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Sustainable electricity pricing for Tanzania

Executive Summary

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The Government of Tanzania (GoT) is working towards the realization of its development targets, one of which is to grow its economy to reach middle-income status by 2025. Though the economic growth of Tanzania has been impressive, the country's per capita electricity consumption remains low in comparison with other countries with similar levels of total energy consumption. Tanzania's electricity consumption is constrained by a lack of infrastructure in all segments of the electricity supply chain: generation, transmission, and distribution. If left unresolved, limited availability of electricity will constrain sustained economic development and prevent the achievement of socio-economic goals.

Traditionally, power generation in Tanzania has been reliant on hydroelectricity, supplemented by oil-fired generation contracted from emergency power producers (EPPs) when required. Demand increase in the coming years is forecasted to be important, given burgeoning economic development and a government-led campaign to increase rural electrification. Increasingly uncertain hydrology, the high cost of oil-fired generation, and domestic availability of natural gas are driving the government toward an aggressive natural-gas led capacity expansion plan in the near term, to be supplemented by hydro and coal-based generation capacity in the long term. At the same time, a structural reform of TANESCO, the national utility company, is underway, with the aim of transitioning from the current single-buyer power market model to a less centralized model with unbundling occurring within all market segments (generation, transmission, and distribution).

The only two existing natural gas producers in the country mainly supply natural gas to TANESCO and other independent power producers. Songas, Tanzania's first gas project, was developed as part of a gas-to-power package and enjoys a discount on the gas that is allocated to it, given its investment in the required natural gas infrastructure. The later project, Mnazi Bay, was largely stranded until the construction of the Mnazi Bay–Dar es Salaam pipeline. The recent discovery of important off-shore gas reserves by international oil and gas companies has led to the proposal of an LNG-export facility. New legislation in response to the gas finds requires that part of the off-shore gas reserves be dedicated to the domestic market. The discoveries have also led to greater interest in the use of natural gas, with plans being made to expand the existing natural gas distribution network and pilot projects to promote gas use in transportation. However, developments in the international gas market show that oversupply is expected from 2016 onwards, due to softening Asian demand and the completion of multiple export projects commissioned earlier. Therefore, the development of Tanzania's offshore resources is expected to be delayed.

In 2012, the Ministry of Energy and Minerals (MEM) made projections for unconstrained electricity consumption for the period 2010 to 2035, forecasting a five-fold increase in per capita electricity consumption by 2035. The investment required in generation and transmission to increase installed power generation capacity and to increase the overall electrification rate is expected to be more than $40 billion – almost as much as Tanzania's GDP ($49 billion in 2014). Investment in Tanzania's power sector could be channelled from a number sources: the Tanzanian public, international financial institutions and donors, domestic and foreign private investors, or from commercial banks.

Investment arrangements that exist in the sector tap into the sources of funds differently, with varying types of constraints, sharing of risks, costs, and benefits.

In the power sector, five vehicles for investment exist: TANESCO, IPPs, EPPs, SPPs, and PPPs. Each vehicle has a different set of institutional arrangements which differ in the sources of funds that they access, the motivation driving investments, and the mechanisms through which investments are remunerated and risks are shared. Historically, TANESCO was the vehicle through which investments were made before the 2000s. From 2000–10, significant capacity of IPP-channelled investment came online, and since 2010 EPPs have been the source of additional (and temporary) generation capacity, along with a small amount of SPP-backed generation capacity. TANESCO has continued to be a channel for new generation investment since 2000.

Although direct investment by TANESCO is only one of the five investment vehicles, the other four are all deeply dependent on the state utility. This is because, given the existing structure of the Tanzanian power structure, TANESCO is either the only power off-taker allowed (for IPPs, EPPs, and PPPs) or the most important power off-taker (SPPs). Consequently, all power generation projects not procured directly through TANESCO still need to sign Power Purchase Agreements (PPAs) with it. TANESCO's financial health as well as its ability to structure and implement adequate PPAs are therefore critical to power generation investment in Tanzania.

Experiences in channelling private equity and commercial loans via IPPs and EPPs have had mixed outcomes: the lack of due diligence during procurement and the negotiation of the PPA often led to long and controversial legal disputes that incurred significant indirect costs, as well as blemished the public perception of private investment in Tanzania. The regulatory framework that Tanzania has set up for SPPs has attracted international accolades, but the generation projects thus far procured have been limited in number, due to the limited equity of domestic investors. So far, PPPs have not yet materialized, but they have the possibility of leveraging Tanzania's newly found gas reserves into strategic, collaborative investments with China and thus becoming the most important of the five investment vehicles.

Funds collected from Tanzanian ratepayers, taxpayers, international financial institutions and donors, and commercial banks flow into TANESCO. Unless earmarked for specific projects by sponsors, the funds collected typically go to pay for the utility's own operating expenses (including PPA payments) and loan repayments before they are directed toward investment. Since 2012, prevailing poor hydrology has led to the use of emergency power plants and extensive use of its own thermal generation plants, which severely stressed TANESCO's cash flow and is threatening its ability to deliver planed investment (and to fulfill its role as the counterparty to many PPAs).

From 2011 to 2013, accumulated losses within TANESCO's balance sheet almost doubled (from 800 to 1,450 billion TZS), having been relatively stable during 2007–11. By 2013, 80 per cent of the company's total assets were financed by liabilities (borrowings, trade, and trade payables), given that equity has not grown significantly and is devaluated by the mounting accumulated losses. Furthermore, TANESCO's liquidity ratio has gradually worsened since 2009. This indicates the company's mounting inability to pay off its creditors and its likelihood of default. Evidence shows that inadequate revenue collection is not a cause, thus suggesting insufficient structural revenue.

For the period 2007 to 2011, TANESCO's operating income was roughly in line with its operating expenses, but in 2012 and 2013 it reported significant net operating losses. The greatest cause of the losses can be tracked to significant increases in the purchased electricity component of its cost of sales. This is consistent with the evolution of hydro generating capacity available, subject to hydrological uncertainty (good hydrology in 2008–10, bad hydrology in 2011–13). The increase in revenue collected from different categories of customers has not matched the increase in cost of sales.

The continuous depreciation of the Tanzanian shilling has also had an adverse impact on the financial sustainability of TANESCO and its ability to make reliable payments towards PPAs. PPAs with IPPs and EPPs are usually denominated in US dollars, while TANESCO collects power tariffs denominated in Tanzanian shillings. Therefore, depreciation of the shilling against the dollar results in a funding gap between TANESCO's payment obligations and its revenues. It is estimated that currency depreciation might have contributed to about 20 per cent of increase in the costs of purchased electricity.

The expansion strategy proposed in the Power System Master Plan 2012 requires important investment to be made in power generation. It should also be acknowledged that, given the important role that natural gas plays in power generation expansion, corresponding investment is also needed in the natural gas sector. The production capacity for the near-shore resources needs to be doubled to match the planned natural gas consumption level. Also, off-shore resources need to be developed within 15–20 years, since the near-shore reserve will only be able to support planned consumption by power generators (not counting potential gas consumption in other sectors) for 17 years. In the short term, this requires TANESCO to improve its payment record for its existing gas-supply contracts to encourage further development of near-shore reserves. In the long term, this requires the government to carefully monitor the effect of its PSA terms and the international gas market on its IOC partners' willingness to invest in off-shore production.

Cost-reflective electricity tariff?

Under the current regulatory regime, it is the duty of the Energy and Water Utility Regulatory Authority (EWURA) to scrutinize all expenses incurred by TANESCO, safeguarding the interests of ratepayers and deciding which costs are to be recovered via the regulated tariff and governmental contribution and which costs are to be borne by TANESCO through cost savings. In this section, the governing principles for electricity tariff setting and common approaches in practice are introduced, followed by a description of the tariff setting methodology used by EWURA during its most recent tariff review in 2013. The Tanzanian approach is then evaluated against the rate design principles that it upholds in local legislation.

The setting of electricity tariffs by the regulator is necessary for the network segments in countries with liberalized power sectors and for all segments in countries with vertically integrated utilities. Tariff schedules need to answer to several governing principles whenever possible. Laws, directives, and regulations of countries commonly cite the following fundamental principles: economic sustainability, economic efficiency, equity, transparency, additivity, simplicity, stability, and consistency.

Among these ratemaking principles, equity, also referred to as 'the fairness principle', has the most ambiguous definition and is interpreted differently in different countries. It is impossible to fully meet all the above principles simultaneously. This is sometimes due to the lack of know-how, but it is more often due to inherent conflicts among these principles. Tariff setting methodology, which promotes the principle of economic efficiency, may clash with the principles of sufficiency, equity, or simplicity. Therefore, it should be kept in mind that the choice of any tariff setting methodology requires the decision makers to make an informed compromise, reaching a balance among all the principles discussed.

Any methodology for determining electricity tariffs can be divided into two steps, to which the different principles apply to differing extents:

1. Calculation of allowed revenues to be recovered;
2. Definition of a tariff structure and allocation of allowed costs to the tariff structure.

For example, the determination of the allowable volume of regulated revenues mainly needs to be weighed between economic sufficiency (ensuring the company's medium and long-term viability) and economic efficiency (ensuring that resources have been allocated efficiently in the company's operations). On the other hand, the design of the tariff structure and the allocation of allowed revenues using this structure need to balance equity, efficiency (providing the end-users with price signals that motivate efficient use of electricity), and sufficiency (ensuring that receipts from tariffs concur with the volume of allowed revenues).

There are two common ways for regulators to determine what revenue recovery should be allowed through the electricity tariff: the traditional method, known as cost-of-service or rate-of-return regulation, and an extension of it, known as the incentive-based regulation. The two differ mainly in the frequency of tariff reviews and how tariffs are set for the intervening years between reviews.

In cost-of-service regulation, the allowed regulated revenues are traditionally determined by identifying total costs of the company based on submitted accounting information for the previous regulatory period. At each tariff review, the regulator constructs the total cost of the company based on the summation of operation and maintenance costs, depreciation cost, return on regulatory asset base, and taxes. The regulator also subtracts additional revenues of the company from the total cost.

The operating and maintenance costs include the cost of fuel, material and replacement parts, energy purchases, supervision, personnel, and overhead. The allowed operating and maintenance costs might not represent total incurred costs, since not all of them are necessarily considered prudently incurred. In practice, the determination of allowed costs may involve the use of detailed analyses of each cost item and engineering or econometric models that allow benchmarking of utility companies against each other. The allowed rate of return is commonly calculated as the weighted average cost of capital (WACC). The rate base, a measure of the value of the company's investment, is its net fixed assets (fixed assets less the cumulative depreciation) plus current assets (fuel and other inventories, research and development expenses, and current asset requirements). From year to year, it is increased by capital investment and decreased by depreciation. Due to information asymmetry, the actual rate of return resulting from the allowed revenues might be above or below the true cost of capital, leading to overinvestment (when the rate of return is higher than true WACC) or underinvestment (when the rate of return is lower than true WACC).

In the incentive-based regulation, the determination of costs can be based directly on actual expenditure for the past accounting period (*ex post*), or be based on forecast of expenditure informed by historical information (*ex ante*). It is possible to affect the incentives of the regulated company through the choice of sources of cost information. For example, the regulator can set the allowed revenue of the company as the weighted average of *ex ante* and *ex post* costs using the following formula:

$$R_{allowed} = (1-b)C_{ex-ante} + bC_{ex-post}$$

In this formula, R is the allowed revenue, C is the cost (historical or projected), and b is the power of incentive. When the value of the coefficient b approaches 1, the company is allowed to recover all the costs incurred and has a low incentive to operate efficiently, since savings will not result in additional revenues. This is the case with cost-of-service regulation with annual or frequent reviews. When the value of the coefficient b approaches 0, the company is incentivized to cut costs in order to maximize profits, by harvesting the difference between the *ex ante* allowed revenues and actual costs, the most extreme case being a tariff freeze. By increasing the period between price reviews, cost-of-service regulation achieves a lower b coefficient, because the *ex post* assessment of allowed cost is maintained so that it becomes an *ex ante* assessment for the years further away from the tariff review.

Compared to traditional cost-of-service regulation, incentive-based regulation allows a company to receive more revenue during a regulatory period, but passes on the savings achieved by the companies to customers in the following regulatory period through the tariff review. If the tariff is frozen (an extreme form of incentive-based regulation) and adjustment toward *ex post* does not occur, then the total revenues received by the company may be excessively high, so customers are overcharged, or excessively low, so the sustainability of the company is threatened. Therefore, an intermediate value for the coefficient b is preferable. In practice, the period between tariff reviews is typically four to five years. The process for the tariff review is similar to the process described for the cost-of-service regulation.

Two basic schemes for incentive-based regulation exist: price cap and revenue cap. When tariff reviews are far apart, it is important to take into consideration the effect of inflation and events beyond the control of the utility, such as fuel price increases, and incorporate them into the price or revenue cap. A productivity factor is also used to account for increases in productivity (hence an annual decrease in price/revenue).

Once the volume of allowed revenues is determined, it is still necessary to perform the second step of the rate-setting methodology: deciding on the structure that the tariff should adopt (seldom changed upon tariff review, once decided) and the costs to be allocated to each element in the structure. The regulator may choose to allow the company flexibility to design its end-consumer tariffs, based on its allowed revenues, or to design the end-user tariff itself to prevent cost shifting among consumer classes.

The structure of the tariff is supposed to be a simplified representation of the cost structure for providing electricity. The exact costs of providing for each individual consumer at each moment in time are all different, but in practice tariff structure typically differentiates end-users in limited ways due to metering/billing limitations and the necessity to remain comprehensible to the consumers. Possible categorization of end-users can be done by the voltage level of the connection, by geographic area, by season, by blocks of hours, or by sector. For each category of end-users, the tariff can contain an element based on the maximum capacity contracted/installed (per kW), an element based on the energy consumed (per kWh), and a fixed charge (per connection). This is because capacity requirement, energy consumption, and number of customers are the three key cost drivers.

The two dominant approaches in allocating costs to an accepted tariff structure are the accounting approach and the marginal cost approach. These two methods each have their advantages and disadvantages. The direct allocation of allowable costs in the accounting approach, which averages cost components over different consumer categories, provides end-users with cost signals largely based on historical costs. This signal implies that the future costs of providing electricity will be as cheap or as expensive as in the past, potentially leading to over-consumption or under-consumption of electricity, infringing the principle of economic efficiency. But, this approach is relatively simple to understand and to use, and the regulated company can be sure that all allowable regulated revenues are recovered. On the other hand, if prices were set equal to the strict long-run marginal cost (LRMC), then customers would be informed of the marginal cost of their electricity consumption and make their decisions correspondingly: lowering their consumption if the LRMC is high and increasing it if the LRMC is low. However, the tariff revenue collected based on LRMC is likely to be different from the actual costs the utility incurred in providing electricity: a surplus is collected when the LRMC is higher than the current average cost, such as in the case that incremental consumption will require the use of more expensive generation unit, and a deficit is experienced when the LRMC is lower than the current average cost, such as in the case that incremental consumption will allow economies of scale given an existing generator is not fully utilized. The mismatch of revenue collected and cost incurred infringes the principle of economic sufficiency, which then requires revenue conciliation. This could compromise the efficiency of the LRMC tariff, if not executed carefully. In other words, the marginal cost approach is a future-oriented approach that provides ratepayers with cost information about the future, whereas the average cost approach is based on historical data, thus provides ratepayers with cost information about the past. Applying the marginal cost approach will lead to a tariff allocation process that is more complex, with revenue reconciliation sometimes required so that the revenues collected based on future-oriented costs match the utility's historically incurred costs. However, since the customers are made aware of the implication of their consumption choices, it is theoretically more conducive to efficient use of electricity.

At the time of writing, remuneration for the electric power industry in Tanzania is recovered via a multi-year integral tariff proposed by TANESCO and approved by EWURA, to be reviewed at least once every three years. This is equivalent to the price cap variety of incentive-based regulation with a standard regulatory lag. The integral tariff does not distinguish between the origin of costs that need to be recovered into functional segments such as generation, transmission, and distribution. This is a feature which reflects the current structure (not yet unbundled) of the power industry in Tanzania.

Since its establishment in 2006, EWURA has already undertaken five rounds of tariff reviews. The paper describes the rate-setting principles upheld by Tanzanian legislation and the integral tariff determination process in use during the latest review. A tariff review is planned for the year of writing

(2016), but it has not taken place by the time the authors completed research for this paper, therefore it is not included as part of this study.

The questions that need to be answered while scrutinizing the integral tariff in place are therefore focused on the ratemaking principles that are upheld in Section 23.2 of the 2008 Electricity Act. The key questions are: whether economic efficiency, economic sufficiency, and equity in revenue determination and tariff allocation are observed; and whether tariff allocation satisfies the principle of stability over time.

The revenue requirement as per TANESCO's 2013 tariff application is compared to the AF-Mercados 2012 Cost of Service Study (CoSS), the only benchmark study available, as an approximate evaluation of its efficiency. Then, the revenue approved by EWURA is compared with the original TANESCO proposal to gauge sufficiency. The way in which government/development grants are treated in the calculation of revenue requirement is evaluated for equity, with the tariff structure proposed in its tariff application and the EWURA approved tariff then evaluated (independently of the evaluation of revenue determination) in terms of efficiency, sufficiency, equity, and stability.

Before providing answers to aforementioned questions about compatibility with rate making principles, it is worth highlighting some elements of the process of tariff setting in Tanzania. To begin, the formula used by TANESCO to calculate its revenue requirement in its 2013 tariff review application is different from the one specified by EWURA in its 2009 guidelines. The two formulas both have the pass-through of operating and maintenance costs, but they have different ways of accounting for and rewarding investment in the power sector.

In EWURA's original formula, the underlying logic is that the equity and liability owners of the utility company – in TANESCO's case, the government and development banks – provide *up-front* funds for the planned additions to an *existing* asset base. In this way, the updated rate base and the recognized WACC inform the calculation of revenue requirement, based on which the company collects a return upon the capital invested. The annual revenue collected, in principle, other than covering operating expenditure, is enough to cover interest repayments and dividend payments. After that, the utility executive can make decisions to make further investment on behalf of the shareholders.

In TANESCO's formula the rate base is *absent*, but there is a depreciation term (supposedly calculated based on a certain book value of all existing fixed assets, a stand-in for the rate base but not shown). Consequently, a return upon the rate base cannot be determined, so loan repayment and investment are levied directly via the revenue requirement. Some type of equivalence could be drawn between the two formulas, in the case that some conditions are met (see box below). However, this inconsistency in tariff setting methodology needlessly complicates the way revenue requirement items are to be analyzed. Therefore, either EWURA or TANESCO needs to revise their tariff setting guidelines/application to consolidate the formula to be used.

Investment funds directly levied from current ratepayers could be an alternative form of financing. One condition exists: the assets financed with the levy should not be included in the rate base awarded with a rate of return, should that become the method through which future revenue requirement is calculated. In other words: if the current ratepayers were to finance the investments directly, then they (and future ratepayers) should not have to pay returns to the capital invested in those assets to TANESCO, who will be holding these assets.

As for the loan repayment levied, it could be considered to be the rate of return charged for the debt portion of the asset base. Therefore, if the sum levied is in line with the known cost of debt, then it could be justified as a reasonable cost to be passed on to the rate payers, with the condition that the debt portion of the rate base is not receiving any other form of compensation.

Secondly, the CoSS performed by AF-Mercados presents estimated cost of service for TANESCO in terms of different industry segments (generation, transmission, and distribution). However, TANESCO did not report its revenue requirements disaggregated by segments. This makes it difficult to conduct direct comparison between the two to assess cost efficiency, making independent verification difficult. Therefore, in the future, as TANESCO progresses toward the first milestone in structural reform (accounting unbundling of generation, transmission, and distribution), the revenue requirement that it supplies in its tariff review applications should be correspondingly disaggregated.

Lastly, in the tariff order published by EWURA in response to the TANESCO 2013 application, the regulator has listed the various tariff schedules approved, but not the approved revenue requirement upon which they are based. Therefore, the regulator's assessment of the appropriateness of the TANESCO tariff review application is not in the public domain. Given that the tariff application is already in the public domain, publication of the approved revenue requirement and its breakdown will increase the transparency of the rate-setting process.

We can now turn to the compatibility of current electricity tariffs with rate making principles. Our analysis of this issue revealed some useful information.

With regard to economic efficiency in revenue determination (that is, the question of whether allowed revenues, to be recovered from ratepayers, represent efficient use of resources by TANESCO), our analysis shows that the computation of revenue requirement is based on the *ex ante* forecast of the cost elements rather than an *ex post* evaluation of historically incurred costs. In principle, this incentivizes TANESCO to provide regulated services at costs lower than those approved.

We also found that the generation-related costs are highly sensitive to generator availability assumptions. The availability of different types of generation capacity is a parameter that has high sensitivity in forecast outcomes, given that the supply stack of installed capacity in Tanzania has a three-tier structure: very low variable cost hydro forms the first tranche, followed by gas generation capacity with medium variable cost, and liquid-fuel fired generation with high variable cost. The availability of hydro generation is dependent on hydrology, while the availability of gas generation is dependent on gas availability – two factors which are beyond the control of TANESCO. This means that any generation revenue requirement which does not explicitly address these two exogenous uncertainties will have a high margin for error. This increases the difficulty of *ex ante* revenue requirement determination, which is the currently adopted method. For the same reason (tier-shaped supply stack), a small increase in incremental peak demand might lead to disproportionally higher marginal generation cost. Therefore, it is hard to assess the efficiency of generation costs unless availability and peak demand assumptions are agreed upon by the utility and the regulator.

With regard to economic efficiency in tariff allocation, we have analysed whether the tariff charged incentivizes consumers to use electricity efficiently. Within the approved tariff design, the capacity charge incentivizes larger (T2 and T3 tariff categories) consumers to use contracted capacity more evenly and contract only as much as needed. The increasing block design for the energy charge of the customer class with the smallest consumption (D1) incentivizes them to switch to the general class (T1) once monthly consumption exceeds 400 kWh. All users consuming more than 200 kWh are incentivized to contract power at the highest voltage level possible, given the lower average cost of electricity charged.

Given the Tanzanian power system's high sensitivity to peak demand, it should be investigated whether additional measures such as time-of-use tariff could bring important system savings by avoiding the use of expensive oil-fired generation units (EPPs). In the long term, EWURA might consider transitioning from the accounting approach of cost allocation to the marginal cost approach, so that the use of electricity by Tanzanian ratepayers is based on the knowledge of the amount of future resources used to provide it.

Economic sufficiency in revenue determination analyzes the question of whether the allowed revenues to be recovered are sufficient to cover the operating expenditures of the licensees, including a reasonable return for the capital invested. Furthermore, we investigated if the totality of tariff charged corresponds to the allowed revenues (additivity).

We noticed that because EWURA published the approved tariff levels but not the approved revenue requirement from which they were derived, it is not possible to ascertain the regulator's position toward specific items in TANESCO's proposed revenue requirement.

Our analysis also indicates that the tariff levels proposed by TANESCO for year *t* is additive and sufficient to recover all revenue requirements (including operating expenses, loan repayment, and self-funded investment) proposed for the year *t-1*. The tariff approved by EWURA for year *t* is just sufficient to recover operating expenses forecasted for the year *t-1*. This is consistent with the trend exhibited by TANESCO's overall expenses and tariff-based revenue during 2006–10. Comparison of TANESCO's revenue requirement with the AF-Mercados CoSS shows that the amount of transmission and distribution network investment planned by TANESCO was significantly lower than expected. Possibly, part of that investment is shouldered by REA which is funding much of the distribution network expansion in rural areas. However, it could also be a sign that the (historical and expected) approved revenue requirement is not high enough to sustain TANESCO's own investments.

For the principle of equity in revenue determination, we analysed the way grants from the government and development partners were treated in the computation of the revenue requirement. Our results confirm that when calculating its revenue requirement, TANESCO deducts its other sources of revenue, including government revenue grants, from the revenue requirement. This is consistent with the legislated principle that the costs covered by such revenue shall not be reflected in the revenue requirement. The EWURA-approved revenue requirement formula should be adjusted to incorporate such revenues.

In relation to the principle of equity with respect to tariff allocation, we examined whether there are cases which customer classes are charged more than the costs they impose upon TANESCO (cross-subsidization) and how such cases are justified.

We found that the extent of cross-subsidization in the case of the lifeline rate is limited. D1 customers who benefit from the subsidized lifeline rate consume 2.3 per cent of all energy supplied and are responsible for 0.9 per cent of customer bills. The overall effect of the lifeline subsidy is small, and it is not formally justified in TANESCO or EWURA's documents. Assuming that costs are to be allocated based on contribution to total demand, then the latest approved tariffs might have attributed more costs to be borne by T1 customers and less to be borne by T3-MV customers. It is hypothesized that this might be a decision on the part of the regulator, after consultation with representatives of electricity consumers, to cross-subsidize the industrial customers (T3-MV class).

Finally, for the stability of tariff allocation we explored whether approved tariffs are consistent over time. Our analysis demonstrates that the approved tariff has been steadily increasing (especially the energy component of the tariff) since 2006. EWURA has consistently approved tariffs which are lower than the ones that TANESCO has applied for, and the average increase has never been higher than 40 per cent. When distinguished by customer class, the energy charges of D1 <50/75 kWh customers and of T3-MV customers have been increasing more slowly than those of other classes of customers. This observation is consistent with the cross-subsidization of D1 lifeline customers and the hypothesized cross-subsidization of T3-MV customers.

The approved mechanism to adjust tariffs for changes in fuel costs, foreign currency exchange rates, and inflation, meant to reflect changes in costs that are beyond the utility's control, is expected to increase the volatility of the approved tariff over time, but its implementation is unlikely to be automatic in the near future. The regulator has shown that it assesses the likely impact of the tariff adjustment before approving/disapproving adjustment according to the formula. Effectively, they become more frequent tariff reviews with smaller scope (only a component of the tariff is reviewed). This will decrease the regulatory lag in Tanzania's tariff setting process and, in theory, decrease the incentive for the regulated utility to seek efficiency savings. However, before a full oil-to-gas transition in the power sector is complete, fuel costs – which are largely outside of the control of the utility (volatile oil prices and uncertain hydrology) – should be adjusted so that not all risks are borne by the utility.

International Experiences

In order to shed light on the path forward for Tanzania, the experiences of Bangladesh and Côte d'Ivoire (Ivory Coast) in the co-development of natural gas and electricity are discussed. These countries were chosen based on the relative use of natural gas in power generation in their energy system and their level of electricity consumption.

The case study of Bangladesh is a particularly valuable one for Tanzania, given the many similarities in the recent development of their power sectors. Moreover, Bangladesh's power sector has developed to the point that Tanzania wishes to reach, namely: vertical unbundling between generation, transmission, and distribution; horizontal unbundling within generation and distribution; and the establishment of separate wholesale, transmission, and retail tariffs.

The case study reveals that the availability of a domestic fuel for power generation and a low tariff for its use in the power sector do not guarantee unconstrained growth of the power sector's ability to meet demand. Instead, the same problem encountered in the power sector – that is, demand that is growing at rate that cannot be sustained by local conditions – could be replicated in the gas sector. When the tariff of natural gas, a depletable resource that is extracted, is set to recover strictly necessary cost for extraction instead of the opportunity cost of its use, high and inefficient demand for gas is likely to develop in all sectors of the economy. This becomes problematic when the country in question does not have developed technical and financial capacity to develop additional gas resources or alternative energy sources, bringing development to a halt. The case study also illustrates how the contracting of emergency power, perceived as a temporary solution, consumed project management capacity and cash flow from the public utility, potentially weakening the power sector's ability to develop more permanent forms of power generation capacity. Finally, decentralized rural electrification through PBS (Palli Bidyut Samity, or Rural Electric Societies) is very effective, but it also contributes to the rapid build-up of demand and stresses the fragile power system infrastructure.

Côte d'Ivoire has many similarities to Tanzania, especially in the development timeline of its power and gas sectors. However, the nature of private sector presence, the growth of power demand, and the natural gas endowment of the two nations are very different.

The companies controlled by Bouygues, a French industrial group, include gas production, power production, and power retail. Their influence has been considered mostly positive, given that this quasi-vertical integration lowers the companies' operational risk, which could in turn increase the parent company's willingness to invest. The stagnant growth of power demand, partially attributed to civil unrest and to non-aggressive rural electrification efforts, has been transformed into a relative advantage for Côte d'Ivoire. The overcapacity available, procured on-time due to smooth IPP construction and commissioning, has been used for export to neighbouring countries, which bolstered Côte d'Ivoire's reputation as a regional powerhouse, further encouraging investment. As the country's power demand growth accelerates, it is in a relatively good position for attracting private investment. The Ivorian experience demonstrates the critical nature of timing; the pacing of supply growth relative to demand growth. Once supply (sourced at reasonable prices) is sufficient to cover existing demand with a comfortable margin, it becomes easier to procure future supply, changing the dynamics of power system planning from demand-pulled to supply-pushed. Although Côte d'Ivoire has significantly less natural gas resources than Tanzania, which might be unfavourable in the long-term for its gas-to-power projects, the current global LNG market is more favourable to the importer than the exporter, given the glut of LNG export project commissioned/to be commissioned within a short period of time. While Tanzania's plans for off-shore natural gas development might be delayed, Côte d'Ivoire might be able to enjoy more competitive LNG imports than would otherwise be the case. That said, the Ivorian model also exhibits some major weaknesses: the stagnant electrification rate since 2000 is believed to have been caused by the lack of institutions dedicated to the cause of rural electrification.

Also, high technical and commercial losses (26 per cent) have been experienced despite management of the whole sector by a single private company, since that company is not incentivized/allowed to invest in power sector infrastructure.

Conclusions

In order to fulfill its aspiration to become a middle-income country, Tanzania is working on improving infrastructure and service delivery in electricity provision, where $40 billion investment is needed in the sector to meet rising demand and widening electrification efforts from 2013 to 2035.

This paper considers the institutional arrangements for investment in Tanzania's power sector and surveys the track record (and possible bottlenecks) in funnelling investment to the sector, with special attention given to the gas sector, given the power sector's planned reliance upon natural gas as a generation fuel. The paper finds that the financial health of TANESCO is central to all investment vehicles, since it is either directly responsible for investment, or indirectly, as the counter party to the variety of PPAs available with IPPs, EPPs, SPPs, or PPPs. During 2011–13, the financial position of TANESCO was negatively impacted by the increased of its electricity purchases, while the regulated tariff that it charges has not changed. The cost increase is partially attributable to non-favourable hydrology and partially attributable to the depreciation of Tanzanian shilling against the US dollar, in which PPAs are denominated.

Detailed study of the tariff setting methodology in place in Tanzania, as evidenced through its latest tariff review, and evaluation of the ratemaking principles used in the tariff approved in 2013 reveals that the core tension within Tanzania's tariff setting methodology is the trade-off between efficiency, sufficiency, and stability principles. The *ex ante* assessment of TANESCO's revenue requirement, a typical incentive-based price cap regulation, is theoretically efficient but not robust: TANESCO's costs of service are subject to important external uncertainties like hydrology, currency depreciation, and global fuel prices. In order to take revenue sufficiency into account, the regulator needs to periodically adjust tariffs based on *ex post* fuel costs and inflation rates. This diminishes the regulator's ability to maintain tariff stability, which might impact certain classes of customers more than others (lifeline rate customers and domestic industries). The experiences of other nations, namely Bangladesh and Côte d'Ivoire, reveal a potential challenge with regard to power and gas co-development: if non-cost reflective gas tariffs are applied as a regulatory decision, then high gas demand that results from that cannot be indefinitely sustained, since investment in gas supply will not follow suite. The case study of Côte d'Ivoire also reveals a less obvious opportunity: periods of low electricity demand can be leveraged positively through electricity exports, which can positively influence investor interest.

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