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How is the distribution sector in low-access countries attracting private sector participation and capital?

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How is the distribution sector in low-access countries attracting private sector participation and capital?

The provision of reliable, affordable and adequate electricity supply forms the bedrock of economic growth and social development. It strongly influences the competitiveness of local industry, supports effective delivery of public services such as health and education, and catalyses economy-wide activities across key sectors such as agriculture. Challenges facing the power sector in developing economies are well-documented: lack of sufficient low-cost wholesale power supply, high technical and commercial losses, lack of investment in generation and distribution infrastructure and high cost of expanding access to unconnected consumers, among others.

Distribution companies (discos) are a key player in the power sector. Positioned in the centre of the generators and consumers, discos play a critical role in the delivery of reliable, affordable and adequate electricity supply for all consumers. They are also the weakest link in the power sectors of developing countries faced with large populations without electricity access (hereafter referred to as “low-access countries”).

Discos in majority low-access countries are faced with a deteriorating financing situation as a result of a combination of factors: limited cost-recovery due to tariff structures and high cost of wholesale power supply, along with large technical and commercial losses. This has resulted in under-investments in the distribution segment, including infrastructure and network expansion, affecting accessibility, quality and reliability of supply. In turn, commercial and industrial consumers that traditionally have been the important sources of revenue for discos are increasingly investing in captive generation based on diesel and renewable energy.

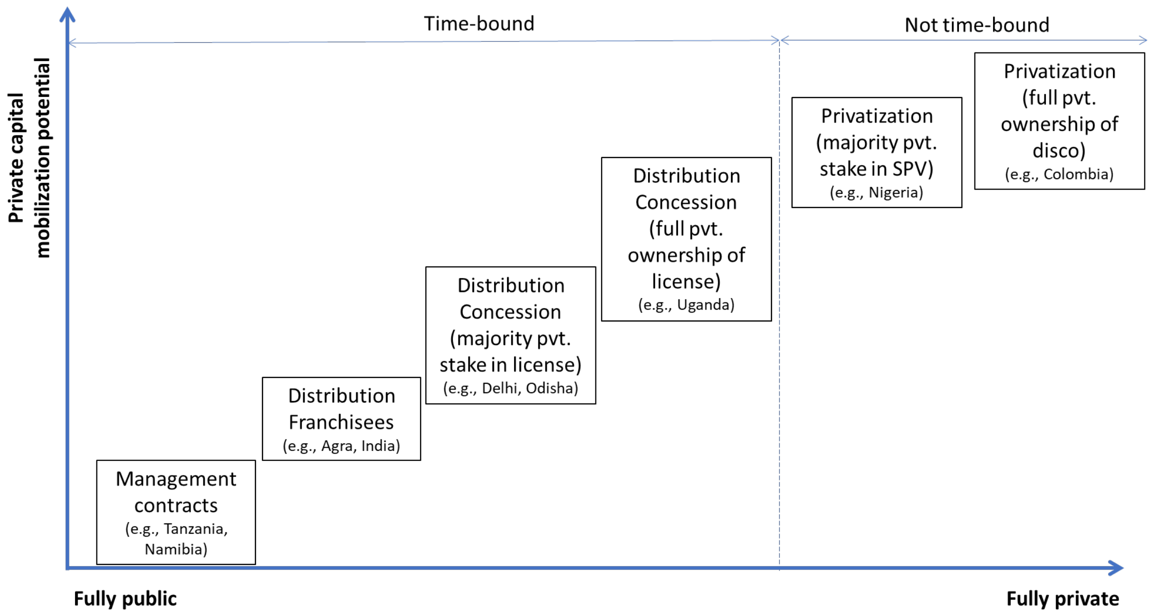
Addressing the structural challenges and long-term financial-sustainability concerns of discos will be crucial for mobilising investments towards the urgently needed infrastructure in distribution, as well as meeting the universal electricity access objectives. With a heavy involvement of the state in the ownership and management of discos, greater private sector participation in distribution is seen as an important catalyst for improving internal management and operation with a view to improve operational viability. Importantly, it is also a means to attract the substantial levels of investments needed for the development and strengthening of infrastructure to improve quality and reliability of service and add new connections.

HOW IS THE DISTRIBUTION SECTOR IN LOW-ACCESS COUNTRIES ATTRACTING PRIVATE SECTOR PARTICIPATION AND CAPITAL?

The function of the distribution sector in developing countries is steeped in deep political-economy considerations, especially for pricing and enforcement (Scott and Seth, 2013[1]). Therefore, tailored models for private sector participation have been implemented in developing countries with varying objectives and results. While privatization efforts in the generation segment have been largely successful with the introduction of Independent Power Producers, the distribution sector has tried a diversity of approaches, which often mesh with continued public sector ownership, with mixed results (Ghanadan and Eberhard, 2007[2]).

Through examples, this technical note discusses the experiences involving different models of private sector participation in the distribution sector. As illustrated in Figure 1, the models are assessed from the perspective of meeting the two pre-requisites for strengthening the distribution sector in low-access countries: nature and extent of private sector involvement and the potential for mobilising substantial private capital.

Figure 1 Different modes of privatisation of distribution sector in developing countries



Private sector involvement in the distribution sector can be designed to be time-bound or indefinite. Time-bound privatization measures are for a specific period of time after which the operational and economic rights of distribution reverts back to the government/public sector control. Examples of such measures include:

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[1] Scott, A. and Seth, P. (2013), The political economy of electricity distribution in developing countries: A review of the literature, Overseas Development Institute, www.odi.org/sites/odi.org.uk/files/odi-assets/publications-opinion-files/8332.pdf

[2] Ghanadan and Eberhard, A. (2007), …

- ***Management contracts*** wherein private sector involvement is short-term (5-10 years) and largely limited to improving internal management and reducing AT&C losses through higher collections and tariff reforms. The large-scale mobilisation of private capital is often not the focus of such measures.
- ***Distribution franchisees*** are usually short- and medium-term (5-15 year) agreements between existing distribution licensees and private entities to carry out activities related to supply, billing and collection, customer engagement, reduce technical losses and undertake capital expenditures needed to meet performance objectives.
- ***Distribution concessions*** wherein an entity which is majority or completely privately-owned is provided a long-term (20-25 year) distribution license to service a certain territory. In such cases, the entity has full operational rights over the duration of the concession while the extent of economic rights vary depending on whether government retains partial ownership in the entity. Here, the objective is usually to mobilise private capital for investments into the infrastructure and operations.

Indefinite privatization measures essentially involve transfer of operational and economic rights of distribution to the private sector with the intention that at no time does the control revert back to the government/public sector. The entity taking over the distribution licensee under such a privatization model may either be entirely owned by the private sector (*e.g.,* as is the case in Colombia) or majority-owned (as is the case in Nigeria).

The technical note will discuss the different models in-depth discussing their key design elements, outcomes and lessons learnt. Finally, the note will present key learnings for the implementation of the Integrated Distributed Framework.

I. MANAGEMENT CONTRACTS

Management Contracts (MCs) have been primarily used as a short-term tool to engage the private sector to oversee all, or part, of distribution company operation with the objective of improving financial and/or technical performance without a substantial increase in the capital raised and invested in the system. The duration of such contracts can be as low as two years. A common context where such contracts have been used is where AT&C losses are extremely high and substantial revenue can be unlocked through reductions in the losses with limited additional capital investments.

Such contracts are sometimes considered as a step towards privatization by improving the fundamentals of the distribution sector and, thereby making it more attractive for longer-term private sector participation (ECA, 2015[3]). A number of countries in sub-Saharan Africa have introduced management contracts in electricity distribution, including Tanzania, Namibia, Ethiopia, Congo and Kenya, as well as in India.

Management contracts traditionally are designed around very specific technical and commercial performance criteria. In Tanzania's case, the contract was structured into two phases with differing quantifiable objectives: Phase I (financial turnaround) mainly by increasing revenues; and Phase II (technical turnaround) mainly by reinvesting revenue gains into reducing technical losses and improving system reliability.

Unlike the Tanzania's case, the MC in Namibia's case was not highly prescriptive both in terms of governance or performance measurement. It did not outline methods for evaluating performance relative to a few specified indicators, therefore providing Northern Electric (NE), the MC holder, flexibility to develop its own methods and define its own terms for success[4]. While such an approach is beneficial when interests of the parties are aligned, it can be challenging when they are not. One of the drawbacks noted was the lack of clarity in the contract on asset valuation after NE's license was not renewed. The MC had a limited electrification mandate. Yet, the MC company enforced a rural electrification levy to collect revenues to make the required investments to increase the rate of connections. The autonomy to implement tariff changes played a critical role in increasing the rate of new connections.

Compensation

The MC company is compensated through a fixed payment and performance-linked incentives that depend on the set objectives of the contract. In Tanzania's case, the MC company (NETGroup) is estimated to have received USD 18-19 million for the duration of the contract, of which USD 8.5 million were fixed retainer fees and the remainder in success fees. The success fee calculation methodology is elaborated in Annex 1. The contract was financed from utility revenues and donors (sida funds administered through the World Bank).

The financing of the management contract requires subsidy to ensure that the burden of fixed charges does not entirely rest on the government, which acts as an inhibiting factor. The management fees are often too costly and unable to bear the cost without adequate public financing. This was one of the reasons for the Government of Kenya to not renew the management contract with Manitoba Hydro despite several gains

[3] ECA (2015), Evidence and Gaps in Evidence in use of Management Contracts for Electricity Distribution and Supply, Economic Consulting Associates, https://assets.publishing.service.gov.uk/media/57a0896c40f0b652dd000202/EoD_HDYr3_66_December2015_Elect_Mang_Contracts.pdf

[4] http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/EconOneResearchInc_Northern_Electricity_Distribution.pdf

such as a near doubling of new consumer connection and reduced system losses from 19.6% to 17.6% in the first year (ECA, 2015).

Outcomes and challenges with meeting technical goals without capital investment

There is some evidence to suggest that MCs can bring about substantial changes to utility operations and generate positive commercial outcomes. In the TANESCO (Tanzania) case, monthly revenues increased from USD 10-12 million in 2001 to USD 16 million by mid-2004 and USD 22-24 million in 2005-06 (Ghanadan and Eberhard, 2007). This was a result of growing electricity sales (37% increase due to increasing consumers), increasing tariff (tariff growth and restructuring to reduce cross-subsidization) and improving collection (from 69% in 2001 to 85% in 2002; arrears of large industrial consumers were negotiated without disconnection). During the term of the six-year MC in Namibia, substantial improvements in collection rates and reliability of supply were recorded. Collection rates grew from under 50% to 99%

Technical objectives were largely not met due to limited capacity to make substantial capital investments in the infrastructure. In Tanzania's case, technical power losses were maintained at starting levels, around 22% in 2006, primarily due to insufficient investment infrastructure. Related, reliability of supply also did not improve. Levels of new electrical connections did not increase substantially, remaining steady at about 2,500 connections per month.

Beyond incentives, it is equally important to ensure that adequate public financing is available to bridge the investment gap to meet capital-intensive performance targets. Ideally, the subsidy needed to meet the capital requirements for reaching technical objectives should have been determined and covered through public financing.

The short-term nature of management contracts may be insufficient time for a complete turnaround of the utility and, therefore, should be part of a broader package of solutions to improve the operations, financial viability and investment-worthiness of utilities.

II. INPUT DISTRIBUTION FRANCHISE[5]

A distribution franchisee model involves a bilateral agreement between a distribution company (Disco), typically publicly owned, and a private sector entity, the franchisee. The regulator or the Government is not party to this agreement. Several different

[5] Our reference case example for this business model will be the distribution company supplying Agra and the surrounding area, where the concessionaire in Torrent Power. Several other successful IF exist in India.

models of franchisees exist depending on the level of responsibility undertaken by the franchisee. These could range from collection-based wherein the role of the franchisee is limited to billing, revenue collection and customer engagement, to input-based which involve franchisees also supply power, undertaking capital investments and committing to performance targets linked to AT&C losses and collection efficiency (REC, 2009[6]).

In this section, the "input distribution franchise" (IF)[7] model is discussed. Note that, regardless whether the incumbent power company signing the contract is vertically integrated or not, the concession only refers to the activities and assets corresponding to the distribution segment.

Per the agreement, the Disco outsources the management of the company – administration, operation and maintenance (AO&M), metering, revenue collection, customer attention, and minor investments to reinforce or improve reliability or quality – to the franchisee.

Any necessary major investments (e.g. a new substation, a major interconnection) are the responsibility of and are paid for by the distribution company.[8] The autonomy that the IF has to undertake capital expenditure varies from case to case. The Franchisee Agreement lays out a minimum capital investment plan by the licensee. Meanwhile, in some cases (e.g., Torrent Power in Bhiwandi and Agra in India) the IF is allowed to undertake capital expenditure if required for loss reduction and improved quality of supply without prior approval from licensee or regulator and bear all costs. In Nagpur, regulatory approval is required for capital expenditure. The franchisee in this particular case is compensated for the residual or depreciated value of the assets it has financed, at the end of the franchisee period when such assets are transferred to the licensee.

A key feature of the IF is that its remuneration is not based on any regulatory asset base (RAB). Therefore, the minor investments performed by the franchisee are ignored in the remuneration scheme in most cases where this approach has been followed. It is the responsibility of the franchisee to deliver the performance that has been agreed in the contract by making use of O&M actions, accompanied by whatever

[6] REC (2009), National Franchisee Training Program: Reference Book, https://recindia.nic.in/download/National%20Franchisee%20Training's%20Reading%20Material-English.pdf

[7] In addition to the input-based franchisee model, other franchisee models include input-plus-investment based (wherein specified investment is to be undertaken by the franchisee) and input-based franchisee-incremental revenue sharing (IBF-IRS). IBF-IRS is usually a short-term contract (~5 years) where input energy delivered to the IF without payment and the incremental revenue realised beyond the baseline is shared between the franchisee and the utility in the ratio as per the contract. This model was unsuccessfully applied in Odisha (More details in Annex 2).

[8] It would be interesting to look in detail into this governmental relationship and how it relates to the franchisee. Agra is a clear example of this.

minor investments are necessary, as considered best by the franchisee. The contract and the incentives in the remuneration scheme only relate to the achieved performance and not to how it has been attained. Any capital expenditure made by the IF must be fully recovered from the incremental revenues generated by the IF from reduction in inefficiencies and improved collection performance.

The franchisee pays an agreed price for the energy that is input into its network at prespecified connection points. It delivers electricity to the customers in the territory covered by the franchise subject to some performance requirements – time trajectory of total losses, and minimum number of hours of supply within specific time intervals; more advanced measures of reliability or the number of new connections could be included, but we have not found examples of it – and economic incentives – penalties or credits – associated to the actual performance observed.

The franchisee may engage with the customers in its assigned territory to reduce commercial losses, encourage uses of electricity that will increase economic growth as well as demand growth, and any other social and economic activities that may promote a good relationship between the company and its customers. The franchisee may reach out to any non-connected potential customers and encourage them to connect to the network (this is the case of Torrent Power in Agra). This is of particular interest for commercial and industrial customers, who often are voluntarily off-grid, when the supply is unreliable.

The franchisee collects and keeps the revenues from regulated tariffs that are established by the regulator. Therefore, the income of the franchisee is determined by the price paid by the purchase of the wholesale energy, the revenue collected via the regulated tariffs and the cost of the O&M and small investments that are necessary to meet the established performance targets. It is not based on any estimate of the efficiently incurred costs.

The IF is allocated in a competitive auction, where the winner is the company that bids the highest present value of the annual input rate that the Disco needs to supply. The input energy rates quoted by the franchisee shall be deemed to have taken into account the cost of finance and depreciation on account of these investments. In some cases, such as Bhiwandi and Ajmer in India, bidders have to base their bids for input energy rate based on a minimum reduction in distribution losses and improvement in collection efficiency by the end of the contract period.

At the end of the term of the franchise, the bilateral relationship just stops, since there is no pending economic transaction. The IF can be renewed. At no moment during the IF process that franchisee owns any asset of the Disco. The entire ownership remains at all times in the incumbent distribution company – typically public – hands.

III. DISTRIBUTION CONCESSIONS[9]

A Distribution Concession (DC) engages the private sector to mobilise investments in the distribution sector is usually long-term (20-25 year). Compared to management contracts, the level of private sector engagement increases under such concessions as they assume a greater risk in anticipation of a return. Strict concessions require the private lessor to operate, maintain, and expand the asset, and, at the end of the concession period, return the asset, with all improvements, to the owner, and receive a payment for the residual value of the investments made[10].

DC is a more complex regulatory and legal construct than the IF. The major difference with the IF is the need for substantial investments, therefore requiring additional regulations regarding the remuneration in order to reduce the risk of the concessionaire (of not having its investment and operation costs properly remunerated) and the risk of the consumer paying too much for the service (or too little, rendering the distribution activity insolvent). As in the case of the IF, regardless whether the incumbent power company is vertically integrated or not, the concession only refers to the activities and assets corresponding to the distribution segment.

The concessionaire is a company, which in general would be established as a special purpose vehicle (SPV), i.e. with several participating entities, just for the purpose of managing the concession, possibly with non-recourse. The ownership of the SPV may be structured in different ways. In the case of Uganda, for instance, the SPV is owned entirely by the private sector. Meanwhile, in Delhi or Odisha (India), the private sector owns a majority controlling stake in the SPV, while the remainder of the equity stake is held by the government. At the end of the concession all the assets are returned to the incumbent utility.

As with the IF, the SPV will take over the entire management of the distribution company. However, in this case all investments will be made entirely by the SPV, in line with an agreed capital expenditure plan and following approvals by the regulator and/or the ministry for any major investments.

The distribution assets will be split into two categories for regulatory and business model purposes: i) the new investments A made by the SPV during the duration of the

[9] The reference case for the DC business model will be the distribution company supplying a large fraction of the city of Delhi and that is managed by Tata Power Delhi DL. However, we shall mention frequently the case of Odisha, where Tata Power has been awarded a concession agreement for the supply of a large part (about one third) of the state which is predominantly rural.

[10] Hoseir et al. (2017) and Jacquot (2019) provide a comprehensive overview of the different types of concessions supported by country examples.

concession, and ii) the assets B that existed at the moment of awarding the concession.

In the case of a DC, the concession contract is signed between the SPV and some governmental entity, acting on behalf of the customers, and it will be supervised by the regulator or some ministerial department or public agency. It follows a description of the general characteristics of this kind of contract, illustrated by some examples.

Treatment of assets A.

The regulator computes the revenue requirement RRA to be paid to the SPV for the cost of service associated with the new investments. The RRA comprises capital costs CAPEXA and administrative, operation and management costs OPEXA.

Regarding CAPEXA, the regulator must follow the usual procedure to determine the regulatory asset base of the new investments (RABA), and the corresponding cost of capital to be paid every year to the SPV on this concept. The usual separate remuneration of debt and equity resulting in the WACC to be applied to the entire RABA would be followed. The return on equity might be established from the outset for the entire period (this is the case of the 20% of Umeme, or the 16% of Tata Power Delhi. Alternatively, it could be adapted to the capital market conditions <<is it the case of Odisha?>>. The cost of amortization of the assets will be computed on the basis of the economic lives of each one.[11]

Guaranteed return on equity incentivizes much-needed investment in distribution. In the decade between 2002 and 2013, Tata Power Delhi incurred capital expenditures of over INR 3000 crores (or USD 418 million at current rates) [12]. Meanwhile, Umeme in Uganda has invested over USD 600 million since 2005 in the distribution system (Umeme, 2019)[13]. Where other investment risks may be prevalent, de-risking measures have been introduced such as the setting up of an escrow fund to ensure payments from the government to the concessionaire and political risk insurance from MIGA as has been the case in Uganda (World Bank, 2015)[14].

One important issue is what assets the regulator considers that can be included in the RAB. For instance, in the concession contract of Tata Power in Odisha, investments

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[11] The actual composition of the capital of the company will consist of a mix of debt and equity, where debt may have return periods much shorter than the economic lives of the power systems assets. The SPV will have to find the way of providing a solution to this mismatch, by making use of additional financing instruments.

[12] Tata Power – DDL (), https://www.tatapower-ddl.com/Editor_UploadedDocuments/Content/FAQ's.pdf

[13] Umeme (2019), https://www.umeme.co.ug/umeme_api/wp-content/uploads/2019/07/UMEME_Power_Book_web.pdf

[14] World Bank (2015), http://documents.worldbank.org/curated/en/354661498163378835/pdf/116661-WP-P150241-PUBLIC-53p-Detailed-Case-Study-Uganda.pdf

in generation or storage, either on- or off-grid, that might be used to reinforce the end of long feeders where reliability and quality of service may be poor, will not be included in the RAB.[15]

The concession contract of Tata Power in Odisha establishes that the CAPEXA annuity will be updated every year to account for the new investments, while the annual value of OPEX is reviewed every three years. This incentivizes Tata Power to improve the efficiency of O&M, as well as gold plating (regulator permitting) its new investments.[16]

At the end of the concession period (20 or 25 years are typical values), if the concession is not renewed the residual value of the A assets must be paid to the owners of the SPV, which is terminated. The Government retains the full ownership of the distribution company.

Treatment of assets B.

Assets B, that existed at the time of awarding the concession, require administration and operation and maintenance. Therefore, CAPEXB must be included in the revenue requirement, as it is done with CAPEXA.

The issue to be addressed now is what to do with the capital cost associated with Assets B. First, it is to be expected that a rigorous accounting of the value of the existing distribution assets has not taken place, and therefore the value of CAPEXB is not known. Second, in most developing countries with access deficit, governments do not want to apply cost reflective tariffs because of a diversity of reasons, including that a large fraction of the population cannot afford the costs, that customers may not want to pay for a service of poor quality, and that is popular to maintain the tariffs low, even if this means that the government has to spend money in bailing out the Discos instead of using it for other purposes, while condemning the discos to permanent underperformance.

[15] This creates an interesting dilemma. If the SPV is not mandated to improve reliability and quality of service in these areas, or it does not have the economic incentives to do it, then a potential market opportunity opens in using off-grid solutions – either mini-grids or standalone systems – to offer an alternative reliable and high-quality supply to those customers that might be interested in paying extra for it – typically commercial, industrial and well-off residential customers. Since Tata Power is also in the off-grid business, this may create some conflict of interest. There might be some better approach to incentivize the adoption of societal least cost solution in each case.

[16] This is the classical regulatory dilemma concerning the incentives created by any specific regulation on the relationship between CAPEX and OPEX for any Disco. In fact, often the same goal in reliability or quality of service can be achieved by capital investment or by increasing O&M activities. The specific regulation determines in which direction the distribution company will be incentivized to perform.

In a concession agreement, the Government can fix a value of RABB for the B assets well below what should be in reality. This has the effect of creating a low value for the corresponding CAPEXB annuity, resulting in a low tariff, as desired, but one that is cost-reflective, if the “tuned” value of RABB is accepted as the true value of the assets. Although the tariff in this case is cost-reflective, the ad-hoc declaration of a low value for the RABB is actually a tariff subsidy for the end customers.

In the concessions of Delhi and Odisha it has been agreed that the concessionaire will own 51% of the company during the duration of the concession, while the Government of Delhi or the Government of Odisha, respectively, will own the remaining 49%. This seems to imply (to be verified) that the amount paid by the concessionaire in the auction will entitle it to an initial 51% of the rights to the revenues of the company as well as to the control of the board. The amount paid also determines the value of the initial RAB (which is RABB, since RABA is zero at the outset).

The economic terms of the concession.

The concession is awarded by means of an auction, where several concepts are evaluated. First, the key economic component of the auction is the bid on the amount to pay to the Government to get the concession. The regulator announces a minimum value for this amount, and the bidders will equal or better the minimum value, or they will quit the auction.[17] This minimum value set by the regulator can be interpreted as the value RABB of the existing distribution assets that the concessionaire will be able to use while their physical lives last and only until the end of the concession[18]. Note, however, that the concessionaire will just manage but not own the assets B, for which no compensation will be given at the end of the concession. On the other hand, at the termination of the concession, if it is not renewed, the concessionaire will receive the residual value of all the assets A that have been included in the RABA (and of any investment associated to the assets B and allowed to be included in the RAB). This completely ends the relationship between the concessionaire and the Government.

The second economic component of the auction may be a detailed business plan, whose soundness will be evaluated in addition to the other two components. This has been the case in the auction for the concession in Odisha that was awarded to Tata Power.

[17] In the case of Uganda, the concessionaire Umeme pays an annual fee for the use of the existing distribution network (assets B).

[18] Therefore, this value is NOT exactly the RABB, but the economic value of leasing these assets for all purposes of economic and managerial control of the company for the duration of the concession. Subtle point.

And the third and final component are commitments to meet performance targets, such as loss reduction, reliability metrics, or number of new connections, whose level of realization will be subject to penalties or credits. In the case of the Odisha only a loss reduction commitment was required. In the case of Delhi, year-on-year reduction in AT&C losses were sought for a 5-year period.

To provide certainty to the private investors, in Delhi's case the government issued policy directions to provide clarity on bidding criteria, availability of assured returns and tariff fixation criteria, among other parameters. For instance, prior to the bidding, the bulk supply tariff order was issued by the regulator from 2002 until the end of 2006-07 to provide clarity on revenue/expense outlook[19].

Revenue requirement, tariffs and subsidies.

The regulator will compute the tariffs that will allow to recover the established total revenue requirement, including now the A and B assets. The initial tariffs must take into account the present value of total losses, either technical or commercial, so that the estimated revenues to be collected allow the recovery of this revenue requirement. The tariffs in the following years will be computed on the basis of the prescribed trajectory of losses. Therefore, the SPV has the incentive of reducing the total losses as much as possible, while it is cost effective, taking also any incentive regulation into account.

Note the conceptual difference between the revenue requirement, which needs to be cost reflective, since otherwise no private investor would be willing to participate in a concession agreement, and the estimated revenue collected from the tariffs that are determined by the regulator. If the tariffs are designed to be cost-reflective, both quantities will be equal. If the amount to be collected by the tariffs is below the cost of supply, then a subsidy is needed to make the distribution activity whole. This subsidy can be deployed in different ways: for instance, a direct individual subsidy to some categories of customers; an annual lump sum to the concessionaire to make it whole; or a reduction in the wholesale price of the electricity that is purchased by the SPV to meet the demand of its customers.

If the concession covers a rural territory that has not been electrified yet, or that has been electrified for a minimum demand level that could grow substantially under a more robust supply of electricity, or where there is connection, but of poor reliability and quality, then the necessary investment to achieve a satisfactory electricity supply can be substantial. If the physical condition of the B assets is poor, significant

[19] https://www.tatapower-ddl.com/Editor_UploadedDocuments/Content/TPDDL%20Case%20Study_COMPLETION%20OF%2010%20YRS.pdf

investment may be needed to achieve the levels of performance required in the concession contract. Proper metering and customer attention may require additional investment and O&M costs. Even if the tariffs prior to the concession contract were cost reflective, they will be probably insufficient to cover these new high costs, and therefore an additional subsidy might be needed to make the concessionaire whole. As a hypothetical example, this would be the case of Umeme, the only distribution company in sub-Saharan Africa (with Seychelles) where tariffs are cost reflective, in case a new concession – for a new term starting 2025 – is negotiated that includes the obligation of universal electrification in some territory (perhaps the entire country), which mostly consists of rural electrification. Then, a distribution activity that was initially financially viable without subsidies will now need to be subsidized.

Expanding rural connections.

The franchisee and distribution concessions discussed so far have largely focused on urban compacts. The case of Odisha will be a unique case where a private distribution concession will have a large rural area within its territory, although the infrastructure for connecting majority rural areas has already been established and the focus will be on improving quality and reliability of supply as discussed earlier. In this case, since the state's regulations allow for "under the radar" mini-grids, then private players can come in unsolicited or as franchisees and service underserved areas without connecting to the grid. This way tariff differentiation is possible and if planned well and C&I customers could be brought into these mini-grids, then their developers can recuperate their investments before the grid supply is made more reliable or demand grows enough to justify investment in heavy wires.

Senegal's Rural Electrification Action Plan (PASER) offers some insights on the use of distribution concessions for expanding electricity access. One of the private sector concessionaires is Energie Rurale Africaine/EDF. The winning bid was awarded on the basis of a single parameter: the number of promised connections (to be achieved through grid and other solutions – technology neutral). Concessionaire enters into a 25-year contract with ASER as well as with the Ministry of Energy. Six bidders promised a total of 106,601 rural connections. Only 3,726 had been reached as of Oct 2015. More customers (approximately 2,500) were connected via solar home systems than via grid extension (approximately 1,300).

Substantial challenges have been faced in the programme. The current pricing system has allowed price differences to emerge between the customers supplied by SENELEC and those supplied by the concessionaires. In turn, this has led to significant tensions, particularly in concession areas bordering SENELEC's service areas. The high cost of service delivery in the concession areas is also a key challenge for the viability of the concessionaires. ERA estimates that in its concession area, grid extension costs are twice as much as solar home system installations. Because the electricity uptake rate is much lower than expected (20% in the targeted villages instead of the forecast 70%), the actual cost of a grid connection per user is eight times more than a solar home system[20]. A comprehensive least-cost electrification plan should have formed the basis of a national electrification strategy that guides the design of the concession area and estimation of connection costs covering the various electrification solutions as associated subsidy requirement.[21].

IV. PRIVATIZATION

Under a full privatization approach, the government intends to transfer the full operational and economic rights of distribution to the private sector indefinitely. This represents a step beyond DC wherein private sector participation is limited by the term of the concession with no ownership of distribution assets. The privatisation may be complete i.e., involving transfer of ownership of distribution to a completely private entity, or partial wherein the government holds a minority stake. In the case of Nigeria, for instance, the Government is a minority shareholder (40%) and retains rights on decisions related to the company, for instance on reselling the assets.

The economic terms of the privatization (core investor sale).

Nigeria's privatization of distribution companies involved selling controlling equity stake (60%) with a view to rapidly improve its operational efficiency. Shares in the distribution companies were sold to private investors as "clean skin" companies without any prior liabilities[22]. The total value of the sale price for the privatized assets amounted to USD 2.5 billion (Ogunleye, 2016[23]). Unlike traditional transaction approaches where bidders bid on price for the equity shares, bidders bid on the basis of a business plan depicting the trajectory of technical, commercial and collection loss improvements over a five-year period[24]. Some distribution companies have claimed that the power assets purchased during the privatization process were overvalued

[20] http://documents.worldbank.org/curated/en/710071498161444599/pdf/116653-WP-PUBLIC-P150241-36p-Detailed-Case-Study-Senegal.pdf

[21] http://documents.worldbank.org/curated/en/710071498161444599/pdf/116653-WP-PUBLIC-P150241-36p-Detailed-Case-Study-Senegal.pdf

[22] Samuel Sunday Idowu, Jide Ibietan & Ayo Olukotun (2019): Privatization of Power Sector in Nigeria: An Evaluation of Ibadan and Ikeja Electricity Distribution Companies Performance (2005–2018), International Journal of Public Administration, DOI: 10.1080/01900692.2019.1672183

[23] Ogunleye, E. (2016), Political economy of Nigerian power sector reform, WIDER Working Paper 2016/9.

[24] https://www.lexology.com/library/detail.aspx?g=3b959f61-5763-4029-89cf-d107475c5276

because the data and information provided to them by the government was inflated (Ogunleye, 2016).

Despite privatization, evidence suggests that the distribution companies have substantially underperformed, especially on parameters related to electricity supply, pricing/billing and metering[25]. One of the primary reasons for this has been the lack of capital expenditure and inadequate tariffs to ensure cost-recovery.

Revenue requirement, tariffs and subsidies.

To achieve the promised reductions in AT&C losses required substantial capital expenditure which has not been mobilised for several reasons. First, the structure of the privatization process did not make a provision for an additional ring-fenced income stream to repay the capital needed to be mobilised to reduce losses. It was envisaged that improving cash collection and operations would meet the requirements of this additional investment. Second, on taking over control a number of privatised distribution companies reported much higher AT&C losses, operational costs and persistent non-payment by certain powerful large-scale consumers than reported during the bidding process thus requiring substantially higher capital investments (World Bank, 2016[26])[27]. Third, tariff regulations are not ensuring cost-recovery for the distribution companies thus inhibiting their ability to raise additional capital for investment.

The level of losses that a bidder proposes to reduce are incorporated in the Multi Year Tariff Order (MYTO)[28]. MYTO stipulates the annual investment requirement, allowable operational expenditure, approved rate of return on equity and other allowable expenses for each distribution company[29]. However, the application of the tariff policy has been inconsistent and unresponsive to the changing macro-economic environment which has led to substantial under-recovery on the part of the distribution companies. For instance, the lack of adjustment for the depreciation of the naira in 2016 severely affected the revenues of the distribution companies, as approximately

[25] Samuel Sunday Idowu, Jide Ibietan & Ayo Olukotun (2019): Privatization of Power Sector in Nigeria: An Evaluation of Ibadan and Ikeja Electricity Distribution Companies Performance (2005–2018), International Journal of Public Administration, DOI: 10.1080/01900692.2019.1672183

[26] World Bank (2016), Achieving Universal Access in the Kaduna Electricity Service Area, http://documents.worldbank.org/curated/en/782491487138851242/Achieving-universal-access-in-the-Kaduna-electric-service-area

[27] The operational capabilities of some of the privatised assets are reported to have even deteriorated throughout the privatisation process as scarce resources were no longer directed towards the continued operation and maintenance of those assets.

[28] MYTO is a tariff model adopted by the Nigeria Electricity Regulatory Commission to set wholesale and retail prices for electricity by employing a building blocks approach to determine total industry revenue requirement that is tied to measurable performance improvements and standards.

[29] https://www.lexology.com/library/detail.aspx?g=3b959f61-5763-4029-89cf-d107475c5276

65% of the sector costs are denominated in foreign currency. In turn, inadequate service delivery has constrained the government's ability to raise tariffs (World Bank, 2018)[30]. To address the situation, a major review of the MYTO is underway to ensure convergence between tariff revenue and revenue requirements of the distribution company. The revenue requirements will be based on new performance parameters and Performance Improvement Plans (PIPs) of distribution companies.

In the absence of cost-reflective tariffs and given the current financial difficulties faced by distribution companies, public financing instruments will be critical to meet the CAPEX funding needs not covered by tariff revenues. With a large percentage of population without access to electricity and a number of commercial and industrial consumers utilising captive generation to meet electricity needs, a substantial financial outlay in the form of subsidies will be necessary to make the necessary investments in the distribution sector, improve reliability of supply and raise electrification rates. At present, the regulatory framework for tariffs covering the next 5-10 years does not make allowance for large scale investment in electrification.

With limited capacity to expand electricity access coverage, distribution companies are seen to partner with private entities to service unconnected areas within area of coverage. At a small-scale, one example is Nigeria's Wuse market. Abuja Electric Distribution Company entered into a tripartite agreement with GVE Projects Ltd. (a private entity) and the Wuse Market Traders Association (representing the consumers) to develop a 1 MW inter-connected mini-grid to service the Wuse economic cluster in Abuja. The project brings 3, 000 consumers that are diesel-generator dependent on the consumer base of the grid.

Xxx we have to mention the DESSA initiative by Abuja Electric (AEDC). xxx

At a relatively larger-scale is the example of Konexa that has entered into an MoU with Kaduna Electric to service unserved areas within the territory. Konexa has identified a pilot area around 11kV feeders serving 50,000 people and aims to deploy a suitable mix of grid-based and off-grid (mini-grids and solar homes systems) based on a least-cost electrification assessment conducted. It also aims to carve out SPVs from Kaduna's territory containing utility assets and customers to create attractive investment opportunities.

V. LESSONS FOR IDF IMPLEMENTATION

The diverse experience of privatization within low-access countries offer valuable insights on the implementation of the IDF. Adapted to local contexts, the IDF

[30] http://documents.worldbank.org/curated/en/704121518922836847/pdf/NIGERIA-PAD-01292018.pdf

represents an approach to reach universal access to reliable, affordable and sufficient electricity access by achieving integration across three main areas: modes of electrification (grid, mini-grids and stand-alone systems), private sector participation in distribution and end-uses.

At the core of the IDF is an entity with the responsibility for delivering electricity access to all within its area of coverage. Based on the cases analysed in this paper, this sector highlights some key lessons for designing distribution concessions for entities to substantially improve distribution activities as well as expand access to electricity.

1. **Estimating true cost of delivery for different modes of electrification**
    - A least-cost electrification plan is necessary for basing technical and financial bids on cost of service delivery. Underestimation of the same (and low up-take) has been a key reason for limited success of concessions with international private sector participation (e.g., Senegal).
    - Government has to take a leadership role in developing a comprehensive electrification strategy that integrates the three modes: grid, mini-grids and stand-alone systems. The outcomes from electrification model can provide valuable insights for informing concession design and provide a common reference point for competition private sector entities.
2. **Concession design**
    - The concession documents should address the following key features: economic conditions to use the existing assets, remuneration and final treatment at the end of the concession of the new assets, tariff structure, scheme of financial support, mandatory investment, key performance indicators, incentives and penalties, monitoring, inspection and enforcement, suspension/termination for breach of agreement, maintenance standards and safety requirements.
    - Substantial capital expenditure will be needed to improve distribution within existing coverage areas as well as to expand access to unconnected areas. The concession must provide a clear approach for cost-recovery of CAPEX (e.g., inclusion in RAB for determination of revenue requirement). Assured return on equity for capital investments, such as in the case of Umeme and TPPDL, are preferred.
    - Where a mix of electrification modes are followed, the regulator should consider the capital investments in off-grid solutions as part of the RAB for determination of revenue requirement.
    - Gaps between revenue requirement and tariff revenue needs to be addressed through subsidy. In the specific case of expanding electricity

access, the subsidy requirement can be determined through planning tools and must be accounted for in the remuneration model for the distribution company. The use of grants to reduce investment cost is not sustainable in the long-term.

3. **Defining area of concession**

   - The design of concession are must account a number of factors: minimum size to attract private sector interest (e.g., set at 10,000 to 30,000 customers in the case of Senegal); optimum mix of rural-urban compact (e.g., Odisha); and existing consumption, topography and density.
   - In defining area of concession to deliver universal electricity access, target scale to tackle the nature of the electrification challenge. Substantial lessons exist from countries to apply to designing concessions that also address electrification.
   - Areas with high AT&C losses offer immediate opportunities for additional revenue generation with limited capital expenditure. Experience from Tanzania, Namibia and states in India demonstrate the substantial revenue gains from including areas with high AT&C losses within concession areas for private sector participation. However, the incremental revenues are known to not be sufficient to meet growing CAPEX needs of distribution and electrification (e.g., Tanzania, Nigeria).

4. **Parameters for competition**

   - The auction process to select the private sector concessionaire may be designed in several ways depending on how the concession is designed. Ideally, a multi-criteria evaluation criteria is preferred that includes multiple performance parameters. Box below provides a sample multi-criteria evaluation criteria for a concession.

Box. Sample multi-criteria concession bid

The Bidders are required to submit a five year Business Plan and turnaround strategy. The business plan has the following key components and corresponding weights:

1. AT&C Loss Reduction [20%]
   a. Commitment at the of 3rd and 5th year of operation.
   b. Strategy and implementation plan for reduction
   c. Plan for improvement in metering, billing methods & revenue collection, etc.

2. Capex and Financing Plan [15%]
    a. Annual capex plan for first 5 years of operation with a set minimum cumulative investment in the first 5 years.
    b. Financing plan to meet the capex requirement.
3. Plan for recovery of past arrears [5%]
    a. Quantum of Past Arrears they commit to collect annually for first 5 years.
4. Human Resource Plan [7.5%]
5. Customer Service [5%]
6. Prior experience/capacity of operating in power/electricity business [25%]
7. Additional commitments proposed by the Bidder (e.g., customer development & engagement programmes, CSR commitments, etc.). [7.5%]

5. Transparency

A key lesson emerging from countries that have pursued private sector participation in distribution is the importance of transparency at all stages of the process of privatisation. Experience from Senegal and Nigeria illustrates how lack of clarity on the current status of the distribution sector can lead to inefficient outcomes from the privatization process. Transparency across the following key parameters is particularly key:

- Current status of AT&C losses based on which tariff is determined and bidders develop their proposals (and associated assumptions on capex requirements, revenue growth, etc.).
- Current status of distribution infrastructure.
- Tariff determination process, clarity on return on equity expectations, coverage of capital expenditure in RAB, depreciation rates for various types of infrastructure.
- Transparency in bulk power costs and secure contracts with generators for supply.

Annex 1: Management contracts

TANESCO and NETGroup in Tanzania

In 2002, the Government of Tanzania entered into a two-year management contract with NET Group Solutions of South Africa to oversee the day-to-day strategy and operations of the utility, Tanzania Electricity Supply Company Limited (TANESCO). This involved NETGroup managers to take over top four TANESCO executive positions (later raised to five), with the utility remaining state-owned. The contract spanned a total of 56 months beginning May 2002, comprising two phases of 27 and 29 months respectively.

The scope of the work was designed around specific performance incentives. The initial objective was the financial turn-around of TANESCO in preparation for complete privatization. Phase I (2002-2004) contract incentives were mainly focused on increasing revenues. Technical loss reductions and quality of service standards were also goals. In the second phase (2004-2006), the scope was expanded to include technical turn-around by redirecting revenue gains from the first phase into new, utility-financed investments to improve technical performance. System reliability and electrification targets were also added.

The contract remuneration comprised of fixed fees and performance-based variable fees. NETGroup is estimated to have received USD 18-19 million for the duration of the contract, of which USD 8.5 million were fixed retainer fees and remainder in success fees. The contract was financed from utility revenues and donors (sida funds administered through the World Bank).

In terms of results, the management contract brought about significant changes in utility operations and generated a near doubling of utility revenues. TANESCO's monthly revenues increased from USD 10-12 million in 2001 to USD 16 million by mid-2004 and USD 22-24 million in 2005-06 (Ghanadan and Eberhard, 2007). The revenue-related success fee for the NETGroup totalled USD 8-10 million or about 4% of net increases in revenues achieved during the management contract. Increases in revenues resulted from multiple factors (Ghanadan and Eberhard, 2007):

1. **Growing electricity sales:** 37% rise between 2001 and 2006, primarily due to increasing number of electricity consumers.
2. **Increasing tariffs:** Electricity tariffs grew 28% between 2001 and 2006, with residential consumers seeing a 39% growth and industrial users experiencing a reduction of up to 28%. Significant structural changes to tariffs were implemented. Historical cross-subsidy from industry to residential and light commercial customers was undone to make industries regionally competitive.
3. **Improving collection levels**: Increased from 69% in 2001 to 85% in 2002. Enforcement of payments from public institutions were prioritised, with high-

profile service cut-offs with support from the highest levels of government. For large industrial consumers, payback schedules for arrears were negotiated without disconnection. For residential and light commercial consumers, efforts involved pre-payment meters and large-scale cut-offs.

Non-revenue objectives were largely not met. Technical power losses were maintained at starting levels, around 22% in 2006, primarily due to insufficient investment infrastructure. Related, reliability of supply also did not improve. Levels of new electrical connections did not increase substantially, remaining steady at about 2,500 connections per month. A large part of the reason for not meeting the non-revenue objectives has been the wider sector conditions that hindered the utility from generating surpluses for new investments.

The high generation costs prevented TANESCO from utilising its growing revenues for improved investment and technical performance. Revenue surpluses were going into IPP payments and the ability to finance investments for reliability or electrification had eroded. Also, customer service had largely been omitted from the contract creating a scenario, especially for residential and small commercial users, where costs were increasing without tangible improvements in services.

The contract came to an end in December 2006 following which TANESCO reverted to full public management.

Financial Operating Efficiency (Revenue versus Costs)[20]

$$\text{Success Fee}_{m,\text{Efficiency}} = (\%\text{Costs/Revenue}_{m,\text{Previous year}} - \%\text{Costs/Revenue}_{m,\text{Current year}}) \times \text{US\$ } 10{,}000$$

Operating Efficiency Success Fee calculated at a rate of US$ 10,000 per percent decrease in the monthly ratio of Operating Costs to Revenue Collected compared with the value from the equivalent month in the previous year[21].

Power Losses

$$\text{Success Fee}_{m,\text{Power Loss}} = (\%\text{Losses}_{m,\text{Previous year}} - \%\text{Losses}_{m,\text{Current year}}) \times \text{US\$ } 3{,}000$$

Power Loss Success Fee is calculated at a rate of US$ 3,000 per percent decrease in total monthly losses (technical and non-technical) compared with total losses from the equivalent month in the previous year[22].

Quality of Supply and Service[23]

$$\text{Benchmark}_{\text{Quality of Supply and Service}} = -(\%\text{Target}_Q - \%\text{Attained}_Q) \times (\text{Success Fee})$$

Quality of Supply and Service benchmark is calculated as a potential reduction in the Operating Efficiency Success Fee for each percentage point performance falls below the benchmark in each quarter; no bonus is earned if the benchmark is met. Targets increase from 70% to 100% over Phase 1and are a composite of eleven elements[24].

Financial Bonus (Profits)

$$\text{Financial Bonus} = (\text{Actual Profit}_Q - \text{Target Profit}_Q) * 4.0\%$$

Financial Bonus is calculated at a rate of 4% of operating profits above target quarterly profits of US$ 6 million, US$ 7million, and US$ 8 million in each quarter of 2004, 2005, and 2006, respectively.

System Reliability

$$\text{System Reliability Bonus}_{Q,n} = (\text{CAIDI}_{Q,n-1} - \text{CAIDI}_{Q,n}) * \text{US\$}1{,}000$$

$$\text{Where, CAIDI} = \frac{\sum (\text{interruption, min}) * (\text{\# customers affected})}{(\text{total number of customers affected})}$$

CAIDI is the Customer Average Interruption Duration Index. The System Reliability Bonus (or penalty) is calculated at rate of US$ 1,000 per minute of improvement (or deterioration) in quarterly CAIDI index compared with the measurement of the CAIDI index from the previous quarter.

Electrification

$$\text{Electrification Bonus}_Q = (\text{Actual Connections}_Q - \text{Target Connections}_Q) * \text{US\$ } 30$$

Electrification Bonus (or penalty) is calculated at rate of US$ 30 for each new connection above (or below) a target connections for the given quarter. Electrification targets only begin in 2005-2006; there are no targets for 2004.

NamPower and Northern Electricity in Namibia

In 1996, Northern Electricity signed a six-year management contract with NamPower to operate distribution infrastructure in the north (ECA, 2015). NE did not own any assets; however, it was responsible for all operating expenses and revenues related to the distribution system. During the term of the management contract, substantial improvements in collection rates and reliability of supply were recorded. Collection rates grew from under 50% to 99%, while investments in network upgrades (with government assistance) helped reduce power outages. Losses were reduced from 49% in 1996 to 7% by 1990. A five-year network development plan was also developed, along with a preventive infrastructure maintenance programme.

The management contract had a limited electrification mandate. Yet, NE enforced a rural electrification levy to collect revenues to make the required investments to increase the rate of connections. The autonomy to implement tariff changes played a critical role in increasing the rate of new connections.

Unlike the Tanzania's case, the management contract with NE was not highly prescriptive both in terms of governance or performance measurement. It did not outline methods for evaluating performance relative to a few specified indicators, therefore providing NE flexibility to develop its own methods and define its own terms for success[31]. While such an approach is beneficial when interests of the parties are aligned, it can be challenging when they are not. One of the drawbacks noted was the

[31] http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/EconOneResearchInc_Northern_Electricity_Distribution.pdf

lack of clarity in the contract on asset valuation and transfer required after NE's license was not renewed.

Despite successes in reducing non-technical distribution losses, improving power system reliability and achieving higher connection rates, the contract was not renewed in 2002. A reason was NamPower's objective to extend influence over the distribution network, which after NE's involvement seemed to be a profitable business (ECA, 2015). As a result of the positive outcomes of NE's engagement in distribution, several Town Councils (e.g., Rehoboth, Keetmanship, Karasburg) entered into management contracts and joint ventures with private sector companies to manage and operate the distribution network.

Annex 2: Franchisee cases

Odisha, India

The distribution licensee, Central Electricity Supply Utility (CESU), in the state of Odisha adopted an input-based franchise in 2012 with an incremental revenue sharing model. It essentially involves the franchisee to carry out all commercial and operational activities, invest in technology and metering to reduce the AT&C loss for a period of five years, without any extra expenditure by CESU. The incremental revenue beyond the base line revenue realisation per unit (RPU) will be shared between franchisee and CESU[32]. Penalty is imposed for not realizing the base RPU on the DF and it is revised every year based on the tariff indexation formula. The franchisee will not be remunerated till the RPU value exceeds the base line. The additional revenue will be shared with CESU in the ratio of 60:40 during the first year and 50:50 for the remaining 4 years. In 2012, bids were invited for five circles and the bidding was carried out on the basis of a fixed loss reduction trajectory proposed by the bidder and on-year percentage sharing of incremental revenue with CESU. One of the major risks with this model is that the regulatory function is played by the original distribution licensee, rather that the state regulatory agency.

Bhiwadi, India

Franchisee discharges all duties and responsibilities of the distribution licensee (e.g., metering, billing, repair, CAPEX expenditure, consumer engagement). The franchisee pays to the licensee for input energy injected (‘input rate’). This input rate assumes a certain level of ATC loss reduction. The competitive tender is based on the input rate willing to pay for each year of the franchisee term. The consumers are charged same tariff as the rest of the licensee area. The franchisee has autonomy to plan and execute CAPEX expenditure. At end of term, the licensee reimburses the franchisee at the depreciated cost of the assets[33]. A Minimum Capital Investment Plan will be integrated into the franchisee agreement for the contract period. The Distribution Franchisee shall make a minimum investment equivalent to 50% of annual revenue for the Base Year spread over a period of 5 years. The franchisee shall roll out its investment in such way that at least 10% of the minimum investment plan is spent every year for the first five years of the contract period. The input energy rates bid by the franchisee shall be deemed to have taken into account the cost of finance and depreciation on account of these investments.

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[32] https://www.cescoorissa.com/franchisee/Base_Paper.pdf

[33]

Konexa

Signed commercial agreements with two DisCos and identified pilot area around 11kV feeders serving 50,000. Aims to deploy solar home systems and mini-grids and refurbishing the existing grid infrastructure in 2020. Carve out SPVs containing utility assets that attract infrastructure investors. First project in Kaduna Electric that will be developed by Konexa/Shell Foundation, will invest USD 25 million in two feeders that supply energy to 10,000 customers.

Annex 3: Distribution concession cases

Umeme in Uganda

In 2004, Umeme Limited, a private consortium comprising Eskom, Globeleq and (later) Actis, was granted a concession for Uganda's main state-owned distribution grid for a period of 20 years (Hosier et. al., 2017). Umeme covers 95% of the country's distribution network. The main objective of the concession was to reduce the burden on the public exchequer by improving the operational and financial viability of the distribution sector through loss reductions and increased bill recovery rates. Umeme's concession area was defined as the existing lines and the area within one kilometer on either side of the existing distribution network. Expanding electricity connections in rural areas beyond the concession zone was not one of the objectives set for the concessionaire.

Umeme's case is considered as one of the most successful concession experiences in Sub-Saharan Africa with regard to the transformation of an ailing state-owned utility into a profitable business able to meet service stringent quality requirements (Jacquot, et. al., 2019)[34]. When Umeme took over in 2005, the network comprised a total of 290,000 connections, which has grown to 1.2 million in 2018. In the years before the creation of the concession, the state-owned utility had been slowly expanding the grid in both urban and rural areas. Therefore, Umeme's concession area contained rural infrastructure that was not being effectively exploited. Umeme took over the assets and began adding connections within its service area.

System losses have fallen from 35% in 2005 to 16.5% today and bill collection rates increased from 80% to 99.1% over the same period[35]. Importantly, it has been able to attract substantial private capital into the distribution sector that other private sector initiatives have struggled to achieve, especially in sub-Saharan Africa. Since 2005, it has invested over USD 600 million in the distribution system, attracting debt financing to the tune of USD 265 million. The future strategy for Umeme is to focus on the industrial hubs and areas of high economic activity alongside the rural electrification drive to generate new demand[36].

Investment risks in Umeme's case were mitigated through several measures – the concession design guaranteed a 20% return on assets, escrow fund to ensure

[34] Jacquot, G. (2019), Assessing the potential of electrification concessions for universal energy access: Towards integrated distribution frameworks. MIT Energy Initiative Working Paper, http://energy.mit.edu/wp-content/uploads/2019/09/MITEI-WP-2019-01.pdf

[35] https://www.umeme.co.ug/umeme_api/wp-content/uploads/2019/07/UMEME_Power_Book_web.pdf

[36] https://www.umeme.co.ug/umeme_api/wp-content/uploads/2019/07/UMEME_Power_Book_web.pdf

payments from the government to the concessionaire, political risk insurance from MIGA and partial risk guarantee from IDA (World Bank, 2015)[37]. While some challenges have been faced, including a regular review of Umeme's 20% return on investment, Umeme's strategy of bringing in investment to resuscitate the sector, increasing collections, and then re-investing in the sector has allowed it to meet, and in some cases exceed, the targets set by ERA (Godinho and Eberhard, 2019[38]).

With respect to expanding access, the Ugandan Rural Electrification Agency has started to subsidize the construction of new, rural feeder lines and the agency then either hands ownership of the lines over to UEDCL for operation by Umeme (if within the Umeme footprint), or the REA retains ownership leasing them out to cooperatives or private entities for operations and maintenance. However, given the lack of technical and financial capacity, these smaller operators mostly depend on REA for major maintenance and replacement of damaged plant and equipment. While Umeme and REA have made some inroads to advancing access, this is seen to be one of the oversights of the new model. The Umeme concession agreement does not have access targets, and is heavily biased towards reducing losses, increasing collections, and stabilizing the service in the networks inherited from UEB.

Umeme's responsibility in energy access is limited to its concession zone, which extends within 1km of the existing grid. The extension of the grid into rural areas is currently financed by public entities—mainly the Ugandan rural electrification agency—and assets are later transferred to local concessionaires, sometimes operating within Umeme's operation zone. While such concessions were not designed to address energy access, utilities may expand their concession area and engage into electrification programs provided that adequate guarantees, subsidies, and flexibility regarding the mode of electrification (through grid extension, mini-grids, or SHS) were granted[39]. The adequacy and extent of this supportive environment then determines the scope and speed of electrification.

In the case of Umeme (Uganda), it pays lease payments to the Uganda Electricity Distribution Company Limited (UEDCL) under the concession agreement. Assets added to the distribution network are not recognised as property, plant and equipment, but rather as intangible asset equal to the carrying value of the assets added to the distribution network less the residual amount (buy-out amount), amortized over the

[37] http://documents.worldbank.org/curated/en/354661498163378835/pdf/116661-WP-P150241-PUBLIC-53p-Detailed-Case-Study-Uganda.pdf

[38] Godinho, C and Eberhard, A (2019), Learning from Power Sector Reform: The Case of Uganda, Policy Research Working Paper, The World Bank Group.

[39] Jacquot, G. (2019), Assessing the potential of electrification concessions for universal energy access: Towards integrated distribution frameworks. MIT Energy Initiative Working Paper, http://energy.mit.edu/wp-content/uploads/2019/09/MITEI-WP-2019-01.pdf

useful lives of the underlying property, plant and equipment. The financial asset represents the amortised cost of capital investments by the Company, which will not have been recovered through the tariff methodology at the time of transferring the distribution network back to UEDCL at the end of the Concession (buy out amount). It is computed as the gross accumulated capital investments less cumulative expected capital recovery charges at the time of transfer and discounted at an internal rate of return of 20.4% and a weighted average cost of capital (WACC) of 5.14% for investments yet to be approved by ERA over the remaining period of this concession[40]. Uganda also has examples of rural-only electrification concessions (e.g., 20-year concession with Industrial Promotion Services/WENRECo to build, own and operate electricity generation, distribution and sales facilities in the West Nile region)[41].

Tata Power Delhi Distribution Limited in Delhi (India)

The Government of National Capital Territory of Delhi (GNCTD) invited private players for the distribution of electricity in three zones in Delhi. It was envisaged that the private participant would have a 51% stake and GNCTD would hold the remainder in the new company (TERI and GCEP, 2015[42]). Ownership of distribution system transferred to private party. The selection criteria for the competitive bidding process was the year-on-year reduction in AT&C losses to be achieved between 2002 and 2007. To provide certainty to the private investors, the government issued policy directions to provide clarity on bidding criteria, availability of assured returns and tariff fixation criteria, among other parameters. For instance, the policy assured a 16% post-tax return on equity invested in the business subject to meeting the loss reduction targets. It further noted that prior to the bidding, the bulk supply tariff order would be issued by the regulator from 2002 until the end of 2006-07 to provide clarity on revenue/expense outlook[43].

Tata Power Delhi Distribution Limited (TPDDL) won the north and northwest circle. TPDDL has achieved a reduction of AT&C losses from 53% in 2002 to about 8% today

[40] https://www.umeme.co.ug/umeme_api/wp-content/uploads/2019/08/Umeme-Interim-Condensed-Financial-Statements-June-2019.pdf

[41] http://documents.worldbank.org/curated/en/354661498163378835/pdf/116661-WP-P150241-PUBLIC-53p-Detailed-Case-Study-Uganda.pdf

[42] https://www.teriin.org/eventdocs/files/TERI-GSEP-PPP-in-Electricity-Distribution_Case-Studies.pdf

[43] https://www.tatapower-ddl.com/Editor_UploadedDocuments/Content/TPDDL%20Case%20Study_COMPLETION%20OF%2010%20YRS.pdf

(CRISIL, 2019[44], TPDDL, 2015[45]). This was achieved through significant investments in the augmentation of networks, introduction of state-of-the-art technologies and social intervention (e.g., enforcement). In the decade between 2002 and 2013, TPDDL incurred capital expenditures of over INR 3000 crores (or USD 418 million at current rates)[46].

A key challenge faced is the role of the state governments in the fixation of tariffs (CRISIL, 2019[47]). The rising bulk power purchase cost which represent over 70% of the total cost for TPDDL, and the regulator disallowing tariff hikes has led to an accumulation of regulatory assets which stood at over INR 4,500 crores (USD 628 million) as of Q2 FY20[48]. Between 2008 and 2015, for instance, bulk power cost rose by 143% while retail tariff grew by 74%[49]. A clear roadmap is demanded for the amortization of regulatory assets, but importantly also highlights the importance of integrating tools for periodic tariff revisions and surcharges to reflect the changing economics for distribution companies.

Energie Rurale Africaine in Senegal

SENELEC, the vertically integrated state-owned utility in Senegal, carries out transmission, distribution and energy purchase in majority of the country. In 1998, given the low rate of rural electrification in the country, the government launched the Rural Electrification Action Plan (PASER) and divided the country into ten concessions for allocation to distribution concessionaires.

The winning bid was awarded on the basis of a single parameter: the number of promised connections (to be achieved through grid and other solutions – technology neutral). Six bidders promised a total of 106,601 rural connections. Concessionaires receive a subsidy from the rural electrification agency for a portion of their initial

44 https://niti.gov.in/sites/default/files/2019-08/Final%20Report%20of%20the%20Research%20Study%20on%20Diagnostic%20Study%20for%20power%20Distribution_CRISIL_Mumbai.pdf

45 https://www.tatapower-ddl.com/Editor_UploadedDocuments/Content/Delhi%20Performance%20Overview%20%20Financial%20Data_July%202015.pdf

46 https://www.tatapower-ddl.com/Editor_UploadedDocuments/Content/FAQ's.pdf

47 https://niti.gov.in/sites/default/files/2019-08/Final%20Report%20of%20the%20Research%20Study%20on%20Diagnostic%20Study%20for%20power%20Distribution_CRISIL_Mumbai.pdf

48 https://www.tatapower.com/pdf/investor-relations/8.%20Analyst%20Presentation%20Q2%20Financial%20Results%20%20-%2008.11.2019.pdf

49 https://www.slideshare.net/AmitKumar464/what-is-a-regulatory-asset

investment cost, no OPEX subsidy. This is determined during the negotiations after tender process.

One of the private sector concessionaires is Energie Rurale Africaine/EDF. Several concessionaires have encountered numerous barriers delaying connection progress.

By October 2015, the total number of connections made by all concessionaires as of late 2015 was approximately 3,700. More customers (approximately 2,500) were connected via solar home systems than via grid extension (approximately 1,300).

The electricity sector regulator, the Commission de Régulation du Secteur de l'Electricité (CRSE), has power over the PPER concessions. The tariffs and service standards are initially specified in the concession contract but may be revised on a five-year cycle or on an exceptional basis, if the financial conditions originally established in the contract have changed. Concessionaires must charge cost-recovery tariffs for each of the electrification technologies deployed. If a concessionaire planned to undertake grid extension and purchase power from SENELEC, the tariff would be set as the national medium voltage tariff minus 25 percent (representing the distribution cost), plus a small royalty per kWh required for maintenance of the electrical system.

The current pricing system has allowed price differences to emerge between the customers supplied by SENELEC and those supplied by the concessionaires. In turn, this has led to significant tensions, particularly in concession areas bordering SENELEC's service areas. The high cost of service delivery in the concession areas is also a key challenge for the viability of the concessionaires. ERA estimates that in its concession area, grid extension costs twice as much as solar home system installations. Because the electricity uptake rate is much lower than expected (20 percent in the targeted villages instead of the forecast 70 percent), the actual cost of a grid connection per user is eight times more than a solar home system[50].

Other challenges include that SENELEC did not sign power purchase agreements (PPAs) with two of the *affermage* contract holders. Furthermore, the low electricity uptake rate was far lower than expected (e.g., ERA case 20% in the targeted villages instead of the forecast 70%), the actual cost of a grid connection per user is eight times more than a solar home system. Rather than leaving concessionaires free to choose technologies, a comprehensive least-cost electrification plan should form the basis of a national electrification strategy[51].

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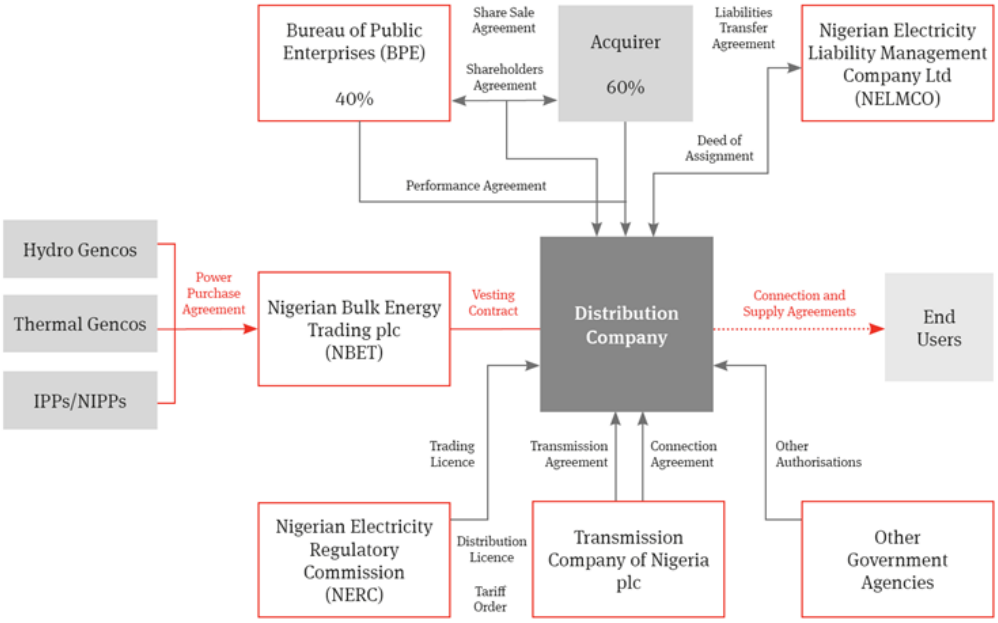
[50] http://documents.worldbank.org/curated/en/710071498161444599/pdf/116653-WP-PUBLIC-P150241-36p-Detailed-Case-Study-Senegal.pdf

[51] http://documents.worldbank.org/curated/en/710071498161444599/pdf/116653-WP-PUBLIC-P150241-36p-Detailed-Case-Study-Senegal.pdf

Annex 4: Privatisation cases

Nigeria



Source: Norton Rose Fulbright[52]

[52] https://www.insideafricalaw.com/publications/privatisation-of-distribution-companies-in-nigeria-project-profile