

**Supplementary files for:**

## A review of private investment in Tanzania's power generation sector

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### Power sector reform in Africa: drivers and current status

Côte d'Ivoire became one of the first African countries in 1994 to attract a foreign-owned IPP to sell power to the grid under a long-term contract with the state utility (Gratwick & Eberhard, 2008; Eberhard et al., 2017). Ghana, Kenya, Nigeria, Senegal, Tanzania and Uganda also opened their doors to private sector participation (Eberhard et al., 2017).

Although IPPs were considered part of a larger power sector reform program, the reforms were not far-reaching. In most cases, state utilities remained vertically integrated and maintained a dominant share of the generation market, with private power invited only on the margin of the sector. Exceptions are Côte d'Ivoire and Tanzania, where IPPs have contributed significantly (more than 50%) to overall electricity production. Togo's first IPP, Centrale Thermique de Lome, increased the country's supply by 67 percent when it came on line in 2010. Policy frameworks and regulatory regimes necessary to maintain a competitive environment were limited. International competitive bids (ICBs) for those IPPs that were developed were often not conducted because of tight timeframes, resulting in limited competition for the market; and long-term PPAs eliminated competition in the market. These long-term PPAs and often government guarantees and security arrangements, such as escrows and liquidity facilities, exposed countries to significant exchange-rate risks (Eberhard et al., 2017). Although Africa experienced a continuation of private participation in greenfield electricity projects, private investment has been erratic, with a spike in 2007 largely caused by the financial close of one large project, Bujagali, followed by a trough and then another flurry of activity from 2012 onward (Eberhard et al., 2016).

Several factors explain the recent trends in investment. Private sector firms were deeply affected by the Asian and subsequent Latin American financial crises in the late 1990s (Eberhard et al., 2016). The Enron collapse and its aftershocks also featured prominently in influencing American and European-based firms to reduce risk exposure in emerging and developing-country markets and refocus on core activities in their countries of origin. The financial crisis of 2008/9 also had its toll – reducing investment flows into the sector. Furthermore, DFIs began to reconsider their position of restricted infrastructure investment, which had predominated throughout the 1990s. Two different categories of DFIs should, however, be distinguished, namely those which lend on commercial term and largely to private companies (e.g. FMO, PROPARCO, DEG and IFC) and the multilateral development banks (e.g. the World Bank and the African Development Bank) which lend on concessionary terms and primarily to public sector projects. It is the latter that re-focused on infrastructure. As concessionary funding became available again, many countries opted for a hybrid solution — part public, part private (Eberhard et al., 2016). Kenya represents among the clearest examples, with KenGen, the state-owned generator, building alongside IPPs, with support from DFIs (Eberhard & Gratwick, 2013).

Despite this revival of concessionary lending and ongoing funding from the private sector, investments are insufficient to address Africa's power needs: two out of three households in Sub-Saharan Africa, close to 600 million people, have no electricity connection at all, and poor supply is the rule, not the exception. The cost of meeting Africa's power sector needs is

estimated at \$40.8 billion a year, equivalent to 6.35 percent of Africa's GDP. Approximately two thirds of the total spending is needed for capital investment (\$26.7 billion a year); the remainder is for operations and maintenance (O&M). Of capital investment, about \$14.4 billion is required for new power generation each year, and the remainder for refurbishments and networks (Eberhard et al., 2011: 60). Existing investment is far below what is needed (Castellano et al., 2015). Approximately 80 percent of existing spending is domestically sourced from taxes or user charges. The rest is split among Official Development Assistance (ODA) financing (6 percent of total), non-Organisation for Economic Co-operation and Development (OECD) funding (9 percent of total) and private sector investment (4 percent of total). Tackling existing utility inefficiencies, which include system losses, under-pricing, under-collection of revenue and over-staffing would make an additional \$8.24 billion available, but a funding gap of \$20.93 billion would still remain (Eberhard et al., 2011).

It follows that closing Africa's power infrastructure funding gap inevitably requires undertaking reforms to reduce or eliminate system inefficiencies. This will help existing resources to go farther and create a more attractive investment climate for external and private finance, which still has the potential to grow.

### **Energy Sector Regulations**

The mandate for these regulations was given in Clause 5 of the Electricity Act (2008): "The Authority shall have powers to: (i) award licenses to entities undertaking or seeking to undertake a licensed activity; (ii) approve and enforce tariffs and fees charged by licensees; (iii) approve licensees' terms and conditions of electricity supply; and (iv) approve initiation of the procurement of new electricity supply installations." The rules came into effect as of January 1, 2015, and will affect projects presently under negotiation, but not existing IPPs (that is, Songas and IPTL).

### **Gas reserves: technical notes**

According to the resource classification standards employed in the petroleum industry, the term "reserves" refers to those volumes of gas that are commercially recoverable from known accumulations (SPE 2011). While not all announced reserve figures adhere to this strict definition, the commerciality tests for gas reserves normally require the existence of an established market, available infrastructure, and an approved field development plan. The term "proved reserves" refers to those reserves that are reasonably certain to be recovered, and "probable reserves" denotes gas volumes that are more likely than not to be recovered. The sum of proved and probable reserves, denoted as 2P reserves, is often considered a "best guess" estimate of ultimate recovery from commercial fields.

### **Songas**

Songas is part of the Songo Songo gas-to-electricity project, a US\$316 million project that encompasses the Songas power plant in Dar-es-Salaam, a natural-gas-processing plant on Songo Songo Island, a 225-kilometer (km) pipeline from the island to Dar-es-Salaam, and rights to two onshore and three offshore natural gas wells at Songo Songo Island. The gas-processing plant and pipelines were built and are owned by Songas Ltd., a local joint venture company which, following a number of transactions, was formed by the power company, the Commonwealth Development Corporation/Globeleq, TANESCO, the Tanzania Petroleum Development Corporation, and the Tanzania Development Finance Co. Ltd. Globeleq has the controlling interest in the project, including the electric power project (which was expanded by the consortium), and the wells are operated by PanAfrican Energy Tanzania Ltd, a local

subsidiary of Orca Exploration Group Inc. Construction of the pipeline network was completed in May 2004, and the project started commercial operation in July 2004. The network transports natural gas to Dar-es-Salaam, where, apart from the Songas power plant, it is used as the principal fuel for turbine generators at TANESCO's Ubungo I and II power plants (102 and 105 MW, respectively), as well as its 45 MW Tegeta plant. Other outlets for the gas include the Twiga Cement Factory (Wazo Hill) and an electrification project that generates electricity for villages along the pipeline route. The Mtwara Energy Project (MEP), formerly a remote rural gas-to-electricity generation and distribution concession, reverted back to TANESCO's control in 2012 after two years of operation, due to a mismatch between operating costs and revenue (TANESCO, per. comm., January 14, 2015).

### **Songas vs. IPTL: A tale of two plants**

The Songas and IPTL tale unfolded in the early 1990s in Tanzania. The story was well documented (Eberhard et al., 2016; Gratwick et al., 2006), and may be summarised as follows: two plants were procured at the same time, albeit via different procurement channels - Songas through internationally competitive bidding (ICB) and IPTL through direct negotiation. A disagreement with IPTL subsequently led to arbitration, which in turn prompted Songas to halt development as stakeholders were wary that the sector could absorb power from both plants. After renegotiation of the IPTL contract, scaling back of the initial Songas design and a change in shareholders, both plants were ultimately completed. In the years since, power has been supplied by both Songas and IPTL, with IPTL power being considerably more expensive due to both higher imported fuel charges and capacity charges.

Despite the original plan dating to 1995 and reinforced in the 2001 arbitration, IPTL has still not been converted to run on natural gas. In 2008 this conversion cost was pegged at US\$20 million. By 2014 there was no cost estimate available and no date set for conversion (TANESCO, per. comm., November 2014). One of the impediments to the conversion is that while the ICSID tribunal was concluded, legal issues related to project sponsors stymied further developments.

Another plan was for the government to buy back IPTL's debt; however, this has not materialized. Furthermore, controversy surrounded the sale of IPTL to Pan Africa Power Solutions (PAP) and the subsequent transfer of funds from the Bank of Tanzania (escrow account) to PAP. According to TANESCO, there is no near-term plan to convert IPTL to natural gas.

The lessons from Tanzania's experience with IPTL could not be more explicit. When power is not planned, procured, and contracted transparently and consistently, the implications are potentially grave, far-reaching, and ongoing. Rather than being considered a planning and procurement mishap, however, IPTL is often used to emphasize the drawbacks of private sector participation. Meanwhile, Songas has not been widely recognized as a successful competitive bid or as an example of how the private sector can work strategically to harness more power. Instead, it has been charged with having advanced private interests at the expense of the state, including obtaining key assets such as pipeline infrastructure that are in the strategic interests of the country.

## **Symbion following IPTL**

At its inception, the Symbion case seemed to replicate some of the planning, procurement, and contracting issues experienced around IPTL. Originally specified for a two-year contract to plug an immediate power shortage in 2006, Symbion Ubungo (a 126 MW project previously known as Richmond/Dowans) continued to operate for 10 years despite no long-term contract being in place. At the time of writing, despite a 15-year PPA finally being signed, controversy continues.

Agreement was struck, in a nontransparent manner, with Richmond, a special purpose vehicle (SPV) formed in 2006 to provide 100 MW of emergency power. The contract was stipulated for two years starting in September 2006 (20 MW) followed by the balance (80 MW) by February 2007, which was safeguarded by a government guarantee. The first 20 MW (of the 100 MW) was, however, brought online in October 2006, and fueled with natural gas supplied by Songo Songo. This occurred 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 United Arab Emirates (UAE), subsequently bought the plant and took over the contract, and saw the addition of 60 MW capacity, albeit only by August 2007—six months later than expected. When the plant finally came online it was not fully functioning and by the time all issues had been resolved Tanzania was no longer in need of the power, yet it was legally contracted to purchase it or pay penalties. The Richmond/Dowans fallout led to the resignation of then–prime minister Edward Lowassa and two other ministers on charges of alleged associated corruption in 2008. In 2011, Dowans sold the plant to US-based Symbion Power. Electricity has consistently been sourced from Symbion in the years since, particularly with the power shortages from 2011 to 2014, and additional capacity of 46 MW was added to bring it to its current total of 126 MW.

Finally, in 2016, Symbion signed a 15-year PPA with TANESCO; however, the Government objected as its goal was to retire all EPPs. TANESCO in turn withdrew the PPA, which Symbion protested. The issue is presently unresolved, and, as of the time of writing, no power is being purchased from Symbion.

## **Wind East Africa (Singida 100 MW) vs. NDC (Singida 50 MW)**

In 2004, TANESCO, in collaboration with the Danish government, identified stimulating investment and harnessing Tanzania's wind power as priorities. TANESCO invited any party (through an open, general invitation that does not necessarily fall under the definition of international competitive bidding) to develop wind projects. Five entities came forward, including the precursor to Wind East Africa (Singida 100 MW), as well as two of the partners that since formed the alternative Singida 50 MW project (namely National Development Corporation [NDC] and Power Pool East Africa Ltd; TANESCO is also a participant). Initial wind-mapping studies were undertaken by Wind East Africa, though there was little in terms of project development by either the sponsors of Wind East Africa (100 MW) or Singida (50 MW). In 2009, Aldwych International, a U.K.-based private IPP firm with a focus on Africa, joined the Singida 100 MW project.

Momentum picked up, including the engagement of the World Bank and the IFC. Despite the involvement of Aldwych, the World Bank, and the IFC, the project stalled. Meanwhile, the Singida 50MW project was identified among near-term PPPs for TANESCO.

Delay and hesitation surrounding the wind projects were partly because at 11–12 USc/kWh, the cost of power was higher than for power generated with domestic gas (at 6–7 USc/kWh). With more gas expected to come on stream, there was an argument that wind power was not competitive. While Wind East Africa made progress (and Singida 50 has since been stalled), the question arises as to why such extreme delays occurred —almost 12 years and counting since Wind East Africa expressed interest.

Another key feature of the wind story is the relationship between the two projects, with Wind East Africa viewed to be in competition with Singida. There was no reason for the two projects to be pitted against each other for multiple years; they could have instead been phased in one after the other or undertaken simultaneously.

The wind story provides further evidence that the lessons of the IPTL debacle have not been internalized by key stakeholders. Various factions compete within state agencies, based on vested interests; and transparency remains compromised, despite efforts to embolden the EWURA with regulatory powers.

### **Challenges and prospects in the gas sector**

There is a long-running dispute between PAT and the TPDC at Songo Songo related to cost-recovery and their existing production-sharing agreement. TANESCO also owes PAT approximately US\$60 million, which has prevented it from undertaking further investment in gas development. Progress has been made (although not yet finalised) on a new gas contract between the parties, and the plan is to expand production from Songo Songo by approximately 100 mmscfd, which could be sufficient to supply around 400 MW of open-cycle gas turbine (OCGT) capacity or 50 percent more if configured for the combined cycle.

It is envisaged that the existing Songo Songo gas infrastructure can accommodate 70 mmscfd in total. It is currently processing approximately 91 mmscfd but will revert back to its design capacity of 70 mmscfd. Any additional volumes beyond this will utilize the NNGIP. The PAT drilled an additional well in February 2016 but has not yet entered into a gas sales agreement and third-party access agreement with TPDC. Also, the significant offshore gas discoveries (of up to 55 Tcf of gas initially in place) are promising, but unlikely to be delivered onshore and available for power generation before 2022–24. The schedule for long-term gas in Mozambique, which is widely regarded as ahead of Tanzania, would suggest that long-term gas for Tanzania is likely to come after 2022. Regardless, the offshore gas is spread out along the coast and is unlikely to be landed in Mnazi Bay. A proposed LNG terminal will be built farther north, so the NNGIP pipeline may not readily serve the offshore gas without further modifications.

Thus, there is a real possibility that gas supply in the medium term will be insufficient to pay for the NNGIP investment. To compound the problem, it should be noted that EWURA played no part in the NNGIP despite it being the largest energy infrastructure project undertaken in the country to date. The project was carried out on an emergency basis, and EWURA was only asked to approve a tariff when construction was nearly completed. The Chinese ExIm loan facility of US\$2.2 billion was premised on a cost of US\$3.00 per million British thermal units

(MMBtu); however, ultimately, EWURA approved a tariff of US\$2.14/MMBtu (for gas processing and transportation), and the shortfall of US\$0.86 was to be made up by the government. By comparison, Songas' gas-processing and transportation tariff is US\$0.59/MMBtu. It should be noted that this tariff of \$0.59 is levied only on certain third-party gas that is processed and transported by Songas and is not based on the underlying capital base of the gas infrastructure. Although the pipeline is now complete, expanded gas off-take agreements and power plan investments are still to be finalized.

Parliament has only recently enacted the corresponding Petroleum Upstream Midstream and Downstream Act, which mandates a similar vetting process for the gas sector. Legislation was initiated in 2008, but the act was withheld by the Chief Draftsman's Office, and finally passed on July 5, 2015. The Act establishes the Petroleum Upstream Regulatory Authority (PURA), which is to regulate upstream gas and also lay out how competitive bidding is to be carried out. It is anticipated that it will take an additional three years for all subsidiary legislation to be designed, drafted, and enacted.

While Chinese capital financed the gas pipeline, it has not been historically involved in financing power projects in Tanzania. That may soon change. Two of the PPPs identified in the near term and noted earlier, Kinyerezi III and IV, will have Chinese equity and debt; Chinese companies have also made major gas discoveries. Singida 50 IPP would also avail Chinese funding via TANESCO's equity portion.