AFUDC would be compounded annually until such time that the project started generating revenues. It was expected that revenues would be generated starting at COD, within a one year period. At COD, the AFUDC would be added to the project capital cost (and repaid through the capacity charge), then sponsors would subsequently earn an annual return on equity of 22 per cent (non-compounded). The AFUDC started accumulating in 1996.[38]

[37] While the choice of jet fuel as the preferred fuel for the gas turbines is understandable in the light of plans to covert the turbines to run on natural gas within a short time, it can be argued that it was a risky and costly strategy – particularly as the special quality of jet fuel used was otherwise not commonly available in Tanzania. As a result, the fuel bill was unnecessarily high.

[38] It should be emphasized here that neither the AFUDC, nor any of the other credit enhancements extended to IPTL or Songas, is not uncommon, and (especially) in the case of the AFUDC that the terms agreed upon were based on the assumption that the project would be completed in a timely fashion (i.e. COD was expected by June 1999 which would mean an AFUDC of US$25 million). That assumption proved wrong, and significant interest accrued as it took five more years for the project to reach financial closure and almost a decade before COD, delays that are largely associated with disputes over IPTL.

In addition to the AFUDC, sponsors required an offshore escrow facility to cover 100 per cent of target equity contributions ahead of the Transfer Date (TD, i.e. July 31, 2001), as an exit strategy if nationalization occurred prior to construction completion date. The amount in the escrow account was to be reduced to 50 per cent on the 3rd Anniversary of TD i.e. August 1, 2007 and zero on the 6th Anniversary of TD i.e. October 2010.[39] The escrow was to be raised through a surcharge on fuel.

4.4 IPTL agreement and disagreement

Although Songas was expected to materialize in the near-term, during the same period, negotiations reached completion with IPTL. A PPA was signed between the GoT and IPTL for a 100 MW diesel generator in May 1995, which was expected to be converted to run on natural gas with the completion of the Songo Songo gas-to-electricity project. Standard security arrangements and credit enhancements, as will also be seen in the case of Songas, were sought and obtained. A sovereign guarantee was extended to the project for the full value of the PPA. An escrow account, to be held by the Central Bank of Tanzania, equivalent to between two and four months capacity charges, was also negotiated.[40] These terms differ from those negotiated by Songas, described above, which may be explained by the fact that the MEM never formalized a set of standard IPP terms and conditions and the projects were negotiated by different stakeholders.

Financial closure required another two years, and ultimately involved two Malaysian-based banks (Bank Bumiputra Malaysia Berhad--now Bank Bumiputra Commercial Bank--and SIME Bank) and an informal guarantee by the Malaysian government to the banks that their investment would be secure in Tanzania.

Table 3: IPTL project financing, security arrangements and credit enhancements

Project	Estimated project costs	Equity (30%)	Debt (70%)	Security arrangements and credit enhancements as included in PPA		
				Liquidity facility	Escrow account	Other
IPTL	Monthly capacity charges of US$3.6 million	Return on Equity 22%	Interest rate 8.5%	None (see footnote 40 below)	Equivalent to 2-4 months capacity charge ***(as of yet not established)***	Sovereign guarantee for value of project (PPA)

The circumstances surrounding the IPTL agreement have been widely debated, even criticized, with numerous stakeholders alleging corruption and/or not due process, namely

[39] At the moment, the amount in the Escrow Account is US$2.5 million (with funds having been used to buy down the AFUDC) and will reduce in the same way (as specified above) or if negotiated otherwise.

[40] The IPTL escrow account is in effect a liquidity facility, although it is termed an 'escrow account' by stakeholders. As of May 2007, the escrow account has not been established.

that officials in Tanzania were paid to sign the contract for power, which was not included in the Power System Master Plan and would make Songas redundant. Such allegations are denied by, among others, local partner VIP and IPTL management itself, who argue that the project emerged from a genuine South-South collaboration with Malaysia, the project was identified as a viable solution by GoT starting in December 1994, and the parties agreed (legally) to terms of the PPA.[41]

The impact of the IPTL agreement was not immediate. Negotiations with Songas were ongoing and the project company continued to make equity disbursements to fund the development of the project (with an impact on the AFUDC) until 1997. In this year, several things happened. Firstly, IPTL reached financial closure and started construction, with an Engineering Procurement and Construction Contract (EPC) completed with Stork-Wartsila Diesel B.V. of the Netherlands i.e. the plant began to materialize. Secondly, in the latter part of 1997, Tanzania's hydrological situation reversed due to El Nino. Starting in December, reservoirs began filling and would ultimately overflow (and be able to sustain the country through until 2001). Finally, IPTL plant costs came in at US$150 million (with an additional US$13 million budgeted for fuel conversion to natural gas for a total of US$163 million). As a result, Tanzania found itself overcommitted in terms of capacity; the country needed at the most one plant but certainly not two.[42]

With power now in abundance and financial liabilities mounting, and under pressure from World Bank representatives, TANESCO served a notice of default to IPTL in April 1998 with intentions to terminate the contract. The charge made by the utility was that IPTL substituted medium speed engines for slow speed engines, but did not pass on the capital cost-savings to the utility. Contrary to earlier cost estimates, the government determined that for a similar size/technology plant, it should be paying no more than US$90 million.[43] Disagreement over the substitution[44] and the capacity payment persisted throughout 1998, culminating in a Request for Arbitration on behalf of TANESCO at the World Bank's International Centre for Settlement of Investment Disputes (ICSID), headquartered in Washington D.C. Meanwhile, IPTL filed a petition with the High Court of Tanzania claiming that commercial operations were to commence in August 1998, and as a result,

[41] Apart from the arbitration proceedings, discussed below, in which corruption figured prominently, an investigation was also completed to document the corruption, but charges were never brought by the GoT. Certain stakeholders indicated that the failure to bring charges was due to the fact that "too many were implicated," others that "the investigation itself was flawed" and still others that it was "in the best interest of the country not to pursue".

[42] As will be seen, however, the country's demand increased dramatically over the ensuing years and eventually required the capacity of Songas, IPTL and is presently in need of additional capacity.

[43] In initial discussions with IPTL sponsors on December 15, 1994, spokespeople for the GoT indicated that they would be willing to pay capacity charges of US$27.5 kilowatt (kW)/month, which is considerably higher than the US$90 million investment costs arrived at in 1997.

[44] IPTL contends that it briefed TANESCO on the substitution well in advance and that it was made to enhance maintenance of the plant.

IPTL was owed capacity charges of US$3.6 million for each month since that date. This petition would eventually become part of the ICSID tribunal once it was convened, in June 1999, with both parties agreeing to a cessation of the High Court proceedings.

The tribunal involved several phases. In the first phase, TANESCO attempted to rescind the PPA on the basis of technical issues (namely that medium speed engines were substituted for slow speed engines). In April 2000, in the midst of first phase proceedings, TANESCO additionally requested the Tribunal to hear corruption charges. The request was refused, as no allegations of bribery had been formally pleaded. In May 2000, the tribunal ruled against rescinding the PPA, but stipulated that the capacity payment must be lowered to match actual construction costs. Following on the initial ruling in what may be termed a second phase, TANESCO made additional efforts to rescind the PPA, this time formally raising bribery charges through an Ancillary Claim. Sworn statements were provided by the Permanent Secretary of MEM, Assistant Commissioner for Energy (Petrol & Gas) and Assistant Commissioner for Energy (Electricity). In June, the tribunal ruled that TANESCO could pursue bribery charges, but only within the existing timeframe of the final hearing in one month's time. The tribunal ordered both parties to produce any documents in relation to the charges. The tribunal did not allow wide-ranging interrogations or include a forum to require parties to answer specific questions on bribery allegations.

By July 2000, TANESCO produced some documents to the Tribunal but requested an extension of three months as it had not yet completed its bribery investigation. The tribunal disallowed any such extension, but proposed to TANESCO to withdraw the bribery charges with the option of raising them later in separate ancillary proceedings after completing its investigation, which the utility never pursued. The Tribunal ultimately ruled: i) allegations of bribery had failed based on information presented, ii) capacity charges should be reduced based on actual and reasonable costs incurred, and iii) there had been no breech in the fuel supply, as alleged by TANESCO. The final award, made in May 2001, upheld the PPA signed in 1995, adjusted the capacity charge to US$2.6 million per month, and indicated that conversion to natural gas would be as per the original PPA - with the costs of conversion paid by TANESCO (with a benchmark of US$11.6 million set[45]) and work to be carried out by Wartsila.

4.5 Implications of IPTL dispute on Songas

During the three year dispute between IPTL and TANESCO, Songas would be put on hold out of concern that the utility could not absorb power from two plants and that the ESI was

[45] Current estimates peg this conversion cost at US$20 million.

implicated in corrupt dealings. Three critical developments occurred during this period. First, although no additional work was completed by sponsors, the AFUDC continued to compound at a rate of 22 per cent per annum (which will be discussed in detail below). Secondly, the scope of Songas was scaled down from 151 MW (per 1995 negotiations) to 115 MW in light of the expected IPTL capacity.[46] Thirdly, significant changes occurred to the composition of the project sponsors. Both the IFC and DEG pulled out of Songas shortly after the IPTL dispute became known (with CDC taking over their associated financial obligations of approximately US$12 million).[47] Furthermore, by 1999, TransCanada arranged for the sale of its majority share to AES, citing a strategic decision to consolidate its assets in North America. Two years later, Ocelot (known at that time as PanOcean, later EastCoast Energy and presently PanAfrican Energy Tanzania Limited)[48] would do the same, however, for different reasons, namely consolidating its interests in the Songo Songo gas field exclusively (see details on Production Sharing Agreement between TPDC and PanAfrican Energy Tanzania Limited in Appendix C). Thus, by the time the IPTL arbitration had been concluded and sufficient demand had been ascertained, the AFUDC had increased substantially and the original lead Songas' sponsors had all but transformed (with only CDC, TPDC and TDFL maintaining their minority shares in the project).

It was under AES that the PPA was completed and financing for Songas eventually was finalized in October 2001, nearly a decade after Ocelot had first approached the GoT. As with IPTL (for which financing required an informal guarantee by the Malaysian government), the financing for Songas was atypical in terms of global IPP investments. With no available commercial finance, the GoT obtained an IDA credit together with a loan from the EIB which it then on-lent to Songas at a rate of 7.1 per cent.[49] The total debt

[46] The additional capacity in Songas (previously referred to as the Songas expansion) would be demanded with the 2003 drought.

[47] IFC's pull-out has also been linked to the small scale of the investment, namely that it was difficult for the organization to go to its board for project approval for an investment of US$4 million. DEG's pull-out has been linked further to the size of its own organization: the associated dispute with IPTL exposed DEG to too much risk given its small portfolio of projects.

[48] Ocelot, the initial investor in the Songo Songo gas-to-electricity project, was replaced by its subsidiary company, PanOcean in the Songas project. PanOcean sold its shares in the power project in 2001 to AES to concentrate exclusively in the gas development. In 2004, Pan Ocean spun off its interest in Songo Songo to a separate company: EastCoast Energy, which in April 2007 changed its name to Orca Exploration, but operates under the name PanAfrican Energy Tanzania Limited (PAT). Meanwhile, PanOcean maintains significant interests in oil fields in Gabon. It should be noted that Ocelot did not bid to development the Mtwara Gas-to-Electricity Project. Project inception for Mtwara coincided with the time that Ocelot was negotiating its production sharing agreement for Songo Songo; an additional venture was beyond the appetite for the firm, at the time.

[49] Throughout the 1990s, all export credit agencies were off-cover in Tanzania; no foreign commercial banks were willing to lend as there was no clean track record of commercial loan repayment.

available to the project, as of October 11, 2001, was equivalent to US$260 million (US$200 from IDA and US$60 million from EIB).[50] [51]

Table 4: Songas project financing, security arrangements and credit enhancements[52]

Project	Estimated project costs (million US$)	Equity	Debt	Security arrangements and credit enhancements included in the PPA		
				Liquidity facility[53]	Escrow account	Other
Songas (115 MW)	US$320	(25%) Return on equity 22%	(75%) Interest rate 7.1%	Equivalent to 4 months capacity charge	GoT to match every $ spent by project company	AFUDC
Songas Project expansion (65 MW)	$50	100%		Equivalent to 4 months capacity charge	No new escrow (existing escrow used in part to buy down AFUDC)	None

With approximately four years as lead equity shareholder and with work well underway on the refurbishment of the Songas turbines, AES began to negotiate the sale of its shares. AES's exit from the project was a product of the global downturn in the private power sector and foreign direct investment in general, caused by the Asian and subsequent Latin American financial crisis, after-shocks of 9/11 and the Enron scandal—to which AES was closely associated by analysts by the mere fact that it was an American power company. AES also lost significant amounts of money on its investments in imploding markets in South America. With a plummeting stock price, AES was pressured to sell assets, among them Songas, by both bankers and shareholders.

Globeleq, which as previously noted, was spun off of CDC in 2002 (as the holder of CDC's portfolio of power sector assets), picked up the majority of AES's shares to represent the new lead shareholder in Songas, with the balance going to FMO.[54] Thus by

[50] As per Table 2, however, only US$206 million in DFI funding was ultimately used, only half (US$108 million) of which came from the IDA credit "Songo Songo Gas Development and Power Generation Project" (World Bank Credit 3569-TA). The remaining debt was sourced from EIB, old loans and previous credits.

[51] The reason why concessionary loans were not passed on in entirety to Songas and subsequently to TANESCO to reduce costs further was that the Songo Songo gas-to-electricity project was part of a plan to gradually commercialize TANESCO. Thus, while loan rates were increased from 0.75 per cent to 7.1 per cent, they were still significantly below commercial bank loan rates in the mid-teens.

[52] Table 4 contrasts with Table 2 as it depicts estimated project costs, and the previous table highlighted actual project costs. The Songas project came in under budget, although if we consider the AFUDC, as discussed in detail later, total costs were actually greater not less.

[53] Like the declining escrow account for Songas mentioned earlier, the liquidity facility is fully funded to four times non-subordinated financial obligations (equivalent to 4 x US$2.7 million) for the first three years of operations and reduced to 2 x US$2.7 million throughout 20 years of operations, being cover against TANESCO non-payments or partial payments.

[54] After the AES sale, equity shares and associated financial commitments (expressed in US$ million) in Songas were as follows: Globeleq: US$33.8 (56%); FMO: US$14.6 (24%); TDFL: US$4 (7%); CDC: US$3.6 (6%); TPDC: US$3 (5%) and TANESCO: US$1 (2%). This does not reflect the

April 2003, still one year before COD, the project had seen three different lead shareholders. It was during this sale that the GoT negotiated to buy down the AFUDC, which, according to certain stakeholders, AES had resisted. Initially, as previously indicated, the AFUDC was to be wrapped into the capacity charge, however, by April 2003 the amount had ballooned to US$103 million and would have meant a monthly capacity charge of more than US$6 million, equivalent to almost 30 per cent of TANESCO's revenues. The buy-down was financed by: the Songas Escrow facility (40 per cent) which by 2003 totalled about US$50 million, Ministry of Finance (50 per cent) and TANESCO (10 per cent). Globeleq did not require an escrow facility as a condition of its purchase, and the facility has not been replenished post AFUDC buy-down.

With financial closure completed, the AFUDC out of the way and a new shareholder at the helm, Songas was nearly set for operation. The only piece left was the plant expansion of 65 MW, which although foreseen in the original PPA, was postponed until 2005 due to lack of demand. The expansion was 100 per cent financed by Globeleq (although presently efforts are being made to refinance). The following section addresses operations and associated costs of each plant.

5 Analysis of IPP operations and costs

Although Tanzania's IPPs were considerably delayed, since coming on line starting in 2002, the plants have brought about a transformation of the country's ESI—from nearly 80 per cent hydro dependent to thermal plants making up more than 50 per cent of generation during 2005 and 2006. By 2007, with the return of normal hydrological conditions, reliance on IPPs dropped to 20 per cent of total generation. Songas has been running at about 50 per cent capacity, with limited amounts presently contributed by the emergency plants (Aggreko, Alstom, Richmond/Dowans) as well as about 4MW from AG&P. IPTL is, according to stakeholders, virtually shut down due to the difference in fuel costs. With the two of the three emergency plants running on Songo Songo gas at US$2.17/MMBtu and with IPTL's conversion to natural gas outstanding and therefore running still on HFO at US$8/MMBtu, there is little argument about who to dispatch first. It should, however, be noted, as mentioned at the outset, that this and subsequent analyses focus primarily on the period up to 2007 and therefore almost exclusively on IPTL and Songas.

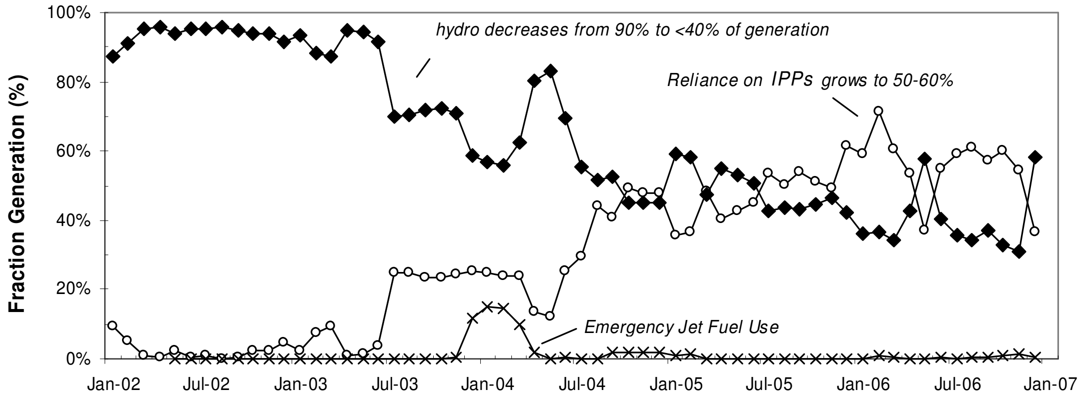
5.1 Generation and capacity utilization

During a period of drought, starting in 2003, the country turned extensively to power from IPTL. Subsequently, Songas was integrated into the ESI, albeit later than initially

additional US$50 million that Globeleq committed for the expansion, which as noted in footnote 15, TANESCO and Songas are presently working to refinancing.

expected, for drought-relief. As noted in the introduction, the thermal power from IPPs helped the country to avoid serious load shedding between 2002 and the end of 2005,[55] which has saved it around US$1.00/kWh of outage averted (or about 5-10 times the cost of generating electricity) (ESMAP, 1998).[56]

Figure 2: Composition of electricity generation, January 2002- January 2007



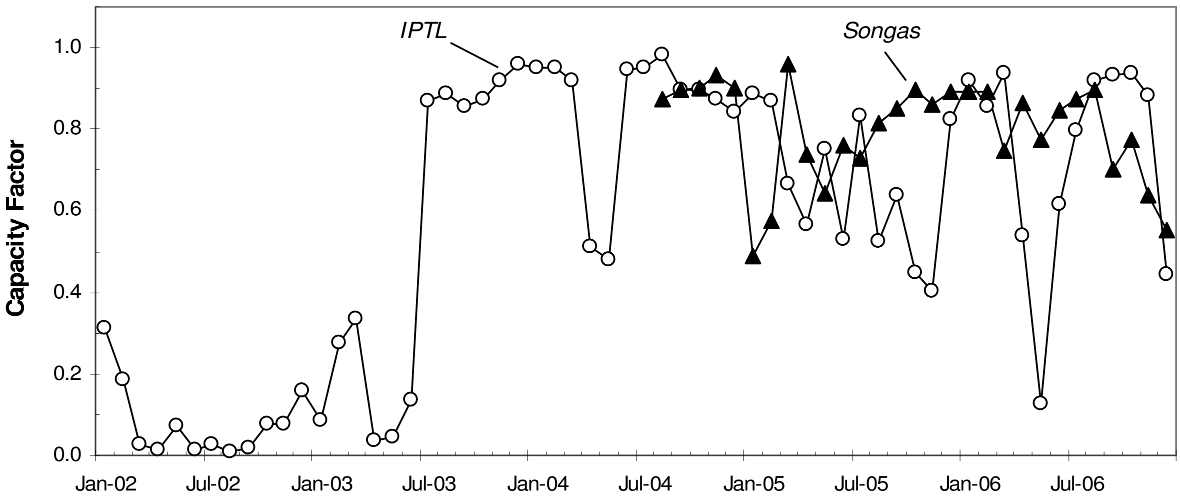
2002: Hydro >90% IPPs 0-10%	Jan 2002: IPTL online Hydro >90% IPPs 0-10%	July 2003: Hydro shortfalls Hydro 75% IPPs 25%	Dec 03 - April 04: Acute hydro shortfalls, Emergency generation to avoid loadshedding Hydro 60%, IPPs 25%,	July 2004: Songas online Hydro 45-60% IPPs 40-55%	Oct-Dec 2005: Transformer breakdow ns, pow er rationing during repairs	Dec 05 - Dec06: Acute hydro shortfalls, loadshedding 12-16 hours/day during 2006 Hydro 40%, IPPs 60%

Source: Calculated by authors from unpublished TANESCO data, 2006.

With increasing pressures due to drought combined with growing demand, the IPP plants were run at near capacity, between 2003 and 2006, contrary to initial concerns about the country's ability to absorb the power.

Figure 3: Capacity factors for IPP generation, January 2002-December 2006[57]

[55] See footnote 1 for a discussion of load shedding due to generation constraints commencing in 2006.
[56] A study by ESMAP (ESMAP 1998) estimates US$1.00 per kilowatt hour as the cost of outages in Tanzania, which is derived from earlier studies showing: the cost of unannounced outages to industrial customers at US$ 2.25/kWh, the cost of outages to other customers at US$ 0.30-$1.00/kWh, and the cost of diesel back-up generation at $0.12-0.33/kWh (ESMAP estimate). It can be noted that the latter estimate has increased considerably over the past few years due to the strong increase in international crude oil and refined products prices.
[57] IPP monthly average capacity factors are calculated from name plate capacity and monthly electricity generation, based on 100 MW capacity for IPTL and incremental increases in capacity with development of Songas: 78 MW (Aug-Sept, 2005), 115 MW (Oct 1, 2004-March 9, 2005), 151 MW (March 10, 2005-June 7, 2005), and 190 MW (beginning June 8, 2005). In the case of Songas 190 MW represents the base maximum capacity, according to sponsors, with the base dependable capacity



Source: Calculated by authors from unpublished TANESCO data, 2006.

Several points are noteworthy in this context. Firstly, delivery of Songo Songo gas was delayed, which, due to an acute power shortage necessitated emergency generation, namely running existing Ubungo turbines on imported jet fuel as well as additional usage of IPTL. Secondly, Songas was not at full availability its first year of operation, which also necessitated additional use of IPTL.

Explanations for Songas' delays and subsequent shortfall in capacity have been attributed to failure of a sub-contractor working on the gas infrastructure to deliver on time, expansion work and technical failure of existing turbines. The plant was offline in January 2005 to make connection for the expansion project. Availability suffered again in May-June 2005 due to failure of turbine III. Although Songas was required to pay penalties for these missteps, according to sources within TANESCO and Songas, penalties do not match the additional costs incurred by the utility during the period, which amounted to US$43 million and was financed through an emergency World Bank loan.[58]

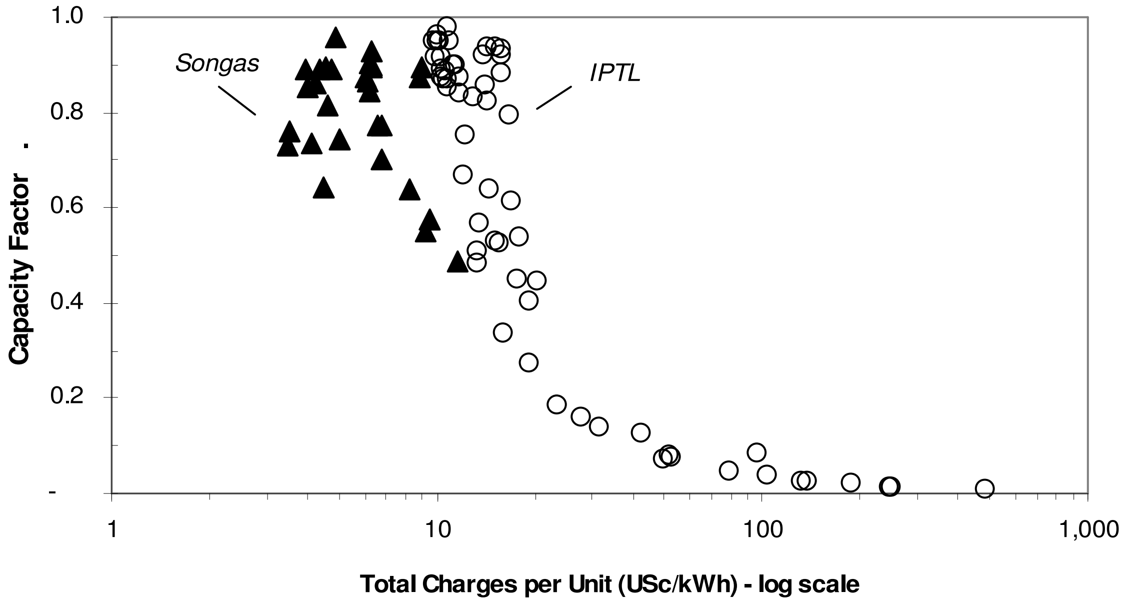
Figure 4 highlights the extent to which the capacity factor alters the per kilowatt hour charge of each of the plants. For instance at a capacity factor of 1 per cent, at which IPTL was run initially, the country saw charges of US$4.80/kWh. Approaching nearly 100 per cent capacity use, IPTL charges fall to US$0.097 per kWh. At full capacity, however,

at 178 MW (Songas per com 2007). In all other instances, throughout this paper, 180 MW is used as the capacity figure for Songas.

[58] Further outages in 2006 were caused by what has been described as technical fatigue due to the fact that the open cycle plant was base-loaded for such an extended period. Songas paid for repairs, and TANESCO did not bear any direct cost other than of course lost revenue due to the fact that the utility had no reserve margin. As a result of the outage, during 2006, Songas' availability dropped to 89.4 per cent, slightly lower than the target of 91.3 per cent, specified in the PPA. The plant, as of 2007, has, however, maintained an average of 91.8 per cent.

IPTL charges are still nearly double those of Songas, despite the fact that the Songas capacity charge is comprehensive of the gas infrastructure. However, Songas costs does not include the AFUDC buydown; and overall project costs are compared in Section 5.4

Figure 4: IPP Total Charges paid by TANESCO per Unit at Different Levels of Plant Use, Based on Monthly Data, Jan 2002 - Dec 2006[59]



Source: Calculated by authors from unpublished TANESCO data, 2006.

5.2 Fuel bills, deals and conversion

While the capacity factor goes a long way in explaining the different prices at the end of the spectrum, especially for IPTL, there is a critical difference variable monthly energy charges in per kWh charges (and total monthly charges) that is explained by the difference in fuel on which IPTL and Songas are operating. Songas uses domestic natural gas, whereas IPTL relies on imported diesel fuel. The gas price for Songas for turbines I-V and for the Twiga cement plant, which was developed as part of the Songo Songo gas-to-electricity project, is set at US$0.55/ MMBtu, indexed to the USA CPI over the course of the 20 year PPA. The special price of US$0.55 only pertains to the ‘protected gas’ that has been earmarked for Ubungo turbines I-V and the cement factory.[60] All additional gas that is sold from Songo Songo is priced at a maximum of 75 per cent the buyer’s liquid fuel

[59] Total charges per unit include energy and capacity charges normalized to generation, and represent monthly averages. IPTL data points include Jan 2002-December 2006 (n=58 months); Songas data points include July 2004-December 2006 (n=28 months). Unit charges are VAT exclusive.

[60] The reason why Ubungo turbine VI was not included in the original gas deal is due to the fact that it was not part of the original project concept. Gas is presently (as of May 2007) being sold at US$2.17 MMBtu High Heat Value (HHV), the same price for which gas is being sold to Aggreko and Richmond/Dowans.

equivalent. Presently TANESCO is negotiating long-term gas contracts at between approximately US$2.00 and US$2.40 per Gigajoule GJ (1 GJ = .95 MMBtu).[61]

Table 5: Songo Songo gas reserves pricing and usage

Characterization	Price	Notes
I. Protected Gas	US$0.55/MMBtu	Allocated for Songas (turbines I-V = 150 MW) plus cement factory for 20 year PPA
II. Additional Gas	Maximum 75% of liquid fuel equivalent	All non-protected gas, includes both reserve gas described below and gas currently used for Ubungo VI (below), IPTL fuel would come from 'additional gas'
i) Reserve Gas	Maximum 75% of liquid fuel equivalent	100 Bcf of gas set aside for government to determine use within 5 years of transfer date (July 2004)

Note: Bcf: billion cubic feet

Although gas sales with third parties are developing (from seven companies in 2006 to 16 as of 2007), until recently they were a fraction of total production; Songas and therefore TANESCO (since fuel is a pass-through) was the primary taker, and therefore in essence the market maker. Songas' fuel price was conceived of as part of the initial project concept to offset the capacity charges so that the utility would not shoulder the full weight of developing the country's gas infrastructure.

While not benefiting from special 'protected gas', IPTL was, from project inception, slated to be converted to run on natural gas and source its fuel from the 'additional gas' reserves of Songo Songo. The project was therefore to benefit from an estimated minimum fuel cost savings of 25 per cent (given the additional gas price set at a maximum of 75 per cent the liquid fuel equivalent). This plan was reconfirmed in the IPTL arbitration when US$11.6 million was tagged as an estimate to be paid by TANESCO for converting IPTL.[62] Although the savings is not equivalent to Songas, it would amount to a reduction of approximately US$1 million per month (given a current average monthly fuel charge of about US$3.6 million).[63]

Songo Songo gas was available starting July 2004. However, IPTL has still not been converted. Conversion has repeated been delayed. In 2005, stakeholders attributed conversion delays to a host of factors: probability and availability of fuel reserves; technological conversion challenges; securing financing; resistance from lenders; fuel

[61] Benchmarking these prices represents a particular challenge since there were few options for the gas as it was virtually a stranded asset. A comparison with the Henry Hub natural gas spot prices of US$14.80/MMBtu (December 2005) provides little actual value. A potentially more accurate comparison may be the net-back value of exporting gas to Kenya (Mombassa), which has been approximated at more than US$3.00/MMBtu.

[62] As noted in footnote 45 current cost estimates for conversion are closer to US$20 million.

[63] Stakeholders in the MEM indicate that fuel savings will be even greater for IPTL, at 60 per cent (not 75 per cent) of present costs, based on HFO prices. In addition, further reductions in cost may result from the increase in the efficiency of the plant running on natural gas.

pricing formula; and debt and equity renegotiation/disputes (which are discussed in detail in Appendix D). Of these six factors contributing to delays, among the most common cited by stakeholders was that concerning conversion of the technology itself. The engines needed to be converted, but Wartsila SWD 18 V 38 diesel engines had never run on natural gas. Thus Wartsila, which is also the operator of IPTL, first needed to conduct a series of tests. Although according to one stakeholder close to the project, "this is not rocket science", a test-bench must be booked and time allotted to carry out the work. As of 2007, conversion delays are primarily attributed to agreement not yet being reached between owners and debt-holders (which will be discussed in detail in section 5.3). Furthermore, new potential challenges have arisen with regard to the Songo Songo gas processing plant.
The capacity of the gas processing plant is about 105 million standard cubic feet per day (MMcfd), and as of May 2007, the plant was utilized at 65 per cent, with Songas, Aggreko, Alstom and the 14 other gas customers. With the IPTL conversion (100MW), capacity utilization will be 100 per cent with a buffer of approximately 20mmscfd. Thus, when/if rainfall subsides, there will be insufficient capacity to feed the 100 MW Wartsila plant at Ubungo (expected in September 2007) and the Tegeta plant (expected in July 2008). Although the procurement process has started to increase capacity, here also delays have been encountered, which could impede gas delivery. Thus, presently under discussion is a plan to further delay the IPTL conversion to ensure that Wartsila is supplied. Conversion might therefore happen as late as 2009.

5.3 Monthly charges to TANESCO

Actual monthly charges to TANESCO for operating the two IPPs (inclusive of both energy and capacity payments) during 2005 amounted to an average of US$13 million per month, or well over 50 per cent of TANESCO's monthly revenue. For 2006, this figure skyrocketed to a staggering 96 per cent of TANESCO's monthly revenues. Table 6 shows that the most significant monthly charges are for Songas' capacity charges and for IPTL's variable energy charges.
A number of factors are responsible for changes in 2006. Songas turbines V and VI came online in mid-February and end-May 2005 and increased capacity charges by US$ 2.3 million in 2006. Growing oil prices (and increasing HFO costs) increased the IPTL energy charges passed on to the utility by US$ 1.2 million per month. Exchange rate fluctuations reduced the USD equivalent value of utility revenues by US$ 2.1 million (and increased VAT charges paid by the utility for IPP generation by US$1.0 million). As a result of these factors, utility costs increased US$4.5 million, revenues decreased US$ 0.8 million. These conditions created a gap of TSh 6.6 billion per month (US$ 5.3 million) in less than one year and a financial crisis for the utility, even despite its growing generation.

Table 6: IPP monthly charges to TANESCO and Overall Electricity generation[64]

IPTL	**2005**	**2006**	**Whole Period**	**Whole Period**
	Average	Average	Average	Range
Capacity Charge	2.6	2.7	2.5	2.3 - 2.8
Energy Charge	3.5	4.7	3.0	0.03 – 6.4
VAT (20%)	1.5	1.8	1.4	0.05 – 2.3
Total IPTL Charges (million US$/mo)	$7.6	9.3	$6.9	$2.9 – 11.4
Total IPTL Generation (GWh/mo)	48.1	53.4	41.6	0.5 - 73
Songas	**2005**	**2006**	**Whole Period**	**Whole Period**
	Average	Average	Average	Range
Capacity Charge	3.3	5.6	4.3	2.2 – 6.2
Energy Charge	1.2	1.3	1.6	0.2 – 2.0
VAT (20%)	0.8	1.4	1.1	1.0 - 1.6
Total Songas Charges (million US$/mo)	$5.4	8.2	$6.6	$3.9 – 9.6
Total Songas Generation (GWh/mo)	95.8	111	97.1	19 – 130
IPP Charges (million US$/mo)	**$13.0**	**$17.5**	**10.0**	**$2.3-20.8**
TANESCO Revenue (million US$/mo)	**$19.1**	**$18.3**	**$16.6**	**$12.2 - 22.0**
IPP Charges vs. TANESCO Revenue (%)	**68%**	**96%**	**62%**	**16-107%**
IPP Generation (GWh/mo)	**144**	**165**	**91**	**0.54 – 193**
Total Generation (GWh/mo)	**278**	**298**	**278**	**233 – 325**
IPP vs. Total Generation (%)	**31%**	**55%**	**31%**	**0.2-71%**

Source: Calculated by authors from unpublished TANESCO data, 2006.
Note: GWh: gigawatt hours; mo: month

For IPTL, capacity charges were negotiated on a straight-line basis for the 20 year duration of the PPA, which means provided there are no changes to the project ownership or debt, the utility will pay US$2.6 million monthly, adjusted for inflation, going forward. IPTL's variable energy charges are expected to reduce by a minimum of 25 per cent when the plant is converted to run on natural gas[65].

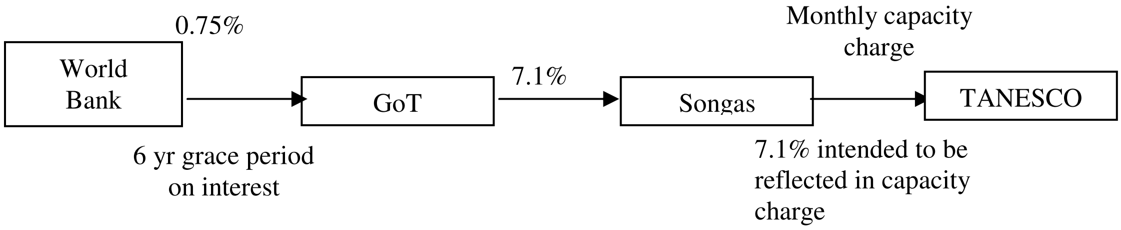
For Songas, the situation is different, as the capacity charge declines on a straight-line basis to zero over the life of the project, with the loan repaid by year 18. Notably Songas' capacity charges includes the entire gas infrastructure and are higher than what would be result from construction cost of generation at Ubungo alone. Also, TANESCO has not paid the subordinated debt portion of the Songas capacity charge exercising the 'grace

[64] Average values for the whole period for each respective IPP include: IPTL Jan 02-Dec 06, for Songas July 04- Dec 06. Also note that total IPP charges and total IPP generation during whole period do not equal the sum of individual IPTL and Songas values. Total charges span the whole period from 2002 to Dec 2006. However, Songas only came one line in July 2004. Thus for many months only IPTL was running, and average values and ranges do not correspond.

[65] Although capacity factors matter in terms of variable monthly energy charges, capacity charges are fixed monthly charges to the utility, which finance the capital cost of the project.

period' on the Songas loan from mid-2005 to mid-2006, and the liquidity facility is presently at zero.[66] If Songas were paying the full subordinated debt portion, Songas capacity charge of would have averaged US$ 5.2 million in 2005 and US$ 5.8 million in 2006 (instead of US$ 3.3 million and US$ 5.6 million per month actually paid, see Table 6). Full charges would reflect the 7.1 per cent interest rate and amount to approximately US$5.8 million per month (plus US$1 million VAT), with US$4.2 million for turbines I through IV and an additional US$1.6 million for turbines V and VI.

Figure 5: Songas financial arrangement



Source: authors compilation based on stakeholder input

The current non-payment of the subordinated debt was provided for in the subsidiary Loan Agreement dated October 11, 2001. Due to the fact that GoT borrowed funds from IDA and on-lent to Songas (at a premium), if TANESCO fails to pay Songas the amount equivalent to the principle and interest, Songas is relieved and forgiven up to that amount, while TANESCO is treated as a borrower at more stringent interest but relieved until it is able to pay. Since TANESCO is wholly owned by the state, it is up to TANESCO to make a case either to pay or swap with other obligations of the State. Initially it was expected that the existing arrangement would continue until such time when the government declares the utility bankrupt or TANESCO becomes liquid and pays, however, presently, there is a strong likelihood that the debt may be forgiven by the GoT as part of TANESCO's Revenue Recovery Plan. Regardless of the final resolution, this arrangement has helped the utility to reduce its present financial liabilities for Songas to almost half.

Although there has yet to be impact on either plant operations or charges, equally noteworthy in this context are the idiosyncrasies and conflicts related to IPTL's debt structure, which have evolved after COD. In February 2002, only one month after IPTL commenced commercial operations, local partner VIP petitioned the High Court of Tanzania to wind up the project company. Reasons provided by VIP were: oppression by the majority shareholder (namely that Mechmar refused to involve the VIP nominee director of IPTL in corporate decisions); fraud by Mechmar in inflating the IPTL capital

[66] The utility is still paying the EIB portion of its subordinated debt, i.e. it only applies to the World Bank portion of the debt.

cost; and failure by Mechmar to pay its equity contribution (i.e. the project was 100 per cent debt financed). IPTL management has denied all claims. [67] There has been no resolution of this conflict.

In the meantime, however, IPTL's debt, which was non-performing, was first purchased by Danaharta, a Malaysian entity that bought up many non-performing loans after the East Asian financial crisis, and then resold to Standard Chartered for US$74 million in November 2005. VIP has subsequently contested the sale to Standard Chartered on the basis that the very loans that were resold are under dispute. Meanwhile, since the sale to Standard Chartered, the GoT has been in negotiations to buy IPTL's debt, with the Ministry of Energy indicating that such a purchase should be finalized by end-2007.[68] Furthermore, it is expected that subsequent to the debt purchase, the government will also buy out the firm's equity. Should any sale be finalized with GoT, the project may see a significant reduction (if not complete elimination) in capacity charges (see Appendix A for a breakdown of project costs). Finally, an important point to reiterate is that conversion is expected after the gas processing plant increases capacity and the debt and equity buy-out is finalized. There is a remote chance that if conversion is delayed, with new TANESCO thermal due online (namely the 100 MW Wartsila plant at Ubungo), IPTL may actually be mothballed until such time that it may run on natural gas.

5.4 Benchmarking costs

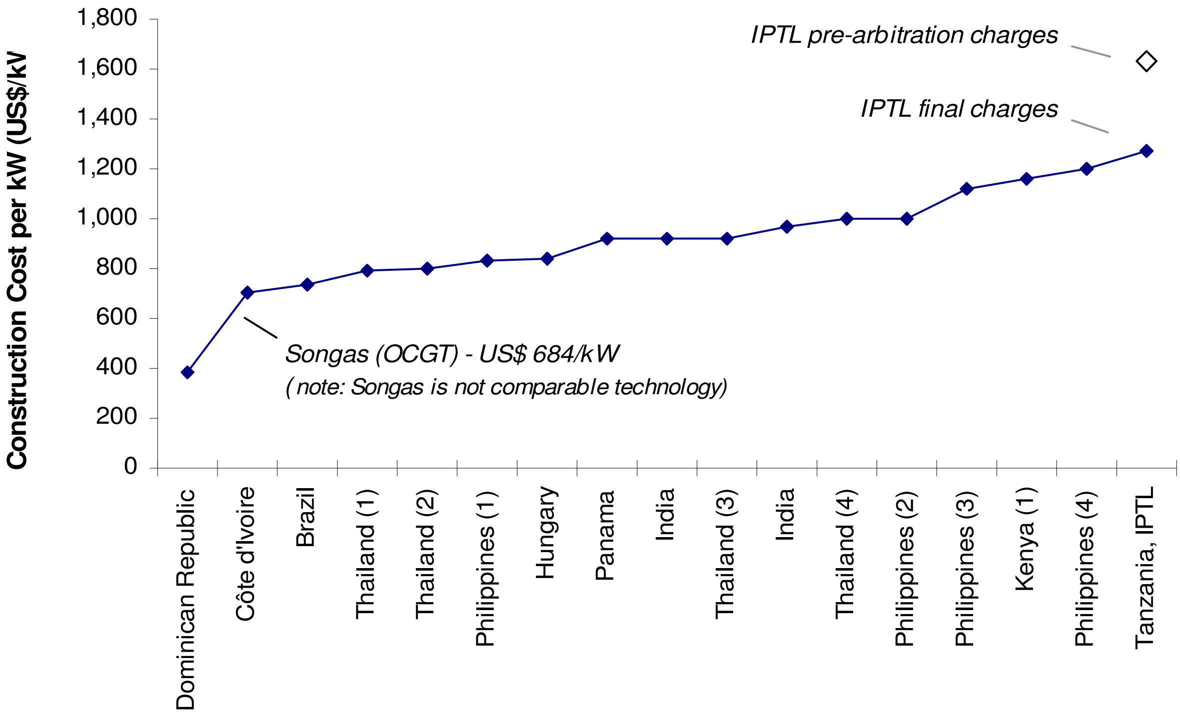
To benchmark IPP costs it is useful to examine overall construction and generation costs. For IPTL, based on construction costs per kilowatt, at both its pre-arbitration costs of US$1,635 and its post-arbitration costs of US$1,272, IPTL appears to have the highest such costs within a sample of similar size/technology IPPs in developing countries. Kenya's Iberafrica plant is, however, in close proximity, indicating that costs may be generally inflated for the East Africa region. (see Appendix E for a full listing of the comparable small diesel IPPs represented in the Figure below)

Figure 6: IPTL construction costs versus small diesel IPPs in developing countries[69]

[67] With regard to the equity contribution, IPTL maintains that equity has been contributed by Mechmar; the firm's financial situation has changed drastically, however, since the arbitration, during which period, IPTL incurred significant debt.

[68] The sale price to GoT has been estimated at between US$70 and 80 million, although VIP asserts that, according to the amortization schedule in the arbitration award, the value of the debt should be no more than US$40 million.

[69] Note: Small Diesel in Figure 6 includes plants in developing countries with capacity less than 110 MW.



Source: Calculated by authors based on data from World Bank (2004) and Gratwick and Eberhard (2005)

Although Songas employs a different technology, namely OCGT,[70] isolating project costs related only to the plant (as detailed in footnote 13), the per kilowatt construction costs are approximately US$684 or about half those of IPTL. However, benchmarking Songas costs depends extensively on how one interprets and allocates project costs, including the AFUDC. As described in Section 4, project delays significantly increased Songas construction costs, leading to interest costs of US$ 100 million. The payment of these interest costs were borne by the government and increased the overall costs of this project by nearly 30%. The AFUDC was bought down using public monies and reduced the capacity payments paid by TANESCO by approximately US$ 1.6 million per month (versus without the buy down). Whether or not one includes these interest charges in the costs of power, has a significant impact on how these costs are benchmarked.

Table 7. Breakdown of Songas costs Including Interest Charges

Songas	Project costs (US$ million)	Financing
Initial Project costs - Pipeline construction & turbines 1-4 (115 MW)	**266**	70% debt: 30% equity

[70] Using natural gas as a fuel makes Songas also more efficient from a fuel usage perspective.

Songas expansion - Addition of (turbines 5-6 (65 MW))	**50**	100% equity (Globeleq)
AFUDC Interest Charges	**103**	GoT: Treasury (40%), TANESCO (10%), Escrow (50%)
Fraction of Project costs due to interest on project equity	*33%*	

Source: See Appendix A

Given Songas' lower variable cost (i.e. lower fuel costs of natural gas vs heavy fuel oil), Songas is dispatched before ITPL (following basic merit order dispatch protocol). As a result, Songas is contributing more in terms of total generation. In terms of charges paid by the utility (i.e. not including the AFUDC), IPTL's average total kWh charge has been nearly double that of Songas. An analysis of the kilowatt charge per hour shows IPTL's per KWh charge averages 14 USc/kWh (accounting for both fixed and variable costs). For Songas charges actually paid by TANESCO (not the full costs of the project) average 6.2 USc/kWh. Accounting for full project costs Songas averages 8.2 USc/kWh.

Table 8. IPP Total Charges per Unit over Lifetime of Projects to Date, January 2002 to December 2006[71]

IPTL	**2005**	**2006**	**Whole Period**	**Whole Period**
	Average	Average	Average	Range
Capacity Factor	0.70	0.74	0.65	0.01 - 0.98
Energy Charge per unit (USc/kWh)	7.5	9.2	7.5	3.9 – 54
Total Charge per unit (USc/kWh)	13	15	14	9.7 – 483
Songas	**2005**	**2006**	**Whole Period**	**Whole Period**
	Average	Average	Average	Range
Capacity Factor	0.77	0.79	0.80	0.49 - 0.96
Energy Charge per unit (USc/kWh)	1.3	1.1	1.1	0.4 - 2.0
Total Charge per unit - Actual capacity payments	4.7	6.2	6.2	3.5 – 12
- Cost if including AFUDC	7.9	8.0	8.2	6.5-15.4
(USc/kWh)				

Source: Calculated by authors from unpublished TANESCO data, 2006.

In sum, IPTL costs do appear to be higher both than the international norm and its IPP counterpart, Songas. Although IPTL constituted only 33% of total IPP generation for 2005

71 IPP monthly average capacity factors are calculated from name plate capacity and monthly electricity generation, based on 100 MW capacity for IPTL and incremental increases in capacity with development of Songas: 78 MW (Aug-Sept, 2005), 115 MW (Oct 1, 2004-March 9, 2005), 151 MW (March 10, 2005-June 7, 2005), and 190 MW (beginning June 8, 2005). In the case of Songas 190 MW represents the base maximum capacity, according to sponsors, with the base dependable capacity at 178 MW (Songas per com 2007). For IPTL the whole period includes Jan 02-Dec 06, for Songas July 04-Dec 06. VAT exclusive.

and 32% in 2006, in terms of utility capacity payments, IPTLs cost accounted for close to 60% of the total in 2005 and over 50% in 2006 – thus illustrating the high costs of IPTL power. However Songas costs, while lower that IPTL, are also substantial. Costs of 8 USc/KWh are high given the low costs of fuel and the impacts on public finance overall.[72]. Thus IPTL costs are higher, but Songas are also substantial.

Table 7. IPTL and Songas Shares of Total IPP Generation and Charges[73]

	2005	2006	Whole Period
Total IPP Generation	100%	100%	100%
% IPTL	33%	32%	46%
% Songas	67%	68%	54%
Total IPP Charges	100%	100%	100%
% IPTL	58%	53%	68%
% Songas	42%	47%	32%

Source: Calculated by authors from unpublished TANESCO data, 2006.
Note: IPP charges are based on TANESCO payments and do not include full Songas project costs

6. Balancing outcomes?

The development outcome for Tanzania has been mixed. The country has been able to expand its generation capacity and did not resort to serious load shedding between 2002 and 2005 (see footnote 1). Tanzania also has succeeded in commercializing its natural gas, which has helped reduce the fuel bill for the state utility and numerous other small industries (previously reliant on petroleum imports) as well as alleviate the pressures related to securing quality fuel in a timely manner from abroad. GoT may claim a payback period of less than half the time originally estimated on turbines I-IV of the Songas project (or three years instead of six), due to the increase in JET A-1 fuel prices.[74] Songo Songo gas has also been critical in fuelling emergency plants, Aggreko and Richmond/Dowans.

Despite these developmental gains, power in the case of IPTL is, as has been shown in the previous section, proving to be more expensive than the international norm (even post-

[72] Additional costs related to Songas: 1) the AFUDC was paid down by GoT, Treasury and Tanesco for US$103 to reduce the capacity charge; 2) the subordinated portion of Songas World Bank debt is currently not being paid; 3) the escrow facility of US$50 million (which was used to help pay down the AFUDC is presently only US$2.5 million) but did until 2003 tie up GoT funds; 4) the cost of the original drilling of the wells, which amounted to approximately US$100 million, is as indicated above, treated as a 'sunk cost'. The calculation above includes the AFUDC and subordinated portion of the World Bank loan.

[73] Average values for the whole period includes 2002 through 2006. However, Songas only came online in July 2004, thus the independent use of IPTL between 2002 and June 2004 accounts for Songas' significantly lower generation shares despite being nearly twice the capacity of IPTL.

[74] This is calculated by taking: the total project cost (debt US$206 million + equity US$60 million), divided by the product of 12 months and monthly energy saving (replacing Jet A-1 fuel with natural gas) of aboutUS$3.5 million for UGT1 -UGT4, by the then prices, which means that the payback period is almost 6.33 years. Since Jet A-1 fuel prices doubled in 2005, the payback period is reduced by half to almost three years.

arbitration). Furthermore, the IPTL arbitration was particularly costly to Tanzania, both in terms of direct and indirect costs of arbitration, and eroding credibility of the project in the eyes of many stakeholders. Songas, while less costly than IPTL, did incur significant costs to the country in the form of the AFUDC and the escrow account. The extent to which IPTL and/or IPTL-related events inflated Songas costs (particularly the AFUDC being 75 per cent more expensive than expected) should not be overlooked.

With regard to the investment outcome, it too has been mixed. Parties have secured a ROE of 22 per cent, but there has been significant equity turnover, and Globeleq is the third lead shareholder on the Songas project, after previous ones lost interest due in part to project delays. The present majority shareholder in IPTL, Mechmar, has been trying to sell the asset for several years, and the minority shareholder issued a winding up petition to terminate the company four years ago (which remains pending). TANESCO has been unable to make its full debt payments (to Songas and hence to the GoT), and IPTL's loans were declared non-performing, and then bought by Danaharta, an initiative of the Government of Malaysia, and most recently by Standard Chartered. New IPP capacity, namely ATJL, has been added, without a formal framework. Meanwhile, the emergency power that plugged the 2006 power deficit was financed through state and concessionary funds, as are the new plants expected at Ubungo and Tegeta.

With considerable negative results reported, and outcomes ultimately recorded as mixed, is it appropriate to discuss balance and sustainability? It would appear that such results do not translate into sustainability for IPTL. A resolution may be on the horizon if the government buys the IPTL debt, but such would not represent sustainability with regard to the original project concept and partners. In terms of Songas, although results have been superior to IPTL, according to the firm, as of June 2007, "the investment has the poorest payment and security record of any of our plants in Africa and Asia." Although the firm is presently selling all of its other assets, as previously discussed, it is retaining those in Sub-Saharan Africa due to the fact that the indicative bids have not been favourable. Does this in turn mean that outcomes are rated poorly? This paper would argue that the Songas contract may ultimately be upheld, but it is unlikely that a similar experience will be actively sought again. It may be sustainable for one project, but surely not replicable.

The following sections examine the myriad factors that affected outcomes. Of the different exogenous stresses reviewed to date (civil strife, macroeconomic shock and associated currency devaluation and drought), only one is taken up in the discussion below, and only in the broader context of electricity sector reforms. As seen in Kenya, there has been no evidence for macroeconomic shock; instead, in evidence is creeping devaluation throughout the course of the 1990s, in Tanzania, followed by a relatively stable currency environment in the period since the IPPs have come online. Thus, there has been little to no perceived impact to date, however, with PPAs of 20 year duration, denominated in US dollars, there is always a risk of future impact, which may be exacerbated by the rising price of fuel imports (so long as IPTL relies on HFO).

6.1 The investment climate: risk perceptions

The first initiative to develop the Songo Songo gas field collapsed in the 1980s largely due to the poor investment climate. At the time of the inception of the IPP plans in the early-mid 1990s, little had improved in terms of the investment conditions. It is arguable that conditions had even worsened, with an all time high inflation level of between 30-35 per cent reported in the mid-1990s and no foreign commercial lenders willing to lend to the sector.

While there were several impediments to the initial bid for Songas (size of plant and short bid time), the investment climate features prominently in why more investors did not come to the table. With the risk of expropriation still perceived, investors took little interest in the Songas bid, with only two of the 16 firms invited submitting bids.[75] It should also be noted that the mere fact that there were no previous such investments exacerbated the perception of risk.

Both IPTL and Songas eventually obtained debt at interest rates of less than 10 per cent (below commercial rates, available in the mid-teens), but the debt was not easy to come by, which may also be linked to the poorly perceived investment climate in Tanzania. In the case of IPTL, eventually the Government of Malaysia intervened to convince two Malaysian banks that their loans would be secure, which amounted to an informal guarantee on the part of the Malaysian government.

In the case of the Songo Songo gas-to-electricity project, in a departure from most project-financed IPP deals globally, the GoT obtained concessionary loans, which it then on-lent to the project sponsor. Although less costly than commercial debt (which again was not available to the sector at the time), these loans required substantial time and conditions (with the World Bank mandating that any future power investments in excess of US$5 million first receive World Bank approval--a more stringent condition than that laid out in the Power VI plan, which only required notification not approval, see footnote 33).

Although both IPTL and Songas were able to obtain debt at interest rates of less than 10 per cent, the two project companies required a ROE of 22 per cent, a further indication of the riskiness of the investments and the general climate. According to sponsors, this was comparable to the ROE of projects with similar risk profiles within the region and adequately reflected the risk inherent in the Tanzanian ESI, namely that TANESCO, the

[75] Insofar as there was no organized competitive bid for IPTL, it is difficult to evaluate the direct impact of the investment climate on the bid.

off-taker, had no experience in paying IPP capacity charges and was financially feeble at the time.

It is arguable, however, that much of the risk was mitigated by additional facilities negotiated by the projects, which have been used extensively for infrastructure projects globally. Both projects negotiated liquidity-type facilities, (although IPTL's is referred to as an escrow account and has yet to materialize). In addition, IPTL obtained a sovereign guarantee equivalent to the value of the PPA. Songas received no outright guarantee, but it did convince the GoT to establish an escrow facility and provide a rate of 22 per cent on AFUDC compounding annually.

Public stakeholders contend that fear of deals unravelling, in such an investment climate, did motivate these extra protections. This has, however, been countered by private stakeholders who insist on both the standard nature of such additional protections as well as the now accepted position of the private sector playing a critical role in providing infrastructure, i.e. no longer accepted practice that assets should default to state hands. What does the evidence say? Have bargains obsolesced? Have security measures reduced and/or eliminated the obsolescence? For Tanzania at the end of a decade of private power, one of the IPPs may be returning in part to state control and the next long-term power is being provided by the state, with concessionary funding. These developments do not, however, represent any outright or creeping expropriation. Instead, they seem to point to an attempt at redressing the perceived imbalance in development and investment outcomes. Thus, while the fear of deals coming unstuck may have played a role in motivating behaviours, the associated protections that followed have not been determinative. Instead, it is the apparent imbalance that has been instrumental in bringing about changes to the present and future deals.

This is still not the whole story. More remains to be said about how such an imbalance came about. Although the investment climate contributed significantly to outcomes, one cannot attribute to it all the project ills or benefits. There was after all no independent regulator to review PPA contracts. Furthermore, other factors such as actual project plans and execution have contributed significantly to outcomes.

6.2 The electricity sector: drought, doubt and reform

The management of the electricity sector, which was widely affected by drought and the intervention of other ministries, played an equally if not more important role in determining project outcomes than those previously discussed. The primary issue of relevance in this context is the planning and execution of the Power System Master Plan, which initially included specifications for Songas, but not for IPTL.

Throughout the early and mid-1990s, Tanzania experienced severe drought conditions and power shortages. It was in this emergency context that four turbines were installed at Ubungo prior to completion of the Songas deal. It was also in this context that IPTL first bid to build fast track power in Tanzania. According to several stakeholders in the MEM, they were roughly operating within the Master Plan but on a six month timeframe with the intent of solving the drought induced shortages as expeditiously as possible. But six months came and went with Songas, and sponsors and other key stakeholders did not see the project materializing.

With deadlines passing and power cuts persisting, it is alleged that other ministries, affected by the power cuts, started second guessing the six month fix. There was a general sense that TANESCO and MEM, following the World Bank procurement procedures and relying on concessionary loans, were not able to deliver projects on time to address the shortages. As noted previously, the cost of unserved electricity to the economy was high and therefore Tanzania paid dearly for no power. Thus, the backdrop of the IPTL agreement appears to have been a failure to deliver on the Master Plan and hefty associated costs for many Tanzanians facing loss of services, TANESCO facing loss in revenue, and the Tanzanian economy facing loss of productivity, together with a clear interest in collaborating with Malaysian investors in the context of South-South partnerships. Ultimately, the sector suffered from poor planning and execution, which interfered with the one plant solution and the original Master Plan.

It is difficult to fully assess the impacts of the overall ESI reform process on the IPPs. The IPP deals were concluded, despite the postponement of the unbundling of TANESCO, its privatisation, and the establishment of the regulatory agency. Thus, the sequencing of the reforms did not follow the standard prescription outlined in Chapter two. Although such a sequence, to take just one example, may ultimately enhance the transparency of procurement processes by having the regulator precede IPP bids, it was not followed in Tanzania due to the realities of the day: immediate generation required amidst drought conditions. The private management contract for TANESCO initially improved its financial position, and the utility was in a better position to service its PPAs – however, persistent drought conditions changed. Initially, the GoT stepped in to assist TANESCO with approximately 30 per cent of the charges, however, as of mid-2007, GoT shouldered 100 per cent of the charges, which is expected to continue until such time that TANESCO recovers (via its Revenue Recovery Plan).

In reflecting on reforms, stakeholders provide a range of comments. Some assert that full implementation of reforms would have radically changed that status quo. The country could have had cheaper power, including possibly sourced from the Southern African Power Pool, and may not have faced the same level of emergency situation as it did through 2006. Others argue that reforms may not have altered the present condition of the ESI. The drought and political interference could have easily sabotaged any Master Plan and attempts to screen projects by an independent regulator.

Stakeholders insist further tariff increases are necessary to deal with the increasing costs of generation with reliance on more costly IPPs. However, these increases have a high cost to the economy and society, as Tanzania is trying to make industrial tariffs competitive with neighbouring countries and residential customers have already experienced a tripling of residential bills in the last three years (see Appendix B). The need for further tariff increases - effectively a result of IPTL's high construction charges, Songas' high interest charges, delays in conversion of IPTL, and ostensibly high private sector returns - flies in the face of promises to the public that tariffs would decrease rather than increase with reforms. Notably, electrification rates have not increased, as revenue gains are going to pay for more costly generation rather than investments in expanding services. The IPPs filled a critical gap in supplying much needed power. However, combined IPP charges have left little for other improvements, despite the utility's doubling of revenues.

6.3 Making and breaking the Songas project

Although both the investment climate and the state and management of the electricity sector go a long way in explaining development and investment outcomes, a series of project-specific factors provide even further clarity as to how and why projects have faired for the host country and investors. In terms of Songas, five main issues standout: the characteristics and the conditions of the project partners, the idiosyncrasy of the project financing, the PPA's AFUDC, the benefits of the gas agreement and the equity turnover.

World Bank put Songas on hold in 1997 after it became clear that IPTL was coming online. The World Bank only gave the go ahead for the Songas project to recommence in 2000-01, following the arbitration process (which according to some stakeholders served to cleanse IPTL and the sector of alleged corruption); it had been proven that Tanzania's demand growth could absorb capacity from both plants; and following justifications by MEM.[76] Although the root cause was the IPTL dispute, during the time that Songas was postponed, the AFUDC accumulated, reaching over US$100 million by 2003. Furthermore, all procurement processes were aborted and then restarted. While the project may not have happened without Bank support, the presence of the Bank led to a very distinct set of outcomes.

[76] The World Bank exerted significant pressure on GoT to cancel the IPTL plant. According to MEM and World Bank personnel, the Bank made no attempt, however, to cancel the Songas project for the following reasons: it fit the Power System Master Plan; cost of production was comparatively favourable; and there were no allegations of corruption.

The GoT, Songas' largest lender (on-lending the World Bank and EIB funds to the project company) has supported the project extensively. The financing agreement was that the World Bank would on-lend to the Government of Tanzania, which would in turn on-lend to the project at a higher rate, in an attempt to move TANESCO toward commercialization. With TANESCO facing financial constraints, particularly since May 2005, the terms of finance have been readjusted, as per the 2001 subsidiary loan agreement, with government accepting a postponement of interest and principal. This agreement is presently reducing TANESCO's capacity charges to Songas by almost half. It is an arrangement that could not have happened under a commercial bank agreement, which would have most likely resulted in project default (then again, no commercial banks were available to lend to the project at the time of financing).

While the terms and conditions of the concessionary loan are currently making Songas less expensive, the buy-down of the AFUDC on the part of the GoT has also contributed to lower costs for the utility. Without the buy-down, TANESCO would currently be facing charges of US$6 million per month for turbines I-IV.

A final factor in 'making' the Songas project is the equity turnover and the emergence of Globeleq as lead shareholder. Globeleq's appetite for risk, which may be largely a function of its lower cost of capital, combined with its knowledge and experience in Tanzania has meant that the project materialized even after TransCanada and AES grew sour on the investment.[77]

6.4 Disputing and depending on IPTL

IPTL reveals an equal range of factors that have affected outcomes. Project partners have also made a significant imprint on the project as has the project finance and the fuel type and agreement. Among the most visible factors related to IPTL, however, has been the allegation of corruption. According to numerous stakeholders, it was bribery that helped seal the deal between IPTL and the GoT, causing inflated project costs, postponement of Songas, and ultimately arbitration and subsequent delay of IPTL. An attempt by TANESCO to cancel the plant based on corruption, however, failed, and the utility did not pursue further investigation, as offered by ICSID (2001). Similarly, an investigation into corruption led by GoT was completed, but charges were never pursued. The legacy of the alleged corruption is that today Tanzania has a plant with construction costs that are among

[77] Stakeholders in GoT have indicated that Songas would have gone ahead after AES's exit even without Globeleq or a 'Globeleq type firm'. At the time that AES exited, construction was nearly complete. GoT would therefore have completed construction with funds from the escrow facility. Furthermore, provided AES had not found a willing buyer and opted to leave the project, the GoT would not have been required to pay down the AFUDC. There would be no ROE expected and the capacity charge would have dropped to US$2 million for the original scope (turbines I-V).

the highest for similar size/technology IPPs in the developing world for no particular reason (other than poor planning and/or execution). On the other hand, it has a plant that did reduce the country's load shedding during acute power shortages, serving as an important insurance policy, and has since been termed "a saviour", even by stakeholders who indicate that corruption was likely.

In terms of the project partners, local partner VIP took IPTL to court shortly after the plant commenced commercial operations due to oppression by the majority shareholder, alleged business fraud and failure by Mechmar to contribute equity. VIP has also since objected to an attempt by IPTL to devalue VIP's shares. The dispute, which reflects the poor investment outcomes for the local partner, may also ultimately impact on the project debt, due to the fact that VIP has petitioned to cancel the recent sale of the project's debt to Standard Chartered.

Project financing, which was initially hard to come by, is at the root of the local partner's dispute, with VIP arguing that the project was financed 100 per cent by debt. IPTL management counters this allegation insisting that Mechmar did contribute equity, but the project became highly indebted during the arbitration period (1998-2001) and therefore the project was required to devalue shares. As of the writing of this report, these issues remain unresolved.

IPTL's use of fuel is equally contentious. Although conversion to natural gas was specified in the 1995 PPA, the plant continues to run on HFO, which means the energy charge is at least 25 per cent more expensive than it would be if it were running on domestic gas sourced from Songo Songo. Although initially the most common reason cited for the delay in conversion was the lack of precedent, as the specific type of engine has never been converted before. Here again, however, poor planning and execution among the diverse stakeholders has played a serious role, together with the ongoing disputes and negotiations related to the project's debt and equity. Signs now point to the fact that GoT will purchase the debt, and most probably the equity as well, with conversion slated thereafter (provided there is sufficient capacity at the gas processing plant). Mothballing remains a remote possibility for this plant in the interim.

In closing, it is important to emphasize that although charges have been remarkably high, they do remain less than the cost of unserved energy, and therefore do not negate the more recent perception (throughout much of 2005 and 2006) of IPTL as a well run plant that has saved the country from power shortages.

7. Conclusion

Tanzania's IPPs were born out of the push for private participation, led primarily by the World Bank, and supported by international consultants and domestic champions of the new model for power sector reform. IPPs were only one part of the reform package, which, as initially laid down in the Power VI project, tied the development of the 180 MW Kihansi Hydropower station to power sector reforms, including plans for restructuring the sector and introducing of private participation into both power and natural gas development. A duplication of IPP efforts, however, ultimately undermined the effectiveness of the plants and may have been among the significant contributing factors for slowing reform plans, including TANESCO being removed from the list of utilities specified for privatization.

In the end, neither the IPP development outcome nor the investment outcome has been stellar. Furthermore, no balance appears to have been achieved between the two, which has translated into a sense of precariousness with regard to individual projects as well as how IPPs relate to the sector, rather than any sense of long-term sustainability. Interestingly enough, however, the general perception by the public and public sector is that the outcome for investors has been highly profitable (at the country's expense), whereas most investors see the development outcomes as far outweighing any investment rewards. There is general agreement, however, that Tanzania's gas industry is developing, which is a benefit to stakeholders across the board, due to lower fuel prices and greater security of supply.[78]

The IPTL arbitration, which in turn led to contract changes, was prompted by a perceived imbalance between the development and investment outcomes, namely that investment gains weighed too heavily against the country stakeholders. However, the aftermath of the arbitration has still not brought a complete sense of satisfaction to the deal makers. Changes to Songas' capacity charges via the buying down of the AFUDC also led to a greater balancing, however, in contrast to most other rebalancing acts, it was the government (rather than the sponsor) that made the compromise by absorbing what would have otherwise been passed on to the rate payer.

The suboptimal developmental outcomes may be attributed to the investment climate and the perceptions of risk, poor planning processes, no clearly articulated private power framework, together with the lack of regulatory oversight and possible corruption. Factors contributing to the suboptimal investment outcome appear to be primarily related to project delays, which may be linked in turn to allegedly corrupt or poor business practices and poor planning and execution. Project sponsors together with a unique set of financing arrangements have also made significant impacts on outcomes along with the fuel arrangements for each plant. Projects have survived these stresses through equity turnover, and refinancing. A striking feature of Tanzania's IPPs is that none has failed outright. Instead, government stakeholders have intervened to buoy projects, including, as

[78] With prices capped at 75 per cent the liquid fuel equivalent, however, there is a risk that investors may not see a clear incentive for future development of the field. PanAfrican Energy Tanzania Limited has not, however, indicated any such concern.

mentioned above, via the buying down of Songas' AFUDC, and firms such as Globeleq have identified projects as new market opportunities.

Despite the mixed results, the MEM together with TANESCO indicated, in the first quarter of 2006, that they planned to put more IPPs on the ground. At that time, although the terms and conditions were not determined, officials insisted that they would be different from those for the existing plants. What ensued, however, was a deal struck with Richmond, which as noted in section 2, ultimately only delivered the contracted capacity once GoT intervened to help airlift the engines. Kiwira coal mine has also failed to deliver, after not raising the necessary finance. Once again, emergency power was brought in to plug shortages. Although conditions were to be different than those of existing plants, procurement processes for neither Richmond nor Kiwira followed international competitive bidding processes, with EWURA providing no oversight due to the fact that it came into existence only after the fact. In the case of Richmond, again, corruption allegations were made, which although since cleared, still raise doubts about due process being followed.

8. Lessons learned and steps forward

On the one hand, neither the development nor the investment outcomes have been particularly positive. Both IPPs have been more costly and more time consuming than originally expected.[79] On the other hand, with the persistent drought conditions through 2006, Songas and IPTL became indispensable. What then are the lessons learned from this experience and possible steps forward?

1. *Power sector planning coordination*: Tanzania's ESI was a victim of poor coordination. Coordination among different ministries, stakeholders and donors broke down during the negotiation of Songas and IPTL. This poor coordination cost the country dearly in terms of time and its many associated costs. Although it is easy to point fingers in hindsight, unless basic issues related to coordination are addressed then there is a risk of history repeating itself.

2. *Power sector reform priorities:* An inevitable consequence of poor coordination is that power sector reforms have been neither clearly prioritized nor implemented. Specifically, a clear policy framework for private sector investment in the power

[79] If the currency devalues, imported fuel prices mount, and/or IPTL experiences further conversion delays, there could even be greater costs. Promising developments that may help reduce costs in the near term are: the buyback by GoT of IPTL's debt as well as the refinancing of Songas' expansion, which will help reduce capacity charges; the imminent conversion of IPTL from HFO to natural gas, which will translate into a 25-40% reduction in the energy charge.

sector remains outstanding, including the target percentage of private generation, standard investment incentives and contractual norms for the PPA. Also outstanding is a clear and feasible roadmap for how to make the main off-taker financially and technically viable. Instead the sector has gone from dealing with crisis after crisis (first drought, then high capacity charges, now drought again), delaying the planning and execution of fundamental reforms necessary for the long-term sustainability of power supply and expansion in Tanzania.

3. *Independent regulation:* Several investors, among them those operating in Tanzania, have cited the importance of an independent and strong regulatory body for project success. Not only does it facilitate transparency in initial project dealings, the existence of a strong and independent regulator ensures legitimacy long after COD. Legislation to establish a regulator in Tanzania was passed in 2001, but EWURA only became active in 2006, after a new round of private power had been contracted. There has therefore been minimal oversight of the IPP process to date. This fact may have cost the country past and present investments and may ultimately impact on future investments.

4. *Competitive bids and process:* With a crisis-based approach to power sector reform and planning, the competitive bidding process that is often instrumental in creating transparency in negotiations was not followed. One of the consequences of not following a competitive bidding procedure is that Tanzania now has one of the most costly plants in the region. Although the IPTL deal was completed quickly, any speed gained in negotiation was lost in the subsequent arbitration proceedings. This is a particularly important lesson for countries throughout East Africa currently facing drought and the need for 'emergency power'.

5. *Arbitration:* While arbitration might be a useful process for resolving issues related to fairness, it may ultimately be a lengthy process that affects overall power sector development, particularly for countries such as Tanzania with a relatively high proportion of private sector generation.

6. *Private sector partners and staying power*: To date, private sector investment has come at an extremely high cost, not higher than blackouts, but still high. Furthermore, many sponsors have come and gone, when the risk profile of the projects changed. Many North American and European private investors retreated, and firms from developing countries (e.g. India's Tata and Reliance) as well as firms

such as Globeleq and IPS with a clearer development mandate emerged to fill the gap. These firms may, in the end, have a larger appetite for risk as well as a greater ability to diversify risk over their portfolio of assets. In this context, there is a clear need for countries to commit to the right private sector partner, and vice versa. Caution must be taken to ensure that those present at the negotiating table are looking for a long-term mutually beneficial relationship, which will allow both investment and development outcomes to flourish.

7. *Currency devaluation and local capital:* A final observation and lesson is that although Tanzania has not experienced major macroeconomic shock and a radical depreciation of its currency, throughout the 1990s, the currency lost significant value. With PPAs denominated in USD, there is a potentially substantial impact of depreciation on the cost of power in local terms, particularly given the 20-year duration of contracts. The use of local capital is emerging as a solution to mitigate the impact of currency depreciation. Examples are evident in North Africa, particularly in Morocco, which has recently completed an IPP 100% financed by local capital. Although Tanzania's financial markets may not yet be sufficiently deep to finance IPPs 100%, steps may be taken in this direction in partnership with foreign investors and donors to work toward greater country ownership of projects.

Appendix A: Project costs

Table A.1: IPTL project costs

IPTL		Project costs (US$ million)	Financing	
Projected total project cost		163		
Actual total project cost (post-arbitration)				
	EPC Contract	98.2	70% debt (at 8.5%)	30% equity
	Construction contingency	4.9		
	Land	1		
	Insurance	4.1		
	advisors (lenders, project)	3		
	working capital	1.7		
	fuel oil reserve	3.2		
	interest during construction	4.6		
	financing & agency fees	1.9		
	misc[1]	4.6		
	total project costs for diesel	**127.2**		
Conversion to natgas				
	estimate in ICSID	11.6		
	2005 estimation by Wartsila	20	TANESCO	
Total project costs post conversion		**147.2**		
NOTE: [1] Misc includes funds termed 'development', 'mobilization and 'commitment fees'				
Source: ICSID, MEM, TANESCO				

Table A.2: Songas project costs

Songas		Project costs (US$ million)	Financing	
Initial Songas costs				
	gas processing and pipeline	100	70% debt (on-lent by GoT at 7.1%)[1]	30% equity
	assumed loans for turbines 1-4 (115 MW)	45		
	work done on wells	25		
	Overhaul/refurbishment and conversion of turbines 1-4	35		
	balance of plant costs[2]	61		
	total for 115 MW project, delivered July 2004	**266**		
Songas expansion				
	turbine 5 (35 MW)	7.1	100% equity (Globeleq)[3]	
	turbine 6 (40 MW)	14		
	balance of plant costs for expansion	28.9		
	total for 75 MW expansion	**50**		
	total on which (2005/present) capacity charges calculated	**316**		
Additional Songas costs incurred by GoT				
	drilling of original wells	100	Sunk cost, GoT (concessionary loans 1970s)	

	AFUDC	103	Treasury (40%), TANESCO (10%), Escrow (50%)
	escrow account	50	surcharge on fuel (used to pay down AFUDC), presently now only US$2.5 million
	liquidity facility of 4 months capacity on 115 MW	16.8	interest on the escrow
	total additional costs	**220**	NOTE: does not include escrow since used to pay down AFUDC
Total project costs		**536**	

NOTE: [1] **Songas equity:** Total equity for original scope is US$60 million. Globeleq (US$33.8 million), FMO (US$14.6 million), TDFL (US$4 million), CDC (US$3.6 million), TPDC (US$3 million-in kind) and TANESCO (US$1 million-in kind). **Songas debt:** Total debt is US$206 million. IDA (US$136 million), EIB, (US$55 million), Sida, (US$15 million). In reference to the IDA loan, US$108 was sourced from the World Bank Credit 3569-TA. In addition, the old loans from previous credits and grants include US$22 million (salvage value) for UGT3 and UGT4 LM600 GE turbines installed at Ubungo in 1995; and US$8 million paid out of the Sixth Power Project for Songo Songo wells work-overs in 1996/7. Sida contributed a grant to GoT but the loan to Songas equivalent to US$15 million (salvage value) for UGT1 and UGT2 ABB GT10A in 1994.
[2]balance of plant costs' refers to refurbishment of plant, building of warehouse, as well as soft costs, e.g. project management, build up of O&M, [3]refinancing of turbines 5 & 6 currently under discussion
Source: PAD, Songas personal interviews, TANESCO, MEM

Appendix B: TANESCO tariffs

Tariff revisions and restructuring have been a key subset of TANESCO's commercialization. Tariff reforms have focused on: i) increasing tariffs toward commercial rates and in line with inflation, ii) reducing the cross subsidy from industry to domestic consumers, and iii) reducing the lifeline tariff subsidy for domestic and light commercial customers. These changes were initiated in the early 1990s and then ramped up again under NETGroup Solutions management of TANESCO since 2002.

Up to the mid-1980s electricity tariffs were generally in line with supply costs. However, post-1986 when Tanzania began its Structural Adjustment Program, the real value of electricity tariffs eroded, as tariff revisions did not keep pace with prescribed currency devaluations (Wangwe, Semboja et al. 1998). An average tariff of 11 USc/kWh in 1985 eroded to 5.5 US/kWh in 1992. Tariff revisions in the 1990's raised the average tariff to 9.3 USc/kWh by 1995 and 10.3 USc/kWh in 1998, indicating a strong tariff throughout most of the decade. The real value of the average tariff eroded again to 7.0 USc/kWh by 2001 due to inflation (Katyega 2004). Under the management of NETGroup Solutions, average tariffs increased from 7.0 USc in 2002 to 7.6 USc/kWh in 2005 (Katyega 2004 and calculations by authors based on unpublished TANESCO data).

In 1993, the cross-subsidy from industry to domestic amounted to the average residential tariff being only 30% of industrial customers (Wangwe, Semboja et al. 1998). Extensive efforts to reduce the industrial cross-subsidy began with the tariff revision just prior to NETGroup Solutions assuming TANESCO's management in May 2002. The 2005 average residential selling price was 160% of the average high voltage selling price, largely undoing earlier cross-subsidy (calculations by authors based on unpublished TANESCO data).[80] Tariff restructuring was aimed at reducing Tanzania's industrial energy tariffs to be competitive with its neighbours, Uganda and Kenya, in order to improve prospects for foreign investment in the country.

In 1992, residential and light commercial customers enjoyed a formal lifeline subsidy of 1,000 kWh per month. However, the effective lifeline level had reached 2,500 kWh with the erosion of real tariffs with inflation (Hosier and Kipondya 1993). The lifeline subsidy was decreased to 500 kWh in 1995 and then again to 100 kWh in 2002. In 2004, under NETGroup Solutions, the lifeline tariff was decreased from a 100 kWh universal subsidy to a 50 kWh per month targeted subsidy.[81]

As a result of tariff rebalancing and restructuring (i.e. increases in the average tariff, reduction in cross-subsidy, and decrease in the lifeline tariff), industrial consumers have seen their tariff decrease while domestic consumer have seen their tariffs rise. Between 2002 to 2005, the average high voltage selling price decreased from 7.6 to 5.2 USc/kWh. The average residential selling price increased from 6.9 to 8.2 USc/kWh during the same period[2] (calculations by authors based on unpublished TANESCO data)

Notably, residential consumers have seen significant increase in rates, particularly those experiencing a loss of lifeline subsidy benefits. For example, residential customers of 100 kWh per month have experienced a tripling of their monthly bill for the same amount of electricity comparing December 2005 to January 2002. Meanwhile, the consumer price index has increased 1.2 times since January 2002 (calculations by authors based on unpublished TANESCO data, data from National Bureau of Statistics), i.e. the increase in electricity tariffs is more than twice rise in the CPI.[82]

[80] Average selling price is calculated as billing (in TSh) divided by sales in (kWh).

[81] As of December 2005, the 50 kWh/month lifeline subsidy is only given to consumers with total consumption of less than 275 kWh/month.

[82] Values given above are exclusive of value added tax (VAT), customers additionally pay a 20% VAT.

Appendix C: Production sharing agreement

Under the Production Sharing Agreement (PSA) between Tanzania Petroleum Development Corporation (TPDC) and PanAfrican Energy Tanzania Limited, profits are shared on production with respect to 'additional gas' only. Additional gas is defined as all gas other than that 'protected gas' designated for Ubungo turbines I-V (150 MW) plus the cement factory for the 20-year PPA.

Table C.1: PSA between TPDC and PanAfrican Energy Tanzania Limited

Average daily sales	**Share of Proven Section Profit Gas Revenues %**	
MMcfd*	**TPDC**	**PanAfrican Energy Tanzania Limited**
0-20	75	25
>20 $\leq$ 30	70	30
>30 $\leq$ 40	65	35
>40 $\leq$ 50	60	40
>50	45	55

Source: Orca (2007:9)

Profit sharing for gas in the as of yet unproven section of Songo Songo, will, regardless of average daily sales, be divided on the following terms:
TPDC: 45%
EastCoast Energy: 55%

Appendix D: Explaining IPTL conversion delays

With regard to delays related to reserve probability and availability, East Coast Energy and TPDC, the joint operators and retailers of the gas field have indicated that there are sufficient proven reserves to supply Ubungo and the cement factory with gas for 20 years. Reserves required to supply IPTL as well as two additional plants expected to be put up by TANESCO by 2007 (for 20 years) are currently characterized as probable, but both parties indicate that further exploration is underway (expected by mid-2006) to bring 'proven + probable' (P2) reserves up to 'proven' (P1) level of certainty. Thus while reserve availability is expected, it remains outstanding.

Table D.1: Songo Songo gas reserves quantity and allotment

Reserves	Certainty	Quantity	Sufficient for plant (assuming 20 year PPA and >85% capacity utilization)
Proven (P1)	95%	540 Bcf	Ubungo (I-VI) plus cement factory (estimated that require 400 Bcf)
Proven + probable (P2)	50%	649 Bcf	Ubungo, IPTL conversion, 45 MW plant*, 60 MW plant*
Proven + probable + possible (P3)	10%	875 Bcf	Ubungo, IPTL conversion, 45 MW plant*, 60 MW plant*, additional 100-300 MW plant**

Source: Compiled by authors based on data provided by East Coast Energy and Tanzania Petroleum Development Corporation, November 2005
NOTES: *TANESCO plants, **potentially another IPP

Another factor contributing to the delay in conversion is the technology itself. Assuming the gas is available, the engines need to be converted, but Wartsila SWD 18 V 38 diesel engines have never run on natural gas. Thus Warsila, which is also the operator of IPTL, must conduct a series of tests. Although according to one stakeholder close to the project, "this is not rocket science" a test-bench must be booked and time allotted to carry out the work.

Before carrying out any tests, two critical steps must be taken: securing financing (which has been recently concluded, but was allegedly itself delayed via a World Bank loan) and securing the permission of the lenders. It was indicated that commercial banks (Bank Bumiputra Malaysia Berhad--now Bank Bumiputra Commercial Bank--and SIME Bank) which provided debt for IPTL resisted the conversion due to technological risk, namely that post-conversion the engines may not perform which could result in losses to the project. IPTL management disputes the allegation that lenders have resisted the conversion, but their permission is needed, which requires a lengthy application. IPTL management has—as of mid November 2005—received the necessary application on behalf of TANESCO to request the conversion.

Yet another factor cited as delaying the conversion from sources close to the project is the formula for pricing the fuel. Some stakeholders allege that the fuel formula is based on product being sourced from Singapore, however, IPTL may be obtaining product from the Arabian Gulf, implying that the firm is making a profit on the freight difference. IPTL management has denied this allegation, arguing that TANESCO was previously invited to assume the fuel procurement but ultimately rejected this task, implying that it was not beneficial to the utility (sources within TANESCO have confirmed that they did not wish to assume the risk of procuring fuel, and that they saw no benefit in the function). Presently TANESCO is observing the fuel procurement on behalf of IPTL.

Lastly, disputes related to renegotiation of IPTL ownership have both hindered conversion: local partner, VIP, has sought to wind up the project since February 25, 2002 (a month after the project reached COD) and IPTL has recently sold (as of November 2005) its debt to

Standard Chartered (although this is currently being contested by VIP). Presently the GoT is in talks with IPTL potentially to acquire the IPTL debt.
Of these six issues related to the IPTL conversion delay, it is the unprecedented process of converting the technology that is cited most commonly by stakeholders.

Appendix E: Comparing construction costs

Table E.1. IPTL construction costs versus small diesel IPPs in developing countries

Country	Capacity MW	Project Cost US$ million	Capacity Cost US$/kW	Project Name
Dominican Republic	105	40	381	Boca Chica Power Barge
Côte d'Ivoire	99	70	707	Compagnie Ivoirienne de Production d'Electricite (CIPREL; Vridi Gas-Fired Power Plant; Valener)
Brazil	103	76	738	Juiz de Fora
Thailand (1)	107	85	794	Gulf Cogeneration Co Ltd (Kaeng Khoi Gas-Fired Power Plant)
Thailand (2)	100	80	800	Laem Chabang Power Company
Philippines (1)	100	83	830	Clark Air Base Diesel Power Plant
Hungary	95	80	842	Debrecen (DKCE)
Panama	96	88	917	Pan Am Thermal Generating Ltd. (La Chorrera Power Project)
India	106	97.6	921	Samayanallur Power Project
Thailand (3)	107	98.8	923	Bangkok Co-Generation Company Ltd.
India	106	102.2	964	Samalpatti Power Co.
Thailand (4)	96	96	1,000	Bangchak Power Company
Philippines (2)	105	105	1,000	Subic Bay Plant
Philippines (3)	98	110	1,122	Iligan City Diesel Plant I & II
Kenya (1)	56	65	1,161	Iberafrica
Philippines (4)	100	120	1,200	Zamboanga Diesel Power Plant
Tanzania, IPTL	100	127.2	1,272	IPTL, Post-Arbitration
Tanzania, IPTL	100	163.5	1,635	IPTL, Pre-Arbitration
Tanzania, IPTL	97.4	150	1,540	IPTL, PPI reported

Source: Calculated by authors based on data from World Bank (2004) and Gratwick and Eberhard (2005)

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Over 30 interviews were conducted with more than 20 stakeholders in January, February, August, November and December 2005 in Dar-es-Salaam, Washington D.C. and via teleconference in London. Interviews were followed by email correspondence to clarify discussion points, with the last review of data conducted in September 2007. Stakeholder interviews included present and former directors and managers at Artumas Tanzania (Jersey) Limited (ATJL), Orca Exploration, IPTL, Songas, EWURA, MEM, PSRC, TPDC, VIP, TANESCO, NETGroup Solutions, Sida, and the World Bank. Due to sensitivity of data, the names of stakeholders, who have been the primary source of data for this paper, have largely been left out of the discussion; most stakeholders are only identified, if at all, by organizational affiliation in the text.

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- Independent Power Tanzania Limited (IPTL)
- Songas
- EastCoast Energy
- Ministry of Energy and Minerals (MEM)
- Parastatal Sector Reform Commission (PSRC)
- Tanzania Petroleum Development Corporation
- VIP Engineering Limited
- TANESCO
- NETGroup Solutions
- Swedish International Development Cooperation Agency (Sida)
- World Bank

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