PRIVATE SECTOR PARTICIPATION IN AFRICAN GRID DEVELOPMENT

Grids 4 Africa

an initiative by

RES 4 AFRICA FOUNDATION

Private Sector Participation in African Grid Development

About Grids4Africa

Acknowledging the importance of electricity grids for achieving Africa's energy sector goals – access to reliable electricity and the incorporation of increasing amounts of renewable energy – the Grids4Africa initiative aims to raise awareness about the need for investments in grid infrastructure and support the creation of public-private partnerships to channel additional resources towards grid extension and reinforcement.

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Executive Summary

Africa's overarching development challenge is providing universal access to reliable, modern, affordable, and sustainable energy to all its citizens. Despite major strides in this area, the pace of progress is insufficient to meet SDG7 by 2030. Achieving this goal requires a substantial scale-up of not only public, but also private investments, as well as adequate planning and enabling policies to attract these investments. Relying on evidence from ten focus countries – Algeria, Ethiopia, Ghana, Kenya, Morocco, South Africa, Tanzania, Uganda, and Zambia – and beyond, this study lends additional support to arguments in favor of private sector participation in Africa's electricity grids as a means to accelerate progress towards the achievement of energy sector, as well as wider development goals.

Structural challenges persist in most African nations' power sectors. Electrification levels remain low, and the expansion of access risks being outpaced by the continent's population growth. Where electricity access is available, consumption is well below the global average and service quality tends to be sub-standard. Blackouts, brownouts, and load shedding are frequent and come at an immense socio-economic cost, putting additional pressure on already limited national budgets. The System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI) of our ten focus countries point to woefully inadequate service quality, with only Morocco scoring better than the global median. Four out of ten (Uganda, Ghana, Zambia, Tanzania) ranked in the bottom 10% globally. Inadequate measurement and reporting results in unavailable or unreliable data, complicating efforts to design relevant policy interventions.

The root causes of service quality issues are inadequacies related to the capacity and quality of electricity infrastructure and its management. Insufficient generation or an inability to scale generation up and down to meet demand peaks, inadequate capacity or flexibility in transmission and distribution networks, and/or breakdowns at power stations, transformers, or other equipment due to poor maintenance all contribute to the inefficiency and unreliability of electricity provision. The severity of the last two points is illustrated by data on system losses. Compared to a global average of 8.2%, transmission and distribution losses in our country sample range from 10% in South Africa to 29% in Ghana.

Infrastructural inadequacies are the result of a chronic lack of investments from financially strained public utilities. The primary evidence of poor financial performance is that electricity tariffs are largely not cost-reflective and utilities fail to collect revenues for a large share of electricity generated. This is reflected in staggeringly high quasi-fiscal deficits – the difference between the net revenue of an efficient utility and the net cash it collects – averaging 1.5% of GDP in the ten surveyed countries. This severely limits utilities' capacity to invest both in new equipment and in maintaining existing assets.

The absence of financial viability also acts as a barrier for much-needed private investments. Poor financial standing, low operational efficiency, and a lack of transparency make the incumbent utility a high-risk counterparty in the eyes of investors. Meanwhile, government subsidies to support the utility create market distortions which render the market segment unattractive to investors.

The issues of service quality, underinvestment, and financial sustainability create a vicious cycle for utilities. Low financial sustainability of utilities results in underinvestment in grid infrastructure, leading to poor service quality, which gives rise to a non-payment culture and pushes consumers to resort to self-generation. To compensate the financial shortfall of a smaller consumer base, utilities are faced with a need to increase tariffs, but higher tariffs (in combination with continued low service quality) lead to yet more consumers opting out of the grid, eventually resulting in the collapse of utilities.

Breaking this vicious cycle requires parallel efforts to restructure African power markets and extend private participation to all market segments. On the one hand, breaking up vertical integration between the generation, transmission, distribution, and retail segments will serve to reduce cross-subsidization and create separate, self-standing market segments in which market competition is made possible. On the other hand, opening the grids market segment to private sector participation can attract additional investments, improve overall sector performance, and decrease the cost of service thanks to increased competition.

There are important lessons learned from the generation segment, which has attracted growing public and private investments across the continent. The result of this inflow of investments has been a spectacular increase in installed RES capacity in all ten countries analyzed over the past decade. Total renewable energy capacity in the ten countries (excluding hydro) grew 17-fold over the past decade, from under 700 MW in 2009 to over 11.5 GW in 2019. There is no doubt that the declining cost of renewable technologies has been instrumental to this sharp increase, but enabling policies and well-structured auction schemes, notably South Africa's REIPPPP, provided the required impetus.

In contrast with generation, electricity grids in Africa have seen astoundingly little private investment. Out of the $41 bn of recorded private investments in the overall electricity sector (both clean and fossil) over the past decade, less than half a percent has been directed to grids. As a result of this underinvestment, renewable generation is starting to exceed the grid capacity in many countries. This creates a paradoxical situation where production gets curtailed, and the state finds itself paying for undelivered electricity even as vast parts of its population struggle with inadequate electricity access. Curtailment risk also erodes investor confidence over the medium- to long-term, and risks driving up renewable energy financing costs as instruments to hedge such risks do not come cheap.

Grids are therefore likely to become the real bottleneck in the development of African power sectors. Addressing that bottleneck will require a concerted effort of efficient planning, opening market access to private investors, creating feasible business models, and fixing the electricity tariff conundrum.

Currently, private sector participation in African grids is the exception rather than the rule, often due to prohibitive regulation. While all ten focus countries legally allow PSP in generation, the legal landscape is vastly different for networks. In the transmission segment, operations are typically run by one public company per country, with the exceptions of Kenya and Zambia. Distribution represents a middle ground, with seven countries allowing PSP in the segment, but only four implementing it.

Where private participation is possible, the few existing private operators are outperforming public utilities. Private distribution companies in our focus countries demonstrate better performance on technical (distribution losses), financial (lower debt-to-equity, greater net cash flows, greater after-tax profit), and commercial (bill collection rates) indicators. Inspiration can be drawn from successful a number of South American countries (e.g., Brazil, Colombia, Peru, Chile), which have succeeded in creating highly competitive electricity sectors and attracting private involvement along the entire value chain.

To mobilize the private sector, there is a need to implement a spate of structural reforms. Central to any power sector reform is the presence of a strong, financially, and politically independent regulator. Seven out of ten of the analyzed countries have a relatively strong and independent regulator and the regulators in remaining countries are either relatively young (Morocco), or financially but not politically independent (Algeria), or neither politically nor financially independent (Ethiopia). Over the past decades, the power sectors of several African countries have undergone significant transformations towards a more liberalized model. Of our ten sample countries, three have fully unbundled their power sectors, two have made some progress towards unbundling, and five retain a vertically integrated structure.

Private sector participation in grids can take many forms, with varying scope, duration, and risk sharing characteristics. In the lightest forms of private participation, service and management contracts, private entities simply provide a good or service to the public utility or take responsibility for some aspects of utility management and are remunerated with a fixed fee. Leases and concessions represent more complex arrangements whereby private utilities take full responsibility for asset operation – in the case of concessions, also capital investments – and are remunerated through tariff collection. Finally, partial or full divestiture and merchant projects are the only indefinite forms of private participation, with the private sector owning a share or the entirety of a utility.

Realizing the full potential of private sector participation requires regulatory reform. Indeed, when making investment decisions, private investors and financiers place great emphasis on the regulatory context. Beyond a competitive market structure and the presence of an independent regulator, private investors look for markets with tariff regulation that guarantees adequate remuneration.

In summary, private sector participation offers a potential solution to the structural challenges persistent in many African power sectors. African governments have the opportunity to access and benefit from private financing, technology, and expertise. So far, private involvement in grids has had a limited track record with differing levels of success. However, our analysis of ten sample countries has shown that, overall, private utilities exhibit superior performance in technical, commercial, and financial indicators to their public counterparts. Although not a prerequisite for all private participation, unbundling and liberalization are indispensable for unlocking the full benefits of private involvement. However, an enabling regulatory environment and a supportive, ambitious, and committed government are indispensable to the success of any form of private involvement

Introduction

Achieving Sustainable Development Goal 7 (SDG7) is crucial for unlocking wider development progress in Africa. As such, it has attracted substantial efforts from a range of local and international stakeholders over the past decade. Considering the indispensable role of transmission and distribution grids in providing access to reliable electricity and incorporating increasing shares of renewable generation, the importance of investing in grid expansion and improvement cannot be overstated. A failure to develop grids will stifle efforts to accomplish SDG7 and slow the transition towards a renewables-based power system.

Yet Africa's electricity grids have received little attention thus far. In pursuit of a sustainable electricity supply, governments, businesses, and development partners have scaled up support for and investments into renewable energy generation capacity on the continent, which increased by 50% over the past decade.[1] However, these efforts have not been matched by investments in grid infrastructure, the underdevelopment of which may soon become a limiting factor for the deployment of renewable technologies. This then leaves governments paying for undelivered electricity even as the majority of the population struggles with inadequate electricity access.

Indeed roughly 57% of Africans do not have a reliable electricity connection, despite major strides in electrification in the last thirty years.[2] Blackouts, brownouts, and load shedding are almost daily occurrences in much of the African continent, partly due to outdated and underperforming grid infrastructure requiring burdensome upkeep. Utilities are unable to balance high operation and maintenance costs with low revenues, resulting in financially unsustainable business models. Globally, private utilities have been shown to outperform public utilities, bringing valuable technical, and financial contributions. As such, their involvement in African transmission and distribution sectors could significantly bolster grid development.

This study puts the spotlight on the current landscape of electricity transmission and distribution using evidence from 10 focus countries – Algeria, Ethiopia, Ghana, Kenya, Morocco, South Africa, Tanzania, Uganda, and Zambia, as well as individual examples from beyond. The study aims to highlight the current challenges facing African grids and explore the potential for the private sector to contribute to overcoming them, so that all Africans may benefit from affordable, reliable, and sustainable electricity.

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[1] IEA Data and Statistics (2021) For additional information see : https://www.iea.org/data-and-statistics/data-browser?country=WEOAFRICA&fuel=Electricity%20and%20heat&indicator=ElecGenByFuel

[2] Afrobarometer (2019) Progress toward 'Reliable Energy for All' stalls across Africa, Afrobarometer survey finds.

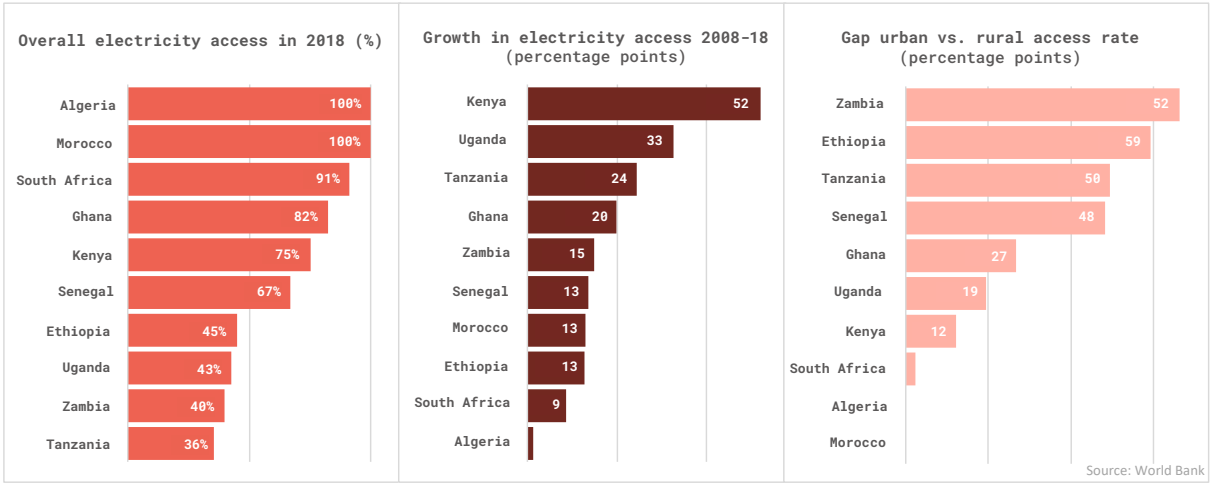
1.0 The Challenges: access, consumption, quality

1.1 Electricity access has been improving, but remains insufficient

Africa's overarching development challenge is providing universal access to reliable, modern, affordable, and sustainable energy to all its citizens. Over the past two decades, several countries made major strides in expanding access to electricity, but electrification levels remain very low even compared to countries with similar development outcomes in other global regions. Furthermore, Africa's high population growth rate risks outpacing current and planned electrification efforts by African governments.[3]

This issue does not apply evenly across the ten countries analyzed (see Figure 1). North African countries, including Algeria and Morocco, reached almost universal access to electricity by 2018. On the other hand, many sub-Saharan African countries have some of the world's lowest electrification rates: as of 2018, less than 45% of Ugandans, Zambians and Tanzanians had an electricity connection. Success stories such as Kenya's remarkable 52 percentage point increase between 2008 and 2018 demonstrate that turning the tide is possible, when adequate planning and investments are deployed.

Figure 1: Electricity access rates



Large urban-rural disparities are as acute of a problem as overall energy access. In 2018, the gap in electricity access between urban and rural population stood at 66% in Zambia, 59% in Ethiopia and 50% in Tanzania. Zambia is a striking example of well-electrified cities versus rural areas left in the dark (access rates are 77% for urban and 11% for rural). Ensuring access for urban populations via on-grid connection tends to be less expensive, on average, than finding affordable electrification solutions for remote rural areas and small cities not reached by the national grid. On the other hand, recent trends show that expanding access in urban areas is also becoming increasingly challenging, particularly in the case of populations residing in vast informal settlements that are unlikely to be attractive customers for utilities.[4]

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[3] IEA (2019) Africa Energy Outlook 2019.
[4] International Bank for Reconstruction and Development/The World Bank (2020), Tracking SDG7, The Energy Progress Report 2020

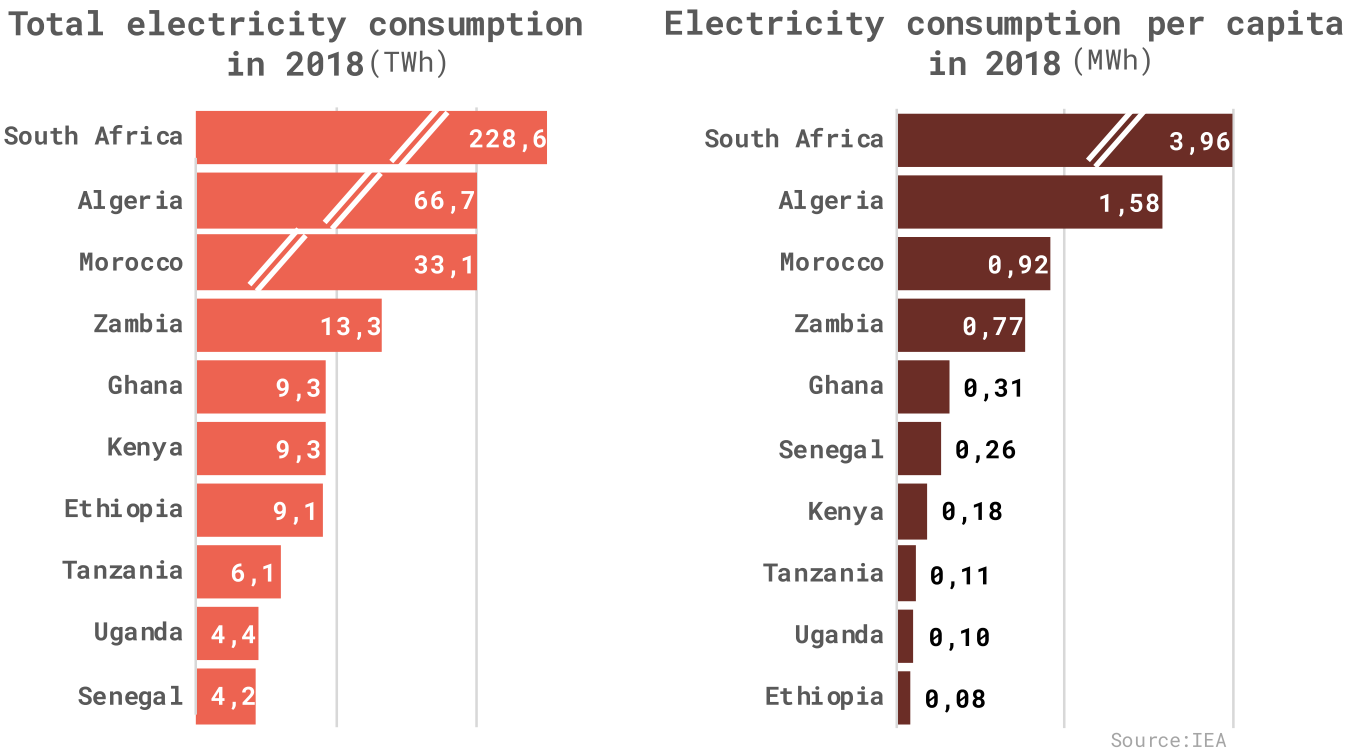
Overall, the past years indicate that progress is possible, but reaching full electricity access in both urban and rural areas requires a major scale up of investments, adequate planning, and enabling policies needed to attract the scale of public and private investments needed.

1.2 Even those who do have electricity tend to use very little of it

Similarly to electricity access, electricity consumption levels vary significantly across our selected African countries. South Africa, Algeria and Morocco emerge as three regional champions, with the first two consuming more electricity alone than the other seven countries under analysis combined. At the other end of the spectrum, countries such as Tanzania, Uganda and Senegal have relatively low total electricity consumption, even though all three have seen an increase in their consumption levels over the 2010-2018 period.

What is more telling is the fact that despite the existing differences between countries, the average per capita consumption is lower in Africa than in all other regions of the world.[5] With the exception of South Africa and Algeria, which have a far higher consumption per capita due to a large industrial sector, all other nations under analysis consume less per capita than, for instance, the regional

Figure 2: Electricity consumption

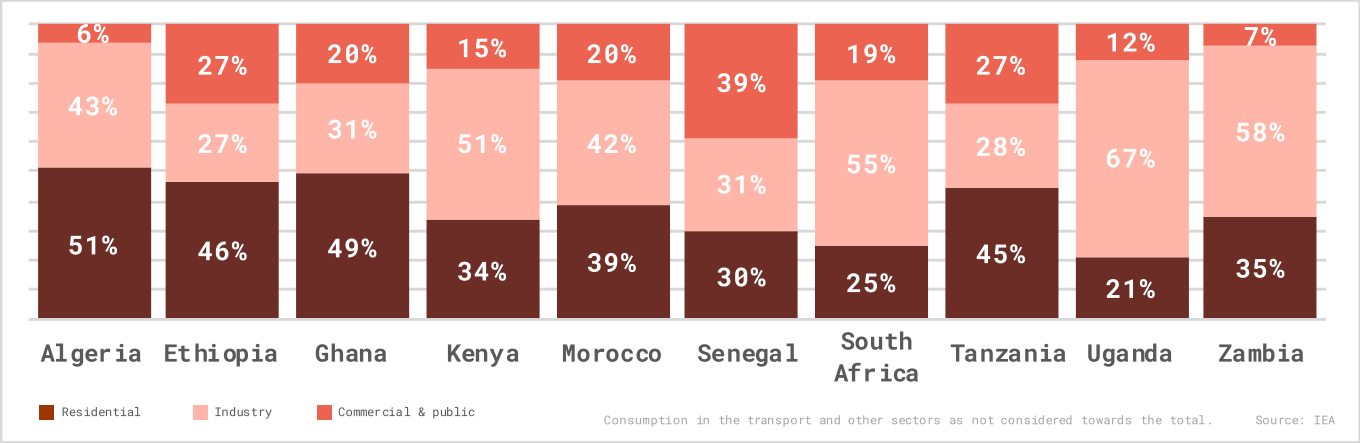


[5] Andrew Scott (2015) Building Electricity Supplies in Africa for Growth and Universal Access, The New Climate Economy.

average in Asia[6] (1,1 MWh) and Central and South America (2,1 MWh)[7]. This suggests that even when people have access to electricity, they tend to use very little of it.

In terms of electricity consumption by sector, data for 2018 show that industrial consumption accounted for more than 50% of the total in four countries out of ten, namely Zambia, Uganda, South Africa, and Kenya. Conversely, industrial electricity consumption stood at less than 30% of total consumption in both Ethiopia and Tanzania.

Figure 3: Electricity consumption by sector in 2018 (% share of total)



1.3 Where electricity is provided, the service quality is remarkably low

The poor quality of the electric service in many African countries is arguably as acute of a problem as low electricity access rates. Frequent outages, load shedding, brownouts and blackouts come at an immense economic, environmental and health cost. When grid electricity supply fails, workarounds are expensive: generator-based power in sub-Saharan Africa is estimated to cost double or more that of grid electricity. Back-up generators, typically run on fossil fuels, fill neighborhoods with major noise disturbances, and the cost required to install, fuel, and maintain generators imposes significant economic burden on businesses and households. Above all, the CO2 and fine particulate matter emissions of generators contribute to climate change and compromise human health, especially considering they are often used in close proximity to homes and residential areas.

The quantification is usually done by two indices measuring the frequency and duration of power outages, the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). Yet, out of 19 surveyed African utilities which have a relevant T&D component, only four (21%) publicly report their SAIDI and SAIFI figures. A viable alternative data source is the World Bank, which reports two relevant metrics:

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[6] The Asia figure does not include China
[7] IEA (2021) Data and Statistics. For additional information see: https://www.iea.org/data-and-statistics/data-browser?country=WEOEUR&fuel=Energy%20consumption&indicator=ElecConsPerCapita
[8] IFC (2019) The Dirty Footprint of the Broken Grid.

- Annual SAIDI and SAIFI figures for all of our ten countries apart from Ethiopia.
- Annual Enterprise Survey, which reports the perception of businesses on a range of indicators, including quality of electricity service, for all ten countries apart from Algeria.

The World Bank SAIDI and SAIFI figures point to woefully inadequate service quality in our ten analyzed countries (see Figure 4). In 2019, only Morocco scored above the global median (2,7 for SAIDI and 2,2 for SAIFI). Uganda, Ghana, Zambia, and Tanzania ranked in the global bottom 10% in terms of either duration or frequency of service interruptions. Even South Africa, categorized by the World Bank as an upper middle-income country, occupied the 23rd worst position globally.

Figure 4: Electricity service quality overview (SAIDI and SAIFI)

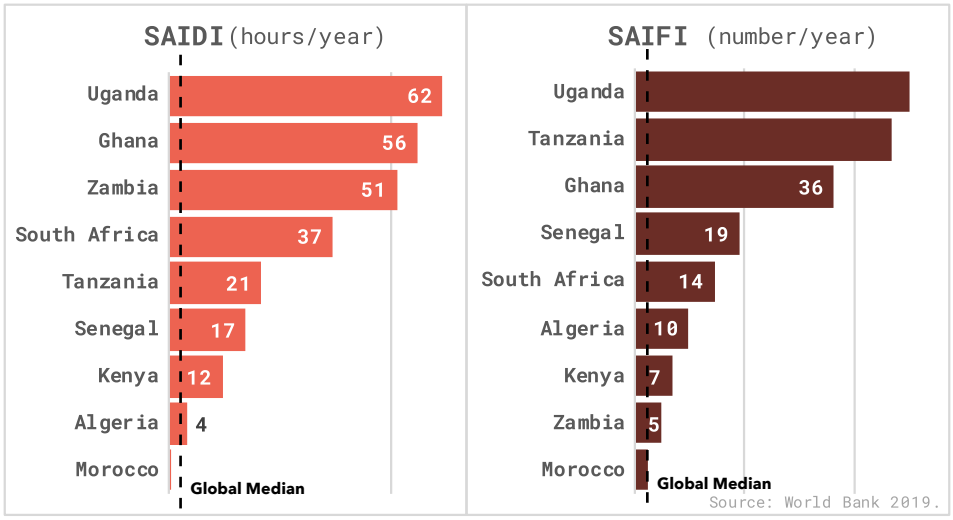
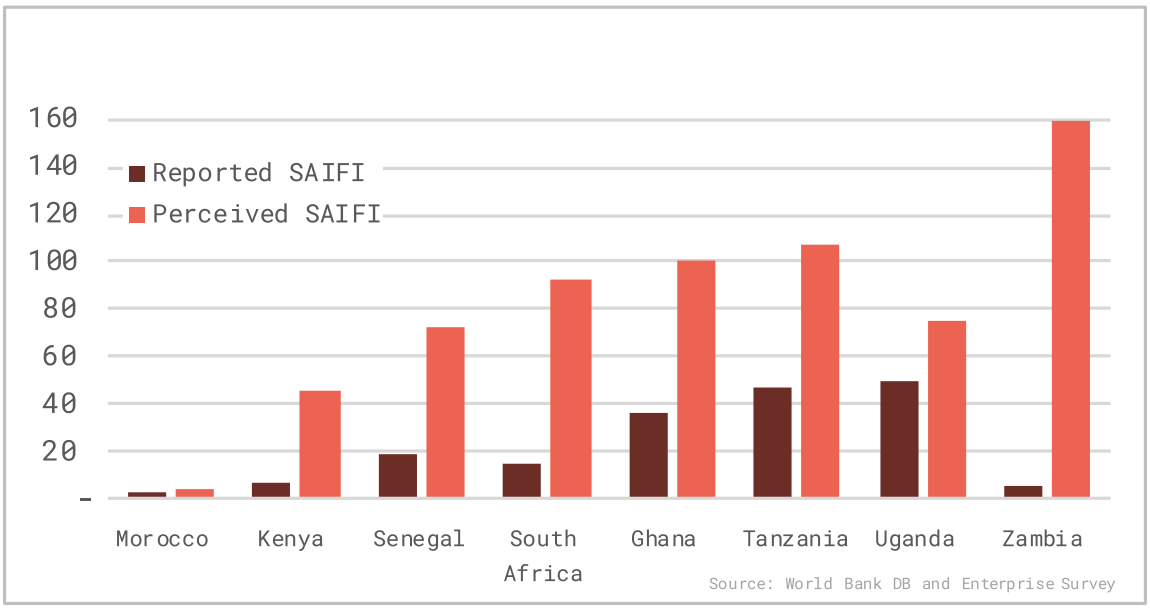


Figure 5: Reported vs perceived SAIFI



It is worth noting that the real quality of service may be even lower than reported by the SAIDI and SAIFI World Bank figures. An alternative data source, the World Bank Enterprise Survey, reports figures on the number of electrical outages that firms experience in a typical month, and figures suggest the experienced (or perceived) SAIFI is many times larger than the reported one (see Figure 5). In the extreme case of Zambia, users experienced a SAIFI that is 33 times larger than the reported one. On the other hand, Uganda, which stands out as the worst performer in official World Bank SAIDI and SAIFI figures, may simply be the least bad at reporting its figures as the delta between the reported and perceived SAIFI is relatively narrow. The differences between reported and perceived figures are largely due to reporting methodology, as utilities tend to consider a high time threshold before a given outage is reported as a SAIFI. This raises the issue of data availability and reliability, where inadequate reporting is complicating efforts to design facts-driven policy interventions.

2.0 The causes: underinvestment and low financial sustainability of utilities

2.1 African grids are crumbling amid structural underinvestment

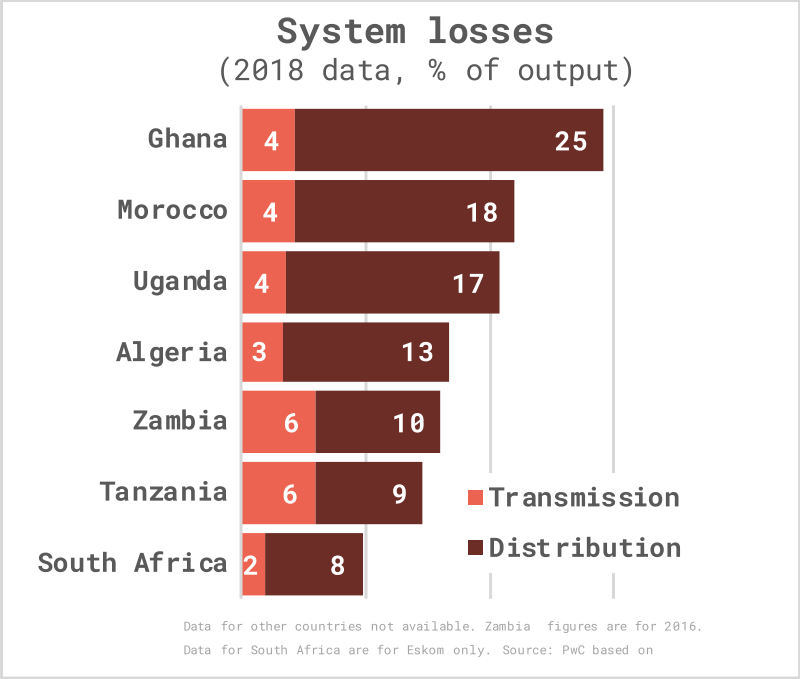
Africa's electricity conundrum has many causes, and different countries present specific problems. Overall, it can be argued that the root cause of reliability and service quality issues is related to the capacity and quality of electricity systems, where inadequacies can be a result of:

- Insufficient generation or inability to scale generation up and down to meet demand peaks;
- T&D networks having inadequate capacity or flexibility to deliver generated power to end users;
- Breakdowns at power stations, T&D lines, transformers, and other equipment due to poor maintenance.

The severity of the last two points is illustrated by data on system losses. Compared to a global average of 8.2%, transmission and distribution losses in our country sample range from 10% in South Africa to 29% in Ghana (see Figure 6). These figures are composed of:

- Technical losses, i.e., energy converted to heat in power lines and transformers resulting from laws of physics, losses due to cable theft and equipment damage, etc.
- Non-technical losses, i.e., energy generated, delivered, and consumed but not recorded by a meter, due to illegal connections, meter tampering, inefficient bill collection etc.

Figure 6: Transmission & Distribution losses



None of the surveyed utilities report disaggregated T&D figures for technical and non-technical losses. Yet what transpires is that, whether for technical or non-technical reasons, utilities tend not to collect revenues for an immense share of the electricity generated. This in turn reduces their financial viability and their capacity to invest both in new equipment and in maintaining existing assets.

The scale of underinvestment is difficult to quantify in a systematic manner. The volume of investment required are typically quantified by the regulator in terms of newly built infrastructure and maintenance of existing assets, whereby:

- New infrastructure: investment requirements are driven by least-cost development plans, where the regulator, as part of its tariff setting and on the basis of previously established grid plans, specifies a CAPEX figure which utilities are allowed to spend towards building new regulated assets.
- Existing infrastructure: investment requirements are driven by a target share of revenue, set by the regulator, which is to be spent on maintenance of existing regulated assets.

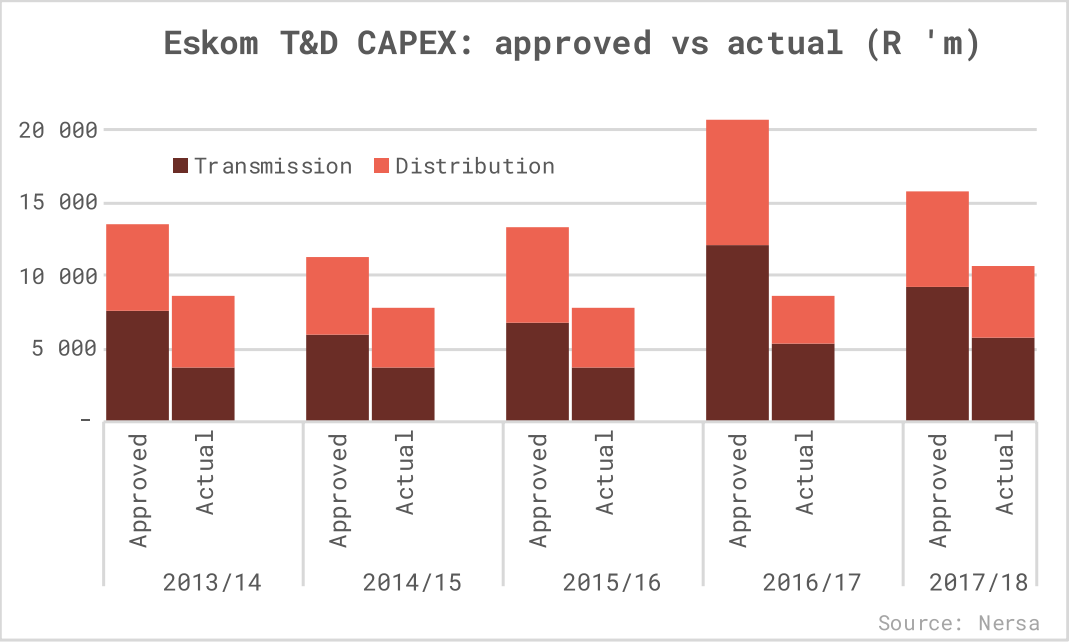
For both of the above investment indicators, systematic tracking is made complex by the fact that, in the rare cases that utilities do report on CAPEX and/or maintenance figures, they tend not to differentiate between expenses for regulated vs. non-regulated assets. By way of example, renovation work on a utilities' office will be considered as CAPEX in the utility's audited financial statements, but it does not count towards regulated assets CAPEX.

In a general sense, if strapped for cash, utilities tend to prioritize investments in newbuilds rather than on maintaining existing assets. This is driven by two factors: first, attracting external finance is done more easily for newbuilds, and second, building new assets tends to be more politically attractive than "simply" maintaining assets that exist already. Yet even the option of attracting external finance for grid infrastructure has had a limited track record, as investors overwhelmingly favor the generation segment. Indeed, the World Bank reports out of $41bn of private investments in the African electricity sector over 2010-20, only $141m, equivalent to 0.3%, was dedicated to T&D infrastructure. Low private investments in the grid are closely related to regulatory and market structure issues, where market power of incumbents has stood in the way of the creation of business models conducive to private investments.

Box 1: Underinvestment in Eskom's transmission and distribution assets

South Africa is a case of relatively sound data availability and transparent reporting. The regulator Nersa makes available on its website all decisions concerning its tariff revisions, which also provide a detailed point-by-point analysis of Eskom's tariff application and the motives for its adoption or rejection. In its 2018 Decision and Reasons for Decision relative to: Eskom's revenue application for 2018/19, Nersa notes that Eskom has been exceeding the allowed RAB CAPEX in the generation segment amid what Nersa characterized as an imprudent overspend and inefficient cost planning. The over-expenditure in the generation segment over the 5-year regulatory period 2013-2018 amounted to 102%, as Eskom capital has been prioritized on generation infrastructure to complete big Medupi and Kusile new builds as well as improve energy availability on the ageing coal fleet.

On the other hand, the transmission and distribution segment saw a RAB CAPEX under-spend of 47% and 35% respectively. Such underspending, in the face of growing RES share in the generation mix, is resulting with constraints in the grid infrastructure which are expected to get incrementally more acute. Among municipal distributors as well, large backlogs in investment in the ageing distribution infrastructure is evident as municipalities lack capital to invest in the distribution infrastructure.



2.2 Many utilities run financially unsustainable business models

Another key factor contributing to poor service quality, underinvestment, and overall slow progress in electrifying sub-Saharan Africa is the poor financial sustainability of its utilities. Being financially sustainable refers to the ability of the utility to sell electricity at a rate that consistently generates enough revenues to cover all of its expenses (both short and long-term). The business model of many African utilities is unsustainable on two grounds:

- Electricity tariffs tend to be set too low, at levels that do not guarantee the recovery of the true cost of producing and selling electricity – including all operating expenses, debt service and reserve funds for equipment replacement and future improvements.
- Capital assets are not managed with a view to the future, as infrastructure development plans are not followed through and insufficient funds are dedicated for efficiently preserving and/or replacing critical infrastructure.

The two factors are interrelated. Being cash-strapped pushes utilities to let their assets fall into disrepair and finding alternative sources of funding on capital markets (e.g., by borrowing) tends to be expensive as low creditworthiness drives up interest rates. Independent private financing could provide a source of additional finance. But the poor financial viability of incumbents also tends to act as a barrier to private investments, via two distinct mechanisms:

- Where incumbents act as intermediaries, e.g. offtakers in a PPA contract or counterparts in a distribution service contract, the low financial sustainability gives rise to high counterparty risk.
- Even where incumbents do not act as intermediaries (e.g. a private entity is granted a distribution license in a given territory), the range of implicit and explicit subsides that incumbents receive creates market distortions. These distortions tend to render the market segment unattractive to private investors.

In a fundamental sense, utilities are able to carry on their unsustainable business model only thanks to public subsidies, and these subsidies compromise a level playing field where incumbents and private sector actors compete equally.

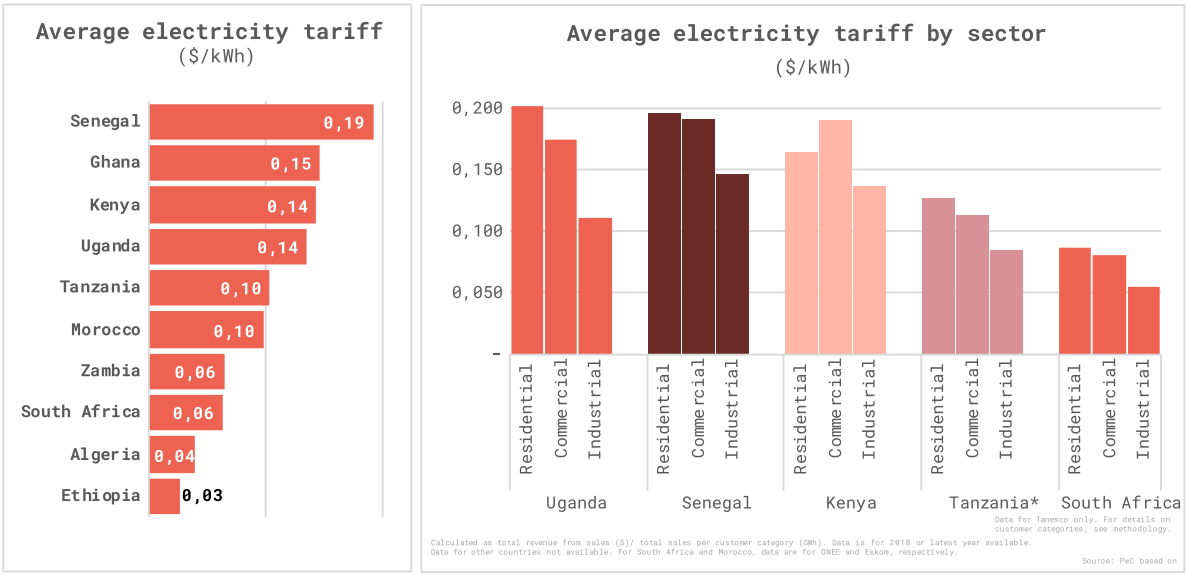
The primary evidence of the low financial sustainability of African utilities is that in many countries, tariffs are largely not cost-reflective. Quantifying the cost-reflectiveness of tariffs is made difficult by the paucity of publicly accessible cost-recovery data for distribution utilities. A World Bank report from 2016, Making Power Affordable for Africa and Viable for Its Utilities, made a seminal contribution by measuring African utilities' hidden costs. It found that of 39 sub-Saharan African countries examined, only two countries (Seychelles and Uganda) were fully recovering their utility operational and capital costs. Quasi-fiscal deficits – the difference between the net revenue of an efficient utility and the net cash it collects – were found to average a staggering 1.5% of gross domestic product (GDP).[9]

[9] Masami Kojima & Chris Trimble (2016) Making Power Affordable for Africa and Viable for Its Utilities, World Bank ESMAP

Figure 7 provides a view of average electricity tariff levels in the ten countries analyzed, with significant regional variations ranging from a low of 0,03 $/kWh in Ethiopia to 0,196 $/kWh in Senegal. Setting tariffs below cost-recovery levels tends to be presented as a pro-poor measure favoring electricity affordability. Yet the range of implicit and explicit subsidies provided to failing utilities are in any case shifted onto public balance sheets, meaning that in the long run, final users remain the ones footing the bill.

Overstaffing is another oft-cited component of financial unsustainability of African utilities. State-owned entities tend to be considered as social safety nets or employers of last resort, providing jobs for vast swathes of the population. Yet this practice is a source of immense operational inefficiencies, as utilities are burdened with vast staffing expenses while at the same time lacking key competences needed for its efficient and modern operation. The practice also has detrimental societal effects as it tends to perpetuate clientelist networks, nepotism and corruption and reduces democratic accountability.

Figure 7: Average electricity tariffs



It is worth noting that data on overstaffing (measured by the ratio of customers to employee, where a higher figure is better) suggests that not all state-owned vertically integrated utilities are born the same. In the extreme case of Zambia, one employee accounts for only 137 customers. In Morocco's ONEE, on the other hand, an employee accounts for nearly five times as many customers (see Figure 8). This large divergence between entities which nominally could be considered the same (vertically integrated, state owned) suggests that with the right incentives, operational efficiencies are possible also among public utilities.

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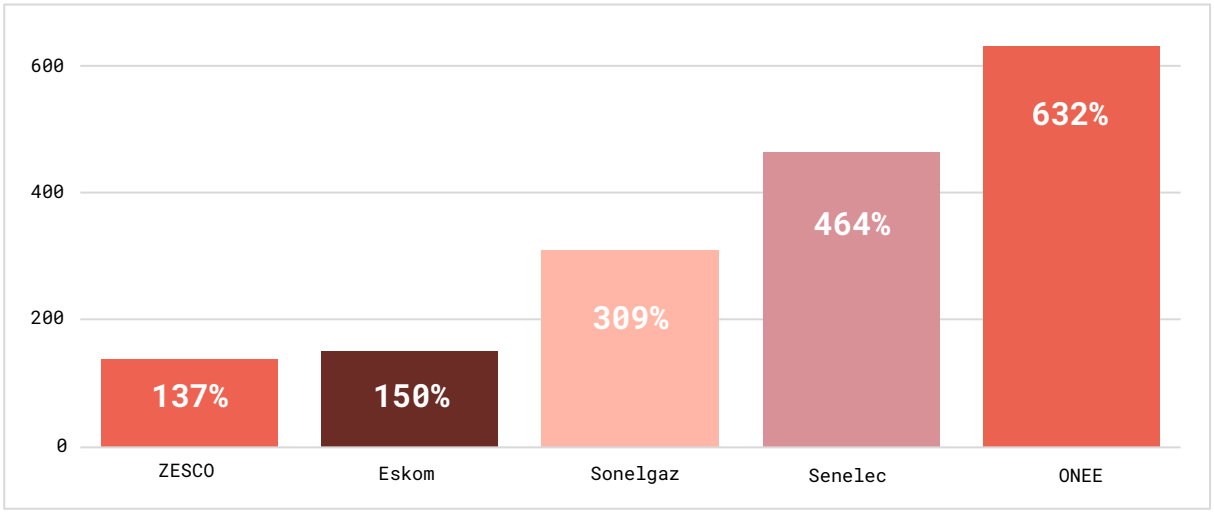
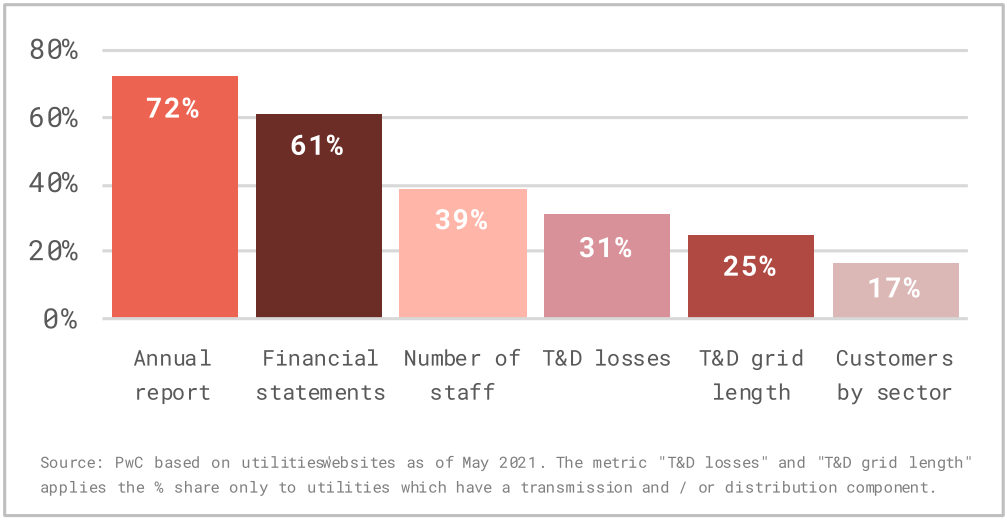
Figure 8: Overstaffing in selected vertically integrated utilities



The difficulty of quantifying information on financial sustainability is driven in the first place by the absence of clear, consistent, reliable, transparent, and publicly accessible financial, accounting, and corporate reporting (see Figure 9). Indeed, out of 18 state-owned utilities surveyed in this study, only 72% have at least one annual report accessible on their website. Out of these, only 28% are more recent than two years, and only 61% include audited financial statements which would allow insight on the vitally important financial aspects of the business. When it comes to reporting data on the physical aspects of the business, only 31% of utilities operating in the transmission and distribution segment report system losses, and only 25% provide consistent data on network length. These figures overestimate the real availability of data, because many utilities only have a few dated reports available, typically prepared as part of a donor package, which are then not replicated in a consistent manner from one year to the next.

Figure 9: Share of African utilities reporting on selected metrics



Source: PwC based on utilitieswebsites as of May 2021. The metric "T&D losses" and "T&D grid length" applies the % share only to utilities which have a transmission and / or distribution component.

The low availability of data gives rise to two sets of problems:

- First, it precludes the possibility of setting up informed and evidence-based policy actions able to tackle the underlying issues. In the absence of sound data, any policy action risks being misguided or tackling the wrong problem.
- Second, the low data transparency erodes the scope for public scrutiny on an issue which is of fundamental societal interest. Perpetual cycles of government bailouts and systemic subsidies are fundamentally paid for by citizens, either via electricity bills or taxes, and the low transparency of data points to fundamental issues with democratic accountability.

The patchy data which does happen to be available indicates that out of 14 state-owned utilities analyzed, 8 were posting an after-tax loss while 5 were making a loss even just on their operations (see Table 1). As some of the analyzed utilities are vertically integrated, pin-pointing the root cause of the losses and inefficiencies is unfortunately difficult. This is further complicated by cross-subsidies between various integrated utility services in cases where the electric utility is integrated with water and/or gas (e.g., Morocco and Algeria). At any rate, the financial shortfall of lossmaking utilities is shifted onto government budgets and taxpayers, either directly through bailouts or indirectly through implicit transfers and subsidies.

Moreover, these figures present an overly positive story, and the real losses are likely to be much higher. In fact, the figures only refer to explicit financial statements of utilities, and do not take into the direct subsidy forms which many utilities receive, and which are already counted on the balance sheet. Examples of such forms of subsidies may include:

- Government takeover of utility debt (e.g. ZESCO)[10]
- Direct government subsidy transfer to balance sheet (e.g. ECG[11], Senelec[12])

All of the above interventions artificially improve the balance sheet of utilities, and further obfuscate the evidence on the real extent of their losses.

Table 1: Profitability of selected state-owned utilties

Country	Utility	Operating profit/loss	Loss/profit before tax
Morocco	ONEE	✓	✗
Algeria	Sonelgaz	✗	✗
Senegal	Senelec	✓	✓
Ghana	GRIDCo	✓	✓
	VRA	✓	✗
	ECG	✗	✗
Ethiopia	EEU	no data	no data
Kenya	KPLC	✓	
	KETRACO	✓	✓
Uganda	UEDCL	no data	✓
	UETCL	✗	✗
Tanzania	TANESCO	✓	✓
Zambia	ZESCO	✗	✗
South Africa	Eskom	✗	✗

*Data is for 2018 or the latest year available.

2.3 The risk: utility vicious cycle

A number of issues outlined above are tied together in a vicious cycle, whereby:

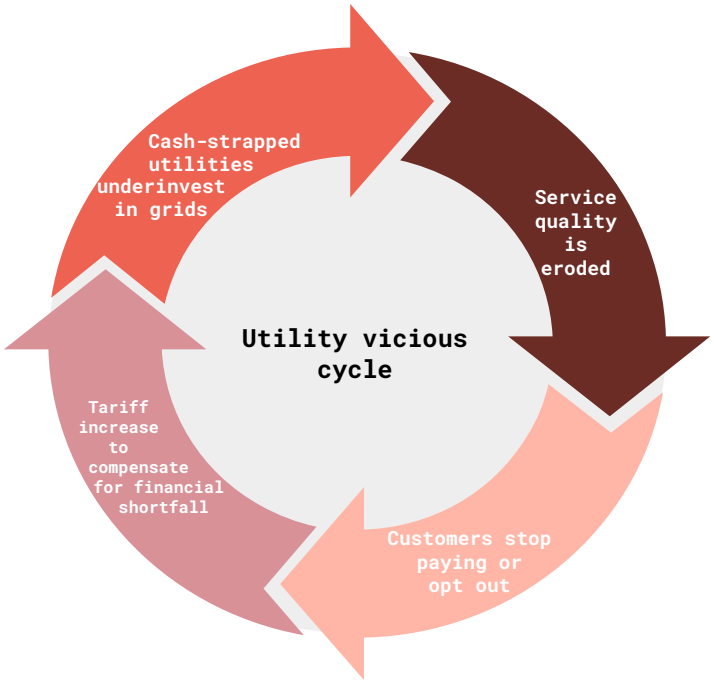
- Low financial sustainability of utilities leads to underinvestment in grids infrastructure;
- Structural underinvestment in grids gives rise to poor service quality in the form of frequent blackouts, brownouts or scheduled load shedding;
- The low service quality gives rise to a non-payment culture: at a certain point the willingness to pay threshold is breached, and customers either stop paying for the

[10] African Energy, Zambia Government takes on ZESCO debt 11/02/2021
[11] ECG (2018), Financial Report.
[12] CRSE (2020), Décision n°2020-56 relative aux conditions tarifaires de Senelec pour la période 2020-2022

electricity service or choose to pursue alternative sources to meet their demand (e.g. self-generation);

- Utilities are faced with a need to increase tariffs in order to compensate the financial shortfall of a smaller consumer base;
- Higher tariffs (in combination with continued low service quality) in turn lead to yet more consumers opting out of the grid, eventually leading to the collapse of utilities.

Figure 10: Utility Vicious Cycle



Additionally, the frequently seen electricity market liberalization approach, whereby the generation segment is open to private investments while the incumbents remains the single buyer and is fully responsible for grid infrastructure, can be seen as structurally unsustainable. In order to attract IPPs into the generation segment and reduce the risk profile of their investments, IPPs tend to be granted rather generous PPA terms. These generous PPAs in turn undermine the incumbent's financial returns and deprive them of an ability to invest in grid infrastructure.

To break this vicious cycle, utilities and policy makers need to reconsider two elements:

- Breaking up vertical integration between the generation, transmission, distribution and retail segments, in order to reduce cross-subsidization and create separate, self-standing market segments in which market competition is made possible. Competition can provide efficiencies and drive the creation of new competitive business models
- Extending private sector participation to the grids component of the electricity market, to reduce structural imbalances, further promote competition, and maximize returns from new business models.

3.0 A potential solution: private sector participation

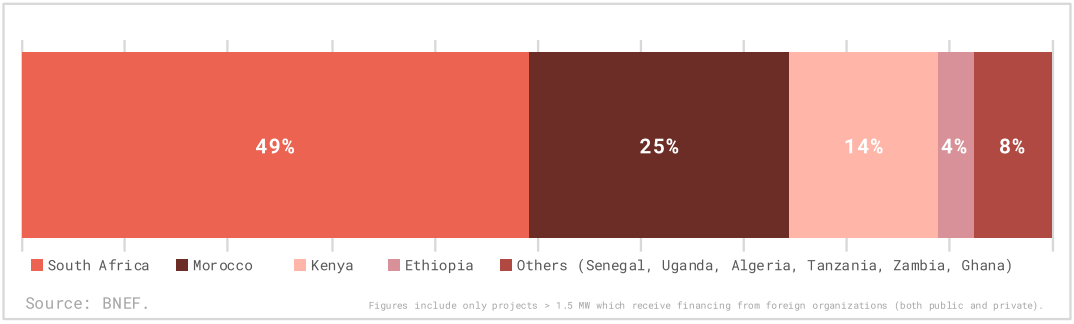
3.1 Private sector participation in the generation segment provides lessons learned

Many of the issues the African utility sector is facing are related to a structural underinvestment of own resources and a weak ability to attract external providers of finance. But there are notable lessons learned in some areas: in the past decade, the generation segment has attracted growing public and private investments, resulting in a notable increase in renewable generation capacity.

Over the 2010-2019 period, Bloomberg New Energy Finance reports that more than USD 39 billion was invested in renewable energy projects in the ten countries under analysis, referring to foreign investments i.e., coming from organizations based outside of the recipient country. This figure includes disclosed asset finance deals for RES projects larger than 1.5 MW, and accounts for investments from both public and private organizations.[13]

Some countries have proven to be much better at attracting and mobilizing investments (both public and private) than others: South Africa absorbed nearly half of the overall 39 billion over the past decade, while Morocco accounted for ca. 25% of the remaining investments in clean power generation projects. On the other hand, Ghana, Zambia, Tanzania, Algeria, Uganda, and Senegal took less than 2% each out of the total money spent in RES projects in the countries under analysis (see Figure 11).

Figure 11: Investments in clean electricity generation over 201-19 (% share of total)



Some of this disparity is certainly explained by the relative size of each country's electricity system. But equally important considerations are the presence of enabling RES policies and the overall market openness to private investments. South Africa and Morocco are two cases in point, as the

[13] Bloomberg NEF (2020) Climatescope 2020

two countries set up effective auction schemes and opened the market for wheeling and corporate PPAs, all of which had a pivotal role in attracting independent power producers (IPPs) and a diverse range of financing streams.

The result of this inflow of investments has been a spectacular increase in installed RES capacity in all ten countries analyzed. Total renewable energy capacity in the ten countries analyzed (excluding hydro) grew 17-fold over the past decade, from under 700 MW in 2009 to over 11.5 GW in 2019 (see Figure 12)[14]. There is no doubt that the declining cost of renewable technologies, especially solar PV, has been instrumental to this sharp increase. But enabling policies and well-structured auction schemes, notably South Africa's REIPPPP, provided the required impetus.

Figure 12: Installed RES capacity

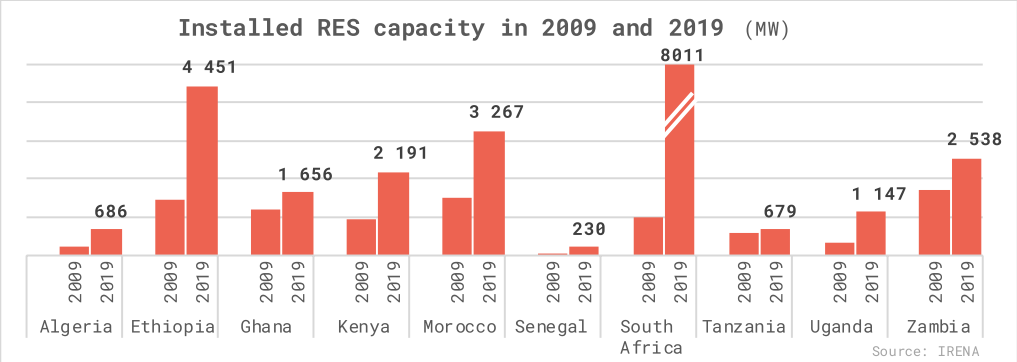
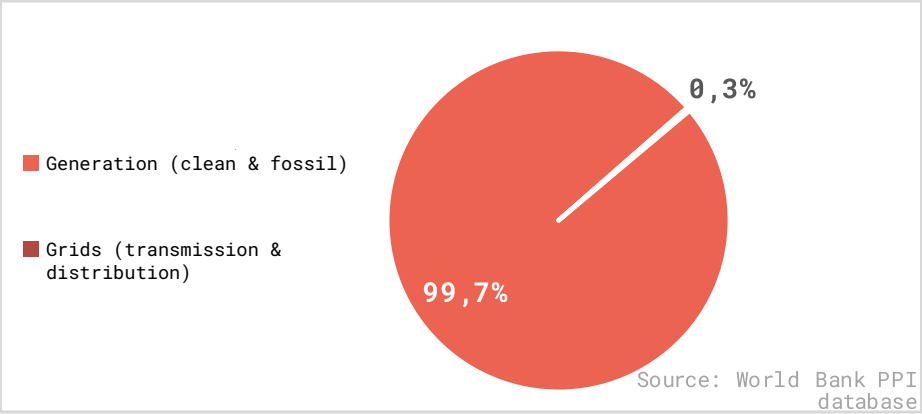


Figure 13: Private investments in the electricity sector over 2010-20 (% share of total)



Against this backdrop, the picture changes drastically for the grids segment. Out of the $41 bn of recorded private investments in the overall electricity sector (both clean and fossil) over the past decade, less than half a percent has been directed to grids (see Figure 13). To the difference of a number of developing countries in South America and Southeast Asia, which have successfully experimented with attracting private investments and participation in the grids sector, private capital flows into African transmission & distribution sectors (T&D) is virtually zero.

[14] IRENA (2020), Scaling Up Renewable Energy Deployment in Africa.

Investment in grids is typically expected to come from state-owned utilities. But in many countries, investments have been held back by debt-laden and cash strapped utilities which, having to prioritize the scarce financial resources available, have tended to leave the grids segment in crumbles.

As a result of this underinvestment, in many countries renewable generation is starting to exceed the grid capacity. This creates a paradoxical situation where production gets curtailed, and the state (and its taxpayers) finds itself paying for undelivered electricity even as vast parts of its population struggle with inadequate electricity access. Curtailment risk also erodes investor confidence over the medium- to long-term, and risks driving up the RES financing costs as instruments to hedge such risk do not come cheap.

Grids are therefore likely to become the real bottleneck in Africa's electrification effort. Addressing that bottleneck will require a concerted effort of efficient planning, opening market access to private investors, creating feasible business models, and fixing the electricity tariff conundrum.

Box 2: The opportunities and challenges of digital solutions

Digitalization of electricity grids can provide part of the solution to crumbling African grids, both in terms of hardware (the wire and grid technology) as well as software (such as system monitoring, data driven automation, etc.). Although the initial cost of digitizing the grid is often higher than repairing old equipment, the costs are recovered over the long term. Grids in many African countries are made up of dated equipment which is not easily replaced, as manufacturers discontinue equipment. Even where replacements are possible, there may be issues of interoperability between older and newer models. As much of the energy infrastructure reached the end of its lifespan, an opportunity is presenting itself for African utilities to leap-frog to a new model, as it has done in telecoms.

While fully digitizing the grid may sound futuristic for many African utilities, below is a sample of quick-win digitalization solutions which could help relieve a series of electricity sector issues:

- Fault Location & System Restoration (FLSR) linked to Geographic Information Systems can detect outages real-time, isolate them and then automatically restore the service.
- Energy data collection and monitoring systems can conserve energy through voltage reduction, peak demand management, and provide support for microgrids. At higher degrees of sophistication, these can be driven by machine-learning functionalities able to automate the optimization of grid performance.
- Pre-paid metering reduces the costs of metering and billing, eliminates the issue of non-payment or inadequate bill collection, and improves the experience of lower-income customers for whom incremental pay-as-you-go schemes may be easier to shoulder then lump-sum payments at the end of the month. Pre-paid metering also eliminates the politically delicate issue of disconnecting non-paying users.

- Smart metering similarly reduces the costs of metering and provides an enhanced user experience. It also enables the utility to set up demand response tariffs with a potential to reduce peak loads and stimulate energy efficiency.
- Digital payment mechanisms and customer interfaces provide an enhanced user experience and may stimulate higher bill payment, considering the ubiquity of mobile money across African countries.

Out of the above solutions, the one most prevalently adopted is pre-paid meters. They require users to purchase credit up-front and load it into the electricity meter, which then displays the amount of kWh the user has at disposal. Eight out of ten analyzed countries have rolled them out to all or nearly all residential customers, the exceptions being Morocco and Algeria, where a relatively mature electricity market likely lends itself less to pre-paid solutions (see Table 2). They have been introduced as a cost-efficient means for utilities to stem non-payment, reduce the costs of metering and billing, and provide users with a better predictability of their costs.

There have also been some steps towards introducing smart meters, particularly for industrial users for the purpose of introducing time-of-use tariffs or other forms of demand response. Some examples include South Africa, Kenya, and Uganda (see Table 2). When it comes to residential smart metering, progress has been limited to wealthy neighborhoods in urban agglomerations. The smart meter rollout effort has also been hamstrung by early operational difficulties and malfunctioning.

When it comes to digitizing grid operations, systemic information is difficult to come by, but all countries report some degree of outage detection. Most countries also have investment plans that aim to upgrade/implement Supervisory Control and Data Acquisition (SCADA) systems. Given the high investment requirements, stepping up the grid digitalization effort will require a major expansion of private sector participation in African grids.

Table 2: Strategies for pre-paid meters and smart meters in selected African countries

Country	Pre-paid meters rollout strategy (yes/no)	Additional information	Smart meters rollout strategy (yes/no)	Additional information
Algeria	×	✗	✓	✗
Ethiopia	✓	All residential customers	✗	✗
Ghana	✓	Residential and commercial customers; all major cities	✓	NEDCo is implementing pilot projects to reduce non-technical losses
Kenya	✓	All residential customers	✓	KPLC plans to roll out of Smart Meters for all Large Power and SMEs
Morocco	✓	ONEE has a program in place to encourage the adoption of prepaid solutions (already adopted by over 300 thousand customers)	✓	Smart metering projects rolled out by ONEE and municipal distributors
Senegal	✓	Residential customers (on a voluntary basis)	✓	Pilot projects in the Dakar area
South Africa	✓	Residential customers; low-income households; geographically remote areas	✓	Smart metering projects rolled out in the City of Tshwane, Johannesburg, and the Nelson Mandela Bay Municipality
Tanzania	✓	All residential customers	✓	TANESCO is advancing in its plan to install Automatic Meter Reader (AMR) meters for Large Power Users and Medium Power Users.
Uganda	✓	All residential customers	✓	Umeme has injected approximately US$19m in the Automated Meter Reading (AMR) technology
Zambia	✓	All residential customers	✓	Target is maximum demand customers, bulk supply points and commercial postpaid customers

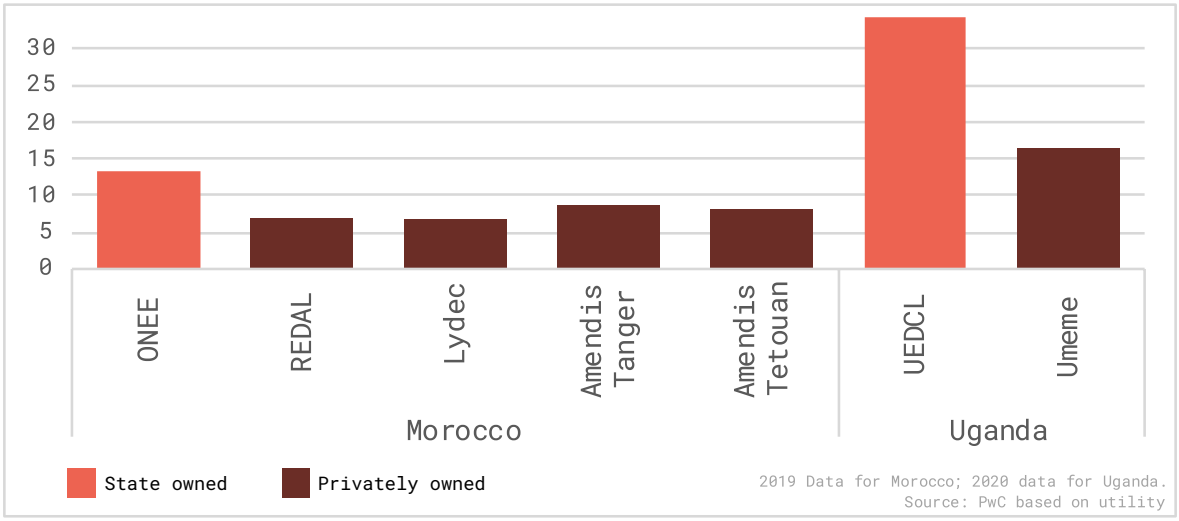
Source: PwC analysis based on company level data.

3.2 Private distributors in Africa are already outperforming public utilities

Private sector participation in African grids is currently the exception rather than the rule, but there are a few cases where PSP has been allowed. In countries that allow at least some form of private participation in their distribution segment, the few existing private operators are outperforming public utilities on technical, financial, and commercial fronts.

Starting with technical indicators, average national figures for T&D losses reported in section 2.1 obscure the notable difference in losses registered by private and public sector distributors. On distribution losses, the examples of Morocco and Uganda clearly indicate that private distributors outperform their state-owned counterparts (see Figure 14). Some of the disparities are certainly accounted for by market size and customer categories served. Yet the trend is unequivocal and is closely related to the more stringent performance KPIs that private distributors are presented with.

Figure 14: Distribution losses in selected African utilities (%)



Also on financial indicators, private operators outperform public distributors. In the example of Zambia's CEC and ZESCO, CEC appears to be in a far more financially sound situation than its public counterpart, regardless of the different customer categories and regional coverage of the two. The private company has lower net debt to equity than ZESCO (15% vs. 49%) and is operating at a profit both considering only its operations as well as its profits after-tax. On the other hand, ZESCO reports losses on both metrics. Similarly, CEC has a positive net cash flow from operating activities, while ZESCO reports a negative net cash flow, meaning that the public company is unable to generate earnings even from its day-to-day operations.

Data for Moroccan private distributors are more difficult to assess, given the opacity of financial and corporate reporting by ONEE and some municipal concessionaires. Nevertheless, also in this case the private company Lydec runs operating profits both before and after tax, while ONEE posted an after-tax loss for its 2019 financial results.

The comparison of Umeme and UEDCL in Uganda depicts a similar picture. In this case, it is worth highlighting that Umeme has a near-monopoly on Uganda's distribution segment, with the company paying a sizeable lease fee to operate UEDCL's network infrastructure. This rent allows UEDCL to report profits after-tax, as much as its private counterpart. However, analyzing the net cash flow from operating activities shows that Umeme reports positive values, whereas the public distributor operates at a loss. Umeme's superior financial performance is confirmed by the leverage ratio of the two companies – calculated as total assets/equity. UEDCL reports a ratio of 0.12, i.e., far lower than the 0.30 ratio usually considered a reasonable threshold to avoid financial distress. Conversely, Umeme's leverage ratio stood at 0.33 in 2020, indicating a lower debt load compared to its actual value.[15]

Table 3: Comparison of financial performance of public and private distributors

Country	Utility	Public/ Private	Operating profit	Profit before tax	Net cash flow from operating activities
Morocco	ONEE	Public	✓	✗	no data
	Lydec	Private	✓	✓	no data
Uganda	UEDCL	Public	✓	✓	✗
	Umeme	Private	✓	✓	✓
Zambia	ZESCO	Public	✗	✗	✗
	CEC	Private	✓	✓	✓

Data is for 2019 or the latest year available.

Private companies seem to outperform public ones also on commercial indicators, notably on bill collection rates. Many African utilities struggle with a structural inability to collect bills for vast shares of the electricity they deliver to customers. The exact drivers of this are complex and country-specific, but frequently-seen trends include utilities' inefficiency of billing and metering practices, inefficiencies at collecting bills in remote rural areas, social pressure around disconnecting power to non-paying customers, as well as a non-payment culture in some communities for services they consider basic rights that should be granted for free.[16]

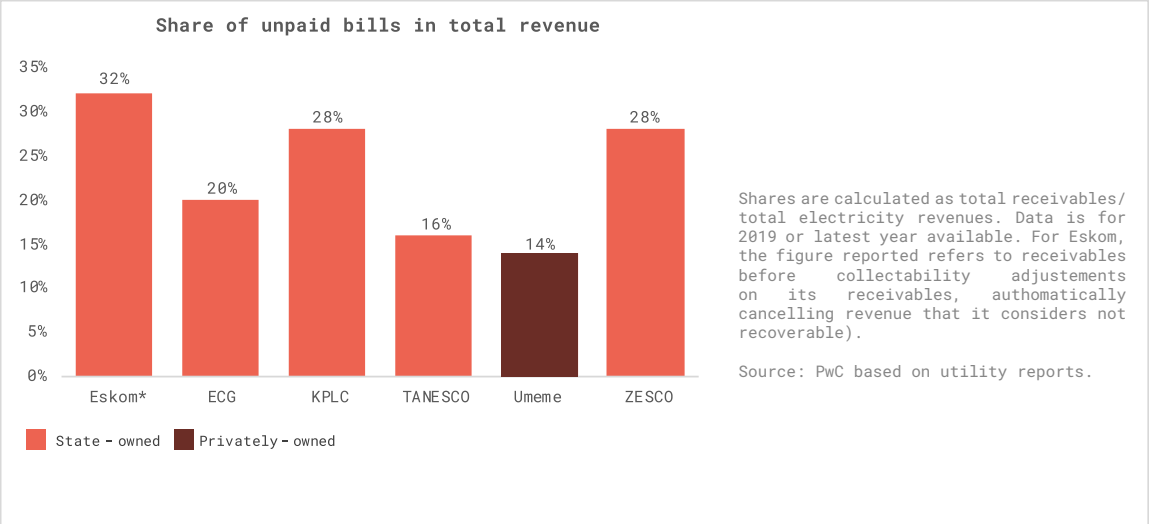
Theoretically speaking, accounting for unpaid bills is a natural part of the utility business model given that customer bills are issued and collected with a 1–3-month delay after the electricity has been

[15] Community Resource Group (2011), Small system guide: understanding utility financial statements.
[16] Masami Kojima and Chris Trimble (2016), Making Power Affordable for Africa and Viable for Its Utilities, The World Bank Group / Africa Renewable Energy Program (AFREA) / ESMAP.

delivered. Utilities report this customer debt on the asset side of their balance sheets as a trade receivable, as they expect that the money owed will end up being paid. After a set period of time of bills not being paid (typically three months), the values are written off the balance sheet and reported as a loss (also known as impaired assets).

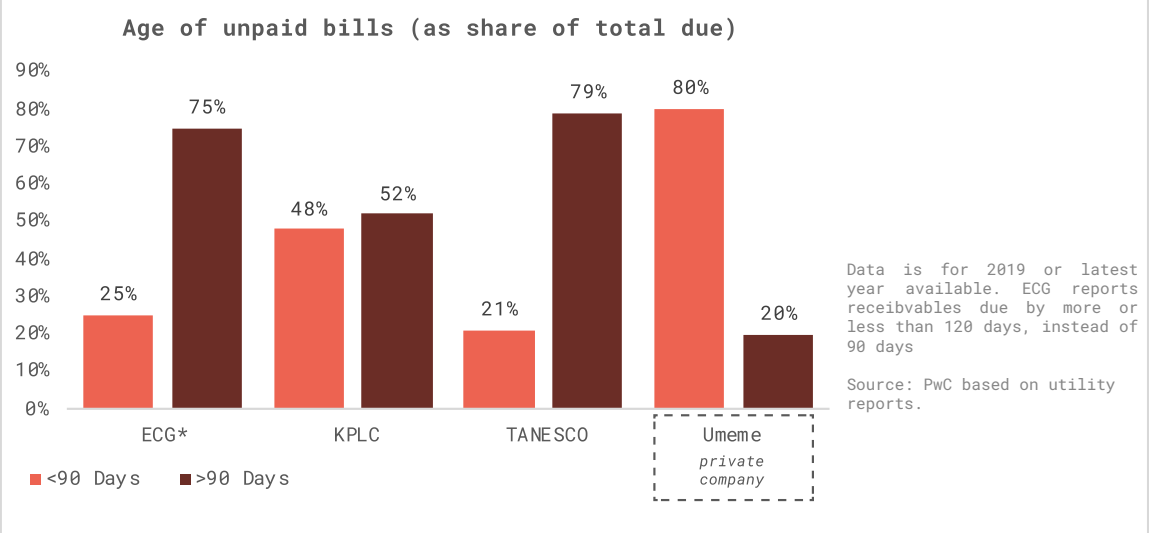
The magnitude of the bill collection issue is reported in Figure 15, which provides a snapshot of the share of unpaid bills in total revenue for companies reporting on these metrics (where a lower share is better). As in the case of other technical and financial indicators, the private distributor Umeme outperforms all the state-owned utilities for which data is available. In fact, unpaid bills account for 14% of Umeme's total revenues from electricity sales, which is a much lower share than public distributors such as Eskom, ECG, KPLC, TANESCO, or ZESCO.

Figure 15: Umeme outperforms public utilities on bill collection figures



To get an insight on the likelihood that these bills will end up getting paid, one needs to look at the age structure of the unpaid bills. Companies typically report this in terms of the share of unpaid bills that are older or newer than 90 days, where the older the bill structure, the less likely it gets that the

Figure 16: Umeme's receivables are due by less time than public utilities



utility will get paid. Also on this count, Umeme outperforms its state-owned peers. Some 80% of Umeme's unpaid bills are newer than 90 days, meaning likely to get paid, compared to a range of 20-48% for the state-owned companies analyzed.

The figures above represent only a partial picture, as they don't take account of the vast sums that get written off utility balance sheets as bed debt in any given year. The opacity and paucity of financial and accounting data for most utilities makes it impossible to run more advanced analyses or compare a larger sample of companies.

Another limitation to the analysis above is the small sample size. Uganda, Morocco, Zambia, and Ghana are rare cases in Africa where private distributors are operating in the market, and are reporting superior technical, financial, and commercial performance. Yet even in these countries it is difficult to speak of genuine market openness as private companies do not genuinely compete with incumbents. In the anomalous case of Uganda, the private distributor operates a near-monopoly. Given these limitations, we also consider it useful to draw on South America's successful experiment with private participation in grids (see Box 3).

Box 3: Successful South American examples of private involvement in grids

Colombia – Bogotá & Cundinamarca

In 1998, Bogotá's distribution networks were opened up to private involvement. CODENSA share ownership with the public utility, with mandate to operate and maintain the distribution and commercialization of electricity to more than 3.6 million customers in Bogotá and 129 other municipalities. CODENSA involvement has resulted in a number of noteworthy improvements to the quality of service and management. Since privatization, investment plans have been revamped and led to an average annual growth rate of around 4.5% over the past 23 years. Investment have been particularly focused on infrastructure expansion, evident in the continuous increases in in new connections, with a 6.7% increment in new connection points in 2021 and a 3.6% compound annual growth rate in the number of clients of the past 5 years.

Efforts made to improve the efficiency of the distribution grids and to reduce network losses are evident. Multiple substations, transformation capacity additions, the construction of 5,100 km of networks, and the installation of more than 2,500 remote control mechanisms over the course of CODENSA's tenure have made monumental improvements to the quality of service, mirrored by a 57% and 42.8% reduction in SAIDI and SAIFI respectively, over the past four years. Similarly, the implementation of a loss reduction, control, and assurance process has led to a 60% reduction in network losses since 1998 through the actuation of remote measuring and monitoring, monthly energy balance reports determining loss levels, and over 190,000 annual field inspections.

Positive outcomes of this public-private partnerships extend beyond the business framework. Significant improvements have been made to health and safety for both personnel and contractors, whilst youth training initiatives such as "Plan Semilla" provide employment opportunities and other tangible benefits to local communities.

Brazil – Goiás

The Goiás region, located in the centre of Brazil, consists of 237 municipalities with over 3 million customers in an area of 337,000 km2 with over 185,000 km of networks. Up until 2016, this region's distribution had been under the control of state and federal governments, whereupon Celg Distribuição (Celg-D), a 50.93% privately owned entity took over operation and maintenance. In 2017, 95% of Celg-D was privatised through the country's first privatization auction.

In the first two years of operation under private management, significant improvements were made to the expansion and capacity of the grid. A backlog of 23,000 connections accumulated under previous management were reduced by 6% resulting in a fivefold increase upon the previous connection rate, whilst installed capacity grid connection backlogs were reduced by 25%. Equally, the widespread integration of a remote control system for medium voltage networks led to the best ever SAIFI and SAIDI results which are currently around 50% lower than pre-privatization levels.

These developments have been supported by a tripling of the investment budget compared to pre-privatization management. As made clear by the grid improvements outlined earlier, the majority of investment was directed towards improving quality of service and grid modernisation. The resultant system efficiency has meant that the electricity tariff in Goiás remains below the average of the 54 Brazilian distributors.

4.0 Reforming Africa's Power Sectors: recent developments and current state of play

Governments tend to perceive energy security as a critical responsibility of the state; this is the reason why national energy sectors have traditionally tended to be largely state-controlled and in many cases vertically integrated, meaning that the entire chain, from production to transmission and distribution is controlled by one entity. Vertically integrated structures also used to be well suited for a traditional electricity model, where a large institutional structure with a diversified revenue base was required to finance large capital-intensive projects.

Shifting global power sector dynamics including rapid technological innovation, renewable energy deployment, decentralization, and digitalization have driven a shift toward a liberalized electricity sector model both in terms of private participation and also in terms of splitting vertically integrated utilities into separate entities, a process called unbundling. African states are no exception to this global trend: relative to a few decades ago, several countries across the continent have shifted towards more competitive market models.[17]

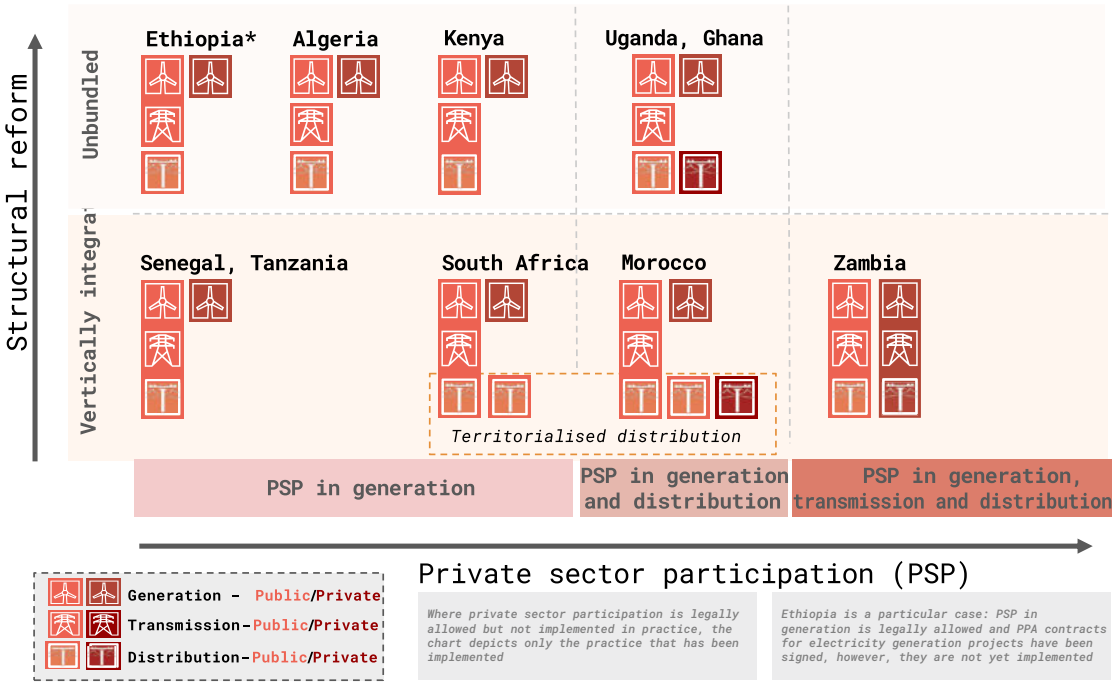
In the context where sovereigns have limited fiscal headroom to finance the energy transition, key to this ongoing transformation is the need to expand the role of the private actors in the electricity sector in order to mobilize the necessary investments. However, expanding private sector participation (PSP) in African markets can hardly be separated from a structural reform of the countries' electricity sectors, whereby the vertical unbundling of state-owned utilities helps decrease the market power of incumbent operators, thus creating new avenues for investments. To make sense of the current structure of the electricity market in the ten selected countries, we benchmarked and analyzed them in terms of three dimensions: (1) the presence and strength of a regulatory authority; (2) the structural reform of their power sectors; and (3) the degree to which private sector participation (PSP) is foreseen in various segments of the electricity value chain. These three dimensions are closely intertwined, considering that:

- any competitive power sector model requires the presence of a strong and independent regulator to ensure a level playing field and correct and fair market functioning, and curb monopoly power;
- recent attempts at reform were mostly driven by the transitioning from the legacy model of vertically integrated, state-owned utilities to various degrees of unbundling;
- to have a full picture of how countries organize their electricity sector, it is crucial to understand what role is foreseen for private actors.

Figure 17 provides a schematic overview of the electricity sector of the ten analyzed countries.

[17] Paul H. Suding et al. (2018), Transformation of the Power Sector and Its Framework in Developing Countries, GIZ.

Figure 17: Structure of the power sector in selected African countries



4.1 The role of the regulator

Transitioning from a vertically integrated model to a more competitive framework inevitably increases the complexity of the system. To deal with this complexity, protect customers from abuse of monopoly power, and ensure a level playing field where new, private entrants compete evenly with incumbents, countries need to have strong and independent regulatory authorities. Indeed, the perception of the existence of a fair and transparent regulator is often considered a prerequisite for any investor willing to enter a new market. The strength of the regulator is typically measured in terms of political and financial independence.

Analyzing the independence of the regulatory authorities in our ten focus countries, we can broadly identify two main categories:

1. Countries with a strong, independent regulator;
2. Countries with a relatively weak regulator – either for lack of transparency, insufficient financial and/or political independence, inadequate administrative capacity, etc.

Countries such as Zambia, Tanzania, Senegal, Kenya, Uganda, and Ghana can be considered as closer to the first model. The 2020 Regulatory Governance Index, developed by the African Development Bank, ranks all of them as having "substantial levels of regulatory development" for this index, on the basis of indicators such as independence, accountability, transparency and open access to information.[18] South Africa was evaluated by the same publication in 2019, obtaining a similar score.[19]

[18] AfDB (2020), Electricity Regulatory Index for Africa 2020.
[19] AfDB (2019), Electricity Regulatory Index for Africa 2019.

On the other hand, Morocco, Ethiopia, and Algeria can be seen as countries with relatively weak regulatory authorities. In the case of Ethiopia, the regulators' independence is rather low, it being solely financed by the Government and accountable to the country's Ministry of Energy. Morocco's regulator, in turn, is still in its infant stages, as the institution was legally established in 2016 but only became operational in 2020. As for Algeria, the "Commission de Régulation de l'Electricité et du Gaz" (CREG) is funded through license fees and fares collected from end-consumers, which makes it financially independent. However, the regulator's political independence remains low, given that the Government supervises how resources are managed.[20]

4.2 Structural reform of the power sector

Throughout the past decades, several African countries underwent a significant transformation of the structure of their power sectors towards a more liberalized model. Different circumstances and national priorities shaped the different attempts at reform, with many countries being driven by requirements of the World Bank's structural adjustment programs or other donor packages. The main trend has been the transitioning from the legacy model of vertically integrated, state-owned utilities to various degrees of unbundling. The highest degree of liberalization would be the corporatization and commercialization of state-owned utilities, whose core functions would be separated in the generation, transmission, and distribution segments.[21]

The ten countries under analysis offer a rather diverse picture of such reforms. Broadly speaking, three main groups can be identified: countries that continue to have vertically integrated, state-owned utilities; countries that made some progress towards unbundling; and countries that can be considered "frontrunners" and are progressing towards full unbundling.

Figure 18: Structural reform in the power sector of selected African countries

The first group encompasses Senegal, Tanzania, Zambia, South Africa, and Morocco. Each of these has a different organization of the electricity sector, but they share the important commonality of having an incumbent vertically integrated state-owned utility which is active in all three segments of the electricity sector. For all five countries, the respective national utility is the most important player in the market and holds key responsibilities for the functioning of the system, particularly with regards to transmission and distribution.

[20] Information on Morocco and Algeria retrieved from: Medreg (2020), Mediterranean Energy Regulatory Outlook 2020.
[21] Joseph Kapika and Anton Eberhard (2013), Power-Sector Reform and Regulation in Africa, HSRC Press.

This is shown by the cases of Senegal and Tanzania, where Senelec and TANESCO, respectively, are the sole operators of on-grid transmission and distribution networks. In Zambia as well, the vertically integrated public company ZESCO is responsible for most on-grid connections, with the notable exception of mining firms in the Copperbelt province which have historically been served by a private distributor (Copperbelt Energy Corporation – CEC).

Such an institutional framework, where a publicly owned company has a near monopoly on the industry and faces no competition, means risks are shifted disproportionately to consumers or taxpayers, potentially leading to poor quality of service, low efficiency gains and precarious fiscal standing of the utility itself.[22] Additionally, the lack of competition may pave the way to other negative tendencies, such as operational inefficiencies, overstaffing, as well as underspending on maintenance and expansion of assets.[23]

The last two countries from this group – South Africa and Morocco – also have vertically integrated utilities, with Eskom and ONEE emerging as the dominant players in their respective markets. However, both countries follow a territorialized approach to electricity distribution, whereby municipal distributors act alongside the state-owned utility. This territorialized organization stems from historic legacies rather than market reforms and presents a number of weaknesses. These include, primarily, the potential emergence of different levels of quality of service across the country, with some utilities operating in less densely populated areas being at a competitive disadvantage compared to utilities in urban areas. Moreover, although the presence of several operators decreases the market power of Eskom and ONEE, it does not lead to more competition, as municipal distributors still enjoy a monopoly in their respective concession areas.[24]

The second group consists of Algeria and Ethiopia, which have made some degree of effort towards full unbundling. In the case of the former, the restructuring of the state-owned company Sonelgaz led to the creation of two subsidiaries taking over the transmission and distribution segments of the Algerian market, namely the Electricity Transmission Grid Management (GRTE) and Electricity and Gas Distribution Company (SADEG). However, this reform fell short of creating three separate, independent entities, as both GRTE and SADEG remain full subsidiaries of Sonelgaz.[25] As for Ethiopia, the country promoted a partial unbundling of its national utility: when the former EEPCo was restructured in 2013, only two different entities were created – Ethiopian Electric Power (EEP), responsible for state-owned generation assets and transmission lines; and Ethiopian Electric Utility (EEU), responsible for the ownership and operation of the distribution network.[26]

Despite not being part of the same group, it is worth noting that Algeria and Morocco differ from the other countries in one important aspect, namely that electricity services of their incumbent utilities are integrated with gas and water services, respectively. This stems from the two countries' historic legacy but may be problematic as it fosters the risk of cross-subsidization between the different utility sectors.

The last group comprises three countries that can be considered frontrunners in the promotion of structural reforms of the power sector in Africa: Kenya, Ghana, and Uganda. Notwithstanding some country-specific differences, all three have promoted important reforms in their electricity sector and are effectively moving towards unbundling – i.e., a situation where power generation, transmission and distribution are operated by different actors, independent from one another.

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[22] Maria Vagliasindi and John Besant-Jones (2013), Power Market Structure – Revisiting Policy Options, International Bank for Reconstruction and Development / The World Bank.
[23] Masami Kojima and Chris Trimble (2016), Making Power Affordable for Africa and Viable for Its Utilities, The World Bank Group / Africa Renewable Energy Program (AFREA) / ESMAP.
[24] Zainab Usman, Tayeb Amegroud (2019), Lessons from Power Sector Reforms The Case of Morocco, World Bank
[25] Boulle (2019), Global Experience of Unbundling National Power Utilities.
[26] Thomson Reuters Practical Law (2020), Electricity regulation in Ethiopia: overview.

Kenya commenced reforming its power sector in 1996, when the generation segment of the incumbent Kenya Power & Lighting Company (KPLC) was split from transmission and distribution. Concurrently, the Kenya Electricity Generating Company Limited (KenGen) was created, incorporating both the generation business of KPLC as well as the activities of the former Kenya Power Company – which owned large parts of the country's hydropower generation. A second wave of reforms began in 2007, when KenGen was partially privatized through an initial public offering of 30% of its equity on the Nairobi Stock Exchange (NSE), reflecting the government's willingness to raise capital. This was followed by the public listing of KPLC, with the government's share decreasing over time to the current 51%.[27] Subsequent reforms of the electricity sector also led to the creation of a separate state-owned transmission company – Kenya Electricity Transmission Company (KETRACO) – which is tasked by the Government to expand the high and medium voltage transmission network and associated substations, and undertake electricity transmission alongside KPLC.[28]

Ghana's power sector has been liberalized since the late 1990s, following the unbundling of the incumbent utility Volta River Authority (VRA). The VRA was previously responsible for generation and transmission of electricity throughout the country, while also distributing electricity in the northern regions via its Northern Electricity Department (NED). The VRA's restructuring led to the establishment of Ghana Grid Company (GRIDCo) as the sole operator of the transmission network, while the VRA continues to operate as a power generation company. As for electricity distribution, NED was transformed into a separate subsidiary of the VRA (the Northern Electricity Distribution Company – NEDCo), whereas the largest distribution company is another public entity, namely the Electricity Company of Ghana (ECG).[29]

Last but not least is Uganda, whose power sector structure is oftentimes presented as a trailblazer in sub-Saharan Africa.[30] Reforms in the country took place in two incremental steps. First, the unbundling of the state-owned, vertically integrated Uganda Electricity Board, which led to the creation of three separate companies for generation, transmission, and distribution of electricity (i.e., UEGCL, UETCL and UEDCL). Second, the liberalization of the distribution segment, following the externalization of the vast majority of UEDCL's infrastructure to the private company Umeme, under a 20-year concession agreement. As a result of this agreement, as of 2020 Umeme controls almost 95% of Uganda's distribution segment, particularly in urban and peri-urban areas. The company is a public limited liability firm, listed on the Uganda Security Exchange (USE) and cross-listed on the NSE.[31]

The case of Uganda is quite emblematic, as it highlights how vertical unbundling is only one side of the story of power sector reforms. Indeed, unbundling is not an end itself, but rather a means to achieve better sector performance. To try and understand the full picture, one should analyze what role is foreseen for private actors in the electricity sector.

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[27] EPRA (2019), Energy and Petroleum Statistics Report.
[28] Catrina Godinho Anton Eberhard (2019), Learning from Power Sector Reform: The Case of Kenya, World Bank.
[29] Ebenezer Nyarko Kumi (2019), The Electricity Situation in Ghana: Challenges and Opportunities, CGD
[30] Catrina Godinho, Anton Eberhard (2019), Learning from Power Sector Reform: The Case of Uganda, World Bank.
[31] ERA (2019), Electricity Supply Industry Performance Report for the Year 2019.

4.3 Private sector participation in grids in Africa

Our second dimension of analysis concerns the degree to which private sector participation (PSP) in generation and grids is foreseen in the ten analyzed countries. As a matter of principle, reducing market concentration and market power of incumbents by means of PSP can be a mechanism to attract additional investments and improve overall sector performance. This, in turn, can also contribute to providing better service to customers, while decreasing the cost of service thanks to increased competition.[32]

Notably, PSP in power generation is legally allowed in all ten countries under analysis. As a result, independent power producers (IPPs) are already in operation in nine out of ten nations, with Ethiopia being the only country where no IPPs are operational yet.[33] Conversely, private operators contribute to large shares of electricity generation in several of the other markets, attaining more than 50% of total generation in Senegal, Morocco, and Uganda.

The picture changes for the transmission segment, as transmission operations are typically run by one public company per country, which has a monopolistic position in the segment. The two exceptions to this are Zambia and Kenya. Zambia is the only country among the ten analyzed where PSP in transmission is legally allowed, as evidenced by the presence of the private company CEC.[34] On the other hand, Kenya has two public companies currently responsible for electricity transmission, KPLC and KETRACO, and the country's regulatory framework allows, in principle, PSP in the segment.

The degree to which African countries allow PSP in the distribution segment tends closer to the monopolistic framework reserved for power transmission, rather than the liberalization approach adopted in power generation.

Three main groups of countries can be identified: countries where PSP is not allowed; countries where PSP is legally allowed but de facto not implemented; and countries where some form of PSP is implemented.

Figure 19: PSP in the distribution segment in selected African countries

[32] Katharina Gassner, Alexander Popov, Nataliya Pushak (2009), Does Private Sector Participation Improve Performance in Electricity and Water Distribution?, PPIAF / The World Bank.
[33] Two geothermal projects are currently under construction by the IPPs Corbetti and Tulu Moye. For additional information, see: International Trade Administration (2020), Ethiopia - Country Commercial Guide.
[34] It is worth noting that CEC's presence in Zambia stems primarily from historic circumstances, rather than recent attempts at reforming Zambia's power sector. The company has been in operation since 1953 and was incorporated into the state-owned mining conglomerate "Zambia Consolidated Copper Mines" (ZCCM) in 1982. Its privatization took place in 1997, following the privatization of ZCCM. For additional information, see: CEC (2021), Copperbelt Energy Corporation Plc: Birth and Evolution

The first group treats on-grid power distribution as a natural monopoly, entrusting the incumbent public utility with the responsibility of sole operator of the segment. This is the case of Algeria, Ethiopia, and Senegal. Interestingly, the first two countries made some progress towards vertical unbundling but opted not to open electricity distribution to private operators.

The second group of countries is similar to the first one insomuch as there are currently no private distributors in operation. However, the possibility for private companies to obtain a distribution license is legally foreseen, even if this has not yet been implemented.[35] Countries with this legal framework are South Africa, Tanzania, and Kenya. As compared to the first group, such an approach demonstrates a different attitude towards the possibility of PSP in distribution. In the case of South Africa, private companies are already involved in different forms of electricity retail services, whereas in Tanzania two small private distributors have been granted a license to serve communities close to their respective hydropower facilities.[36] The difficulty of implementing the legal possibility of PSP is often related to unclear regulation and the difficulty of competing on price with the incumbents. This is notably the case in South Africa, where the business case for private distributors is eroded by the non-cost-reflective tariffs and the fact that distributors need to compete with Eskom on retail price as well as on purchase price for the electricity generated.

The third group includes four countries where some form of PSP in distribution has been implemented: Ghana, Zambia, Morocco, and Uganda. In Ghana, the privately-owned Enclave power company Ltd (EPC) has been in operation since 2015. While the company's contribution to the market in terms of customer base and electricity sales is still minor compared to the two public distributors ECG and NEDCo, EPC is outperforming both public firms on distribution losses: 2,12% in 2020, compared to 26,6% of ECG and 27,2% of NECDo.[37]

Zambia's on-grid power distribution is managed by three main players: the vertically integrated state-owned utility ZESCO, and the private operators North Western Energy Corporation (NWEC) and Copperbelt Energy Corporation (CEC). The former has a minor role in the market, being responsible for power distribution to some households in the North-Western province. On the other hand, CEC is a key player in Zambia's electricity sector, as it is responsible for power distribution to mining entities in the Copperbelt province, which consume over half of the country's total electricity generation.[38]

[35] Including cases where the contribution of private distributors is yet to attain significant levels.
[36] For additional information on Tanzania's distribution subsector, see: EWURA (2019), Electricity Performance Report 2018/19.
[37] Ghana Energy Commission (2021), National Energy Statistics 2000-2020.
[38] The mining sector has strategic significance for Zambia's economy, with copper accounting for over 75% of exports. For additional information, see: ERB (2019), Energy Sector Report 2019.

Morocco's territorialized approach to the distribution segment sees the public utility ONEE operating alongside municipal distributors. Indeed, distribution from ONEE is considered the default option, but municipalities are allowed not to use ONEE's services and instead opt for: (a) directly managing power distribution through the creation of a municipal electricity distribution service (régies); or (b) delegating the management of the service to a private concessionaire (gestion déléguée), via long-term concession contracts (30-years). As a result of this framework, the distribution of electricity in the main cities of Rabat, Tangier, and Tetouan and Casablanca is performed by private concessionaires Lydec, Redal, and Amendis, respectively.[39]

Finally, as mentioned in the previous section, Uganda adopted a highly liberalized approach to electricity sector reform. This is particularly evident in the distribution segment, where the private company Umeme controls almost 95% of the country's power distribution as of 2020. This stems from Uganda's broader policy to attract private investments in the electricity market, which led the public utility UEDCL to sign a 20-years concession agreement with Umeme in 2005. Through this agreement, Umeme was made responsible for the vast majority of the country's distribution infrastructure.[40]

Table 4: Typical length of distribution concessions

Country	Power distributor(s)	Typical length of concession
Algeria	SADEG	Information not available
Ethiopia	EEU	Max. 20 years
Ghana	ECG	Max. 20 years
	NEDCo	
	EPC*	
Kenya	KPLC	50 years
Morocco	ONEE	Information not available
	Public municipal distributors	Information not available
	Private municipal concessionaires*	30 years
Senegal	Senelec	25 years
South Africa	Eskom	15 years
	Public municipal distributors	
Tanzania	TANESCO	20 years
Uganda	Umeme*	20 years
	UEDCL	Information not available
	Private distributors*	Information not available
Zambia	ZESCO	15 years
	CEC*	
	NWEC	

**private distributors*

[39] Zainab Usman, Tayeb Amegroud (2019), Lessons from Power Sector Reforms The Case of Morocco, World Bank Group.
[40] ERA (2019), Electricity Supply Industry Performance Report For The Year 2019.

5.0 Looking into the theory: private sector participation models for grids

The private sector can contribute to overcoming the challenges present in African countries' electricity sectors by injecting financial resources and technical know-how under various contractual arrangements. As highlighted in the previous chapter, market reforms and unbundling are instrumental in enabling and attracting private participation in electricity networks, but they are not a prerequisite for all forms of private involvement. Private participation in infrastructure represents a complex spectrum ranging from service contracts to divestiture, exhibiting varying degrees of delegated control and ownership.

Perhaps the most important distinction between private participation models is related to how risk is shared between the public and private sectors. On the service contracts end of the spectrum, the public sector retains all the risk, with the private entity simply acting as a supplier of a good or service. Similarly, divestiture and merchant projects do not involve any formalized public-private risk-sharing relationship, but in this case, the private sector assumes all the risks.[41] Between these two extremes, risks are shared between the two sectors, under what are generally considered public-private partnerships (PPPs). Under management contracts, the private sector is only responsible for the operation and maintenance of the asset, with the public sector shouldering the commercial risks and capital investment. With leases and concessions, the burden of commercial risks and capital investments, respectively, are shifted to the private operator.

Private sector participation can be designed to be time-bound or indefinite.[42] In the case of time-bound models, such as service and management contracts, leases, and concessions, the responsibilities taken on by the private entity revert to the public sector at end of the agreement. Divestiture, on the other hand, awards private entities the right to own shares in or the entirety of a transmission or distribution company indefinitely.

Private sector participation models are also differentiated based on whether the assets to be managed are preexisting on not. Brownfield solutions entail a private sector entity assuming some or all of the functions of an existing state-owned utility responsible for transmission and/or distribution assets. Conversely, greenfield solutions involve the construction of new assets to be owned and managed by a private entity. Service and management contracts and leases represent exclusively brownfield private participation models, while concessions and divestiture include both types.

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[41] UNECA (2011), Public-private partnerships in Africa's energy sector: challenges best practices and emerging trends

[42] Divyam Nagpal & Ignacio Perez-Arriaga (n. d.). How is the distribution sector in low-access countries attracting private sector participation and capital?

In contrast to electricity generation where the prevalent independent power producer model is a greenfield solution, private involvement in electricity grids in Africa has so far been dominated by management contracts and brownfield concessions.[43] These have typically been applied to vertically integrated state-owned utilities, but notable examples of distribution-only concessions also exist (these usually include retail as well, as in the absence of liberalization, most African distributors are also, by default, retailers). Private participation in transmission has been a rarity, with examples limited to a handful of whole-of-grid concessions as part of a vertically integrated utility concessions.[44]

The remainder of this chapter reviews the various types of private sector participation models applicable to transmission and distribution. Where possible, examples of African experiences with these models will be discussed, as well as references to some international examples.

5.1 Service contracts

Service contracts represent one of the simplest and lightest forms of private sector participation and are widely employed both within and beyond the electricity sector. For the duration of a service contract (between one to three years), the awarding authority pays a private operator a fixed fee to provide a service – in the power sector, for instance, this could be meter reading or billing.[45] Under such arrangements, ownership, capital investment responsibility, and operational risk are retained by the awarding entity.

5.2 Management contracts

Management contracts follow a similar logic but entail a higher level of private involvement. They generally last for a period of between two to five years and consist of a private entity managing some or all functions of a government-owned utility, albeit without owning assets in that company or taking on full commercial risks for tariff collections and asset condition. In most cases, these contracts tend to be task-specific and input-focused, and the private operator performing the task is usually remunerated with a fixed fee. In the case of more complex management contracts, such as operation and maintenance contracts, a performance-based remuneration mechanism may also be included alongside the fixed fee.

Management contracts are frequently used in cases where the condition of the asset to be managed is uncertain and the private sector would be unwilling to accept more extensive risk. As a result, such contracts, have frequently been used as transitional arrangements for improving the technical or financial performance of utilities to enable subsequent introduction of the private sector into managing infrastructure.[46] However, they can also be a means to improve utility performance for continued operation under public ownership.[47] Indeed, longer term operation and maintenance agreements have become more common where extensive private participation in the energy sector through a lease or concession agreement is deemed too politically sensitive.

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[43] World Bank (2021) Private Participation in Infrastructure Database
[44] Power Africa, CLDP, and ALSF (2021) Understanding Power Transmission Financing
[45] ESMAP (2015). Private Sector Participation in Electricity Transmission and Distribution
[46] World Bank (n. d.) Public Private Partnership Legal Resource Centre, Management/Operation and Maintenance Contracts
[47] Economic Consulting Associates (2015), Evidence and Gaps in Evidence in use of Management Contracts for Electricity Distribution & Supply

Management contracts are one of the most common forms of private sector participation recorded in the electricity sector in Africa, with 17 contracts across 15 countries.[48] The use of traditional management contracts in Africa has been complex, and their perceived success, variable.[49] Independent analyses have shown that the contracts often resulted in efficiency gains and better financial performance, but improvements were generally not sustained.[50] This is partly attributable to the short timeframes associated with these contracts, considering that 4 out of 17 were cancelled prematurely, and the majority of the remainder were not renewed following their scheduled termination dates, resulting in an average contract duration of less than four years.[51] Most of the management contracts, signed in the 1990s and early 2000s, were undertaken with initial funding from multilateral development institutions pursuing wider reforms, and many African governments entered into the contracts to secure donor finance but terminated the arrangements as soon as they became financially liable for contract fees.

The paucity of data resulting from the absence of adequate monitoring and evaluation of management contract implementation in Africa makes drawing conclusions about the performance of management contracts on the continent difficult. Existing research has highlighted that the success of management contracts depends not only on contract design and contractor performance, but also wider sector conditions generally outside the control of the contractor (e.g., market reforms).[52] Additionally, clarity about what management contracts can and cannot achieve, particularly given their short time horizons, is essential. While they may improve operational and financial performance, and therefore investment conditions, they cannot themselves raise investment finance, or address deficiencies in the broader institutional framework.[53]

Since the 2010s, hybrid contractual arrangements have emerged, which aim to address some of the shortcomings of the traditional management contract model previously applied in Africa in order to better meet stakeholder expectations.[54] This new approach shifts away from portraying more substantial private sector participation as a necessary consequence of management contracts, and emphasises strong government ownership of utility action plans and the importance of local staff assuming a share of the management responsibilities. Such contracts have been signed in Sierra Leone and Liberia and are planned for use in several other countries.

5.3 Lease agreements

Lease agreements, similarly to management contracts, entail a private entity operating the utility while the awarding authority remains responsible for financing investment into the assets. However, leases cover a longer time period (8-15 years) and involve the private operator taking on more risk, specifically the risk of tariff collection. As such, the private operator does not receive a fixed fee for its services but must use tariff collection to cover its remuneration as well as the lease fee paid to the awarding authority.[55] To date, the World Bank Private Participation in Infrastructure database recognizes only three lease agreements on the African continent, one in Ghana and two in Namibia, of which only one in Namibia is still in force. Considering this exceptionally limited track record, the performance of such arrangements in Africa is not well documented.

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[48] World Bank (2021) Private Participation in Infrastructure Database
[49] Anton Eberhard et al. (2011), Africa's Power Infrastructure: Investment, Integration, Efficiency
[50] Vivien Foster & Cecilia Briceño-Garmendia (2010), Africa's Infrastructure: A Time for Transformation
[51] Calculation based on World Bank Private Participation in Infrastructure data
[52] Rebecca Ghanada & Anton Eberhard (2007), Electricity Utility Management Contracts in Africa : Lessons and Experience from the TANESCO-NETGroup Solutions Management Contract in Tanzania, 2002-2006
[53] Vivien Foster & Cecilia Briceño-Garmendia (2010), Africa's Infrastructure: A Time for Transformation
[54] James Leigland (2020), Public-Private Partnerships in Sub-Saharan Africa: The Evidence-Based Critique
[55] World Bank (n. d.) Public Private Partnership Legal Resource Centre, Leases and Affermage Contracts

5.4 Concessions

Concessions are long-term (typically 20 to 30-year) public-private partnerships divided into two broad categories: brownfield concessions, which involve a private entity taking responsibility for the management of existing state-owned infrastructure; and greenfield concessions, under which a private entity builds and operates a new asset. A defining shared characteristic of concessions is that the majority of capital investment in building new or extending or rehabilitating existing assets is borne by the private entity, thus shifting financial risk away from the public sector. Beyond these shared elements, concessions can vary greatly in terms of size, scope, and duration.

Due to its monopolistic nature, transmission typically lends itself to whole-of-grid concessions, although greenfield projects for individual lines or packages of lines (the independent power transmission model – see Box 4) have gained traction in some developing countries. Distribution, on the other hand can more easily be divided into discrete geographical areas to be awarded as separate concessions. Performance targets are often included in concession agreements to ensure that the government's main aims are met. In the case of grid concessions, targets tend to be focused on reducing costs and upgrading and extending the network to improve reliability and increase access to electricity supply.

The African continent has witnessed few concessions for transmission or distribution. The majority of these were awarded in the 1990s and early 2000s and were in fact larger concessions for an entire vertically integrated utility – this was the case in Cameroon, Côte d'Ivoire, and Gabon.[56] While distribution-only concessions have occurred in a handful of African countries, a whole-of-grid transmission-only is yet to be seen. Concerns over sovereignty of politically delicate infrastructure has hampered private involvement in grids, even in unbundled sectors, despite the capital-intensive nature of transmission projects and urgent need for transmission capacity expansions. There is scope of private sector participation in transmission if a suitable model is adopted, and research has suggested that the Independent Power Transmission model may be well-suited to the African context (see Box 4).

[56] International Bank for Reconstruction and Development / The World Bank (2017) Rural Electrification concessions in Africa: What Does Experience Tell us?

Box 4: Independent Power Transmission Model [57]

Independent Power Transmission (IPT) models award concession-style contracts for rights a single or small number of transmission lines. As with IPP contracts successfully adopted in a number of African states, IPTs occur under BOO, BOOT, BTO and EPC contracts with a long-term Transmission Service Agreement (TSA) similar to a PPA. IPTs are awarded through tenders whereby the concession is awarded to the bidder offering the lowest cost-of-usage charge. Bidders must guarantee universal access to the transmission line, ensuring the reliability and availability of service.

Competition in the procurement of IPT concessions significantly reduces the operation and maintenance costs of the asset. As these costs are locked into the TSA, the tariff paid by the government remains stable over the contract term, which ranges from 20 to 45 years. Transmission lines procured under an IPT model are able to operate alongside a publicly-owned grid without impacting its operation and maintenance, rendering IPTs a lower-cost method for the expansion of the transmission grid. Acting as a separate and independent venture, similarly to IPPs, IPTs exploit new sources of funding thus far unavailable due to widespread restrictions on private involvement in the transmission grid – Peru, for example, raised $1.8 billion from 18 IPT tenders since first introducing them in 1998.

The success of the model in South American countries with similar per capita income levels at the time of the introduction of IPTs to African nations today is testament to the potential of this model for the development of African grids. Further to Peru, Brazil and Chile have both successfully incorporated this model into their grid development plans. The former adopted IPTs in 1999, awarding 211 concessions adding 70,000 km of lines, while the latter has held seven tenders since 2006, awarding ten projects for a total of 1.2km of lines.

Two countries in particular stand out for their use of distribution-only concessions. In Morocco, municipalities have the option to forgo distribution services provided by the vertically integrated state-owned utility ONEE in favor of private distribution companies under a 25 to 30-year concession. The greater concentration of consumers and higher profitability draw private operators to cities leaving ONEE to distribute electricity in rural areas. At the time of writing, private distributors are present in four major Moroccan cities (Rabat, Casablanca, Tangier and Tetouan).

Ugandan utility Umeme is one of the largest African private distribution companies, supplying 97% of electricity in the country.[58] In 2001, Umeme was awarded a 20-year distribution concession within a newly unbundled system with the aim of reducing losses and increasing connections. Umeme's incumbency is characterized by its good financial standing and proven track record of high-quality, efficient service provision. These credentials have allowed Umeme to continue to source the funding necessary for the upgrade and maintenance of Uganda's distribution networks, including an IPO in which 40% of its shares were floated on the Ugandan Securities Exchange. To date, Umeme has successfully achieved its performance targets, and has contributed to the creation of a financially viable power sector in Uganda, a feat achieved by only one other sub-Saharan nation.[59]

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[57] World Bank and PPIAF (2017), Linking Up: Public-Private Partnerships in Power Transmission in Africa
[58] Umeme (2020) Annual Report 2020 : Electricity Distribution for a Better Uganda
[59] Chris Trimble et al. (2016), Financial Viability of Electricity Sectors in Sub-Saharan Africa: Quasi-Fiscal Deficits and Hidden Costs

Within successful concessions, performance indicators have proven to improve over time – for instance, Umeme has considerably reduced losses and increased bill collection, and concessions in Gabon and Cameroon have led to increased connections). However, even in the absence of such targets, the commercial approach taken by the private sector has led to improvements in a number of indicators. Indeed, CIE in Côte d'Ivoire did not have any specific performance targets, but electricity supply and connection rates have remained steady, ensuring that the concession has been renewed for a second term.

A number of concessions have been entered into or announced without reaching an agreement or being terminated shortly after awarding.[60] Although the reasoning behind these failed concessions is not always clear, several seem to have ended over the issue of tariffs. In many African countries, tariffs are kept artificially low and do not cover operational costs. Attempts to raise tariffs are often met with harsh criticism and in the cases of Mali, Senegal, and Cape Verde, concessions were terminated early over such disagreements. Even within the successful examples, there has been some discussion over this topic: Cameroon's relatively high tariffs were focal issues when ENEO's concession faced renegotiations 3 times.

5.5 Divestiture

As the most absolute form of private sector participation in the electricity sector, divestiture is one of the least seen models on the African continent. A step beyond concessions, the divestiture of a utility foresees the indefinite transfer of all assets or a minority or majority stake in the company to the private sector, through direct sale, auction, or floatation on the stock market. Due to the strategic nature of electricity grids, full divestiture, which requires the public sector to relinquish all claims to the infrastructure assets has proven unpalatable to many African governments and consumers.[61] In fact, full divestiture has rarely been seen in African electricity sectors, with the exception of some small scale and off-grid distributors, and the vertically integrated Copperbelt Electricity Corporation in Zambia, which uses its transmission and distribution networks to supply power to mines.

However, some African governments, notably Kenya and Nigeria, have opted for partial divestiture, which enables an ongoing public-private relationship in the management of facility without some of the risks associated with brownfield concession contracts.[62] Kenya successfully raised significant capital by floating shares of Kenya Power and Lighting Company and KenGen on the Nairobi stock exchange, maintaining a 51% and 70% government stake, respectively.[63] In Nigeria, controlling stakes in all 11 distribution companies were awarded to private bidders based on price proposals for improvements to be made over the subsequent 5-year period. The sales raised US$ 2.5 billion for the Nigerian government [64]; however, performance outcomes have not been as expected.[65] Partial divestiture can also coexist with other forms of PSP, as evidenced by Cameroon, where AES Corporation acquired 56% of the vertically integrated SONEL and entered into a 20-year concession for the generation, transmission, and distribution of electricity.[66] A step further in divestiture can occur in a fully liberalized market through the application of merchant lines (see Box 5).

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[60] Kearney (n. d.), A private path to power in Africa
[61] International Bank for Reconstruction and Development / The World Bank (2020) Rethinking Power Sector Reform in the Developing World
[62] UNECA (2011), Public-private partnerships in Africa's energy sector: challenges best practices and emerging trends
[63] Catrina Godinho & Anton Eberhard (2019), Learning from Power Sector Reform: The Case of Kenya, World Bank.
[64] Eric Ogunleye (2016), Political economy of Nigerian power sector reform, WIDER Working Paper 2016/9.
[65] Samuel Sunday Idowu et al. (2019): Privatization of Power Sector in Nigeria: An Evaluation of Ibadan and Ikeja Electricity Distribution Companies Performance (2005– 2018), International Journal of Public Administration
[66] Kearney (n. d.), A private path to power in Africa

Box 5: Merchant lines

Merchant lines are a greenfield form of divestiture in liberalized electricity markets whereby a private entity builds, owns, and operates a transmission line at its own initiative, not the government's. The ownership term is that of the life of the asset as there is no direct government involvement in the project, aside from regulation pertaining to grid use. By targeting gaps in transmission coverage, merchant lines generate revenue from access fees and arbitrage exploiting regional and international differences in electricity prices.

The model's potential for use in African countries is limited, as regulation generally precludes competition in the transmission segment and electricity prices tend not to be geographically differentiated, therefore reducing the scope for arbitrage gains. International variations in the wholesale price of electricity are a valuable market for merchant lines but public utilities typically have a monopoly on the import and export of electricity, so merchant interconnections could only be considered for the development of interconnections if the market is liberalised.[67]

5.6 Regulation for private sector participation in grids

A robust policy and regulatory framework is crucial for encouraging private sector participation in Africa, particularly in transmission and distribution. While investors and financiers perceive power generation, off-grid electrification, and mini-grids as ready for private solutions, they see lower readiness in the transmission and distribution segments in sub-Saharan Africa.[68] Prohibitive or inadequate regulation is a key element of this perception, as private investors assign the greatest importance to policy and regulatory risks when making investment decisions.

In this context, regulation can represent a barrier to attracting private resources for electricity network development in Africa. The African Development Bank's Electricity Regulatory Index for Africa 2020 shows that on average, African electricity regulatory frameworks are at a low level of development. Although some elements of a supportive regulatory framework do exist in many countries, considerable room for improvement remains, particularly with regards to regulators' capacity to implement their own regulatory frameworks or enforce their own regulations.[69] Additionally, our review of ten African countries' power sectors has shown that regulation often prohibits extensive private participation, maintaining the operation of electricity grids as a public monopoly.

A supportive regulatory framework and an independent regulatory authority are prerequisites for creating fair competition and engaging the private sector. Where wider participation is allowed, the stability of the regulatory context is also very important, particularly when it comes to long-term participation models such as leases and concessions, which are capital intensive.

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[67] Alessandro Rubino & Michael Cuomo (2015) A Regulatory Assessment of the Electricity Merchant Transmission Investment in the EU. Energy Policy, vol. 8, 464-474
[68] Benedict Probst et al. (2020). Attracting Private Solutions and Participation in the Power Sector in Sub-Saharan Africa: Findings from a Survey of Investors and Financiers, World Bank
[69] AfDB (2020), Electricity Regulatory Index for Africa 2020

Where the remuneration of the private entity becomes contingent on bill collection, financial viability is indispensable. While private utilities can directly tackle cost drivers such as high losses and low bill collection, it is up to African governments to provide for adequate remuneration through tariff regulation. To achieve financial viability, tariffs must cover the costs associated with benchmark performance, as well as allow a reasonable return on investment. From the perspective of the government and the end users, the remuneration mechanism must also incentivize private operators to work towards wider energy sector goals such as expanding energy access and/or improving service reliability.

Regulation for the remuneration of private operators tends to fall into two broad categories: cost-based regulation and incentive-based regulation. Cost-based (or rate-of-return) regulation passes on the total costs of providing the service to customers and has been traditionally applied to state-owned utilities. This model does not provide incentives for cost reductions or efficiency gains, and the resulting high costs may make subsidies for low-income consumers necessary. In contrast, incentive-based regulation, which is more widely used today, introduces incentives and penalties to encourage performance improvements. Of the subtypes of incentive-based regulation, the price cap is generally used where the expansion and development of the network is essential, while the revenue cap is usually applied where energy demand is constant, and the main goals are higher efficiency and lower costs. However, neither cost-based nor incentive-based regulation guarantee both grid development and cost reduction. As such, they tend to be deployed in conjunction with performance-based premiums or penalties (e.g., SAIFI/SAIDI reductions, loss reduction, additional connections).

Regular tariff reviews are needed, as well as reviews of the basis of the remuneration mechanism itself, to account for the evolution of the power system and associated costs and external factors such as macroeconomic fluctuations. As a general guideline, tariffs should be updated yearly, or even monthly, and the remuneration model, every three to six years, to allow for a re-evaluation of operators' recognized costs and enable the passing of efficiency gains to consumers.

Conclusion

The structural challenges facing Africa's power sectors are persistent: access to electricity remains limited, and where access exists, electricity consumption and service reliability tend to be low. Addressing these long-standing problems requires large investments in grid infrastructure, which has traditionally been the responsibility of vertically integrated state-owned utilities. However, in most African nations these utilities are in a dire financial situation, giving rise to a negative spiral involving chronic underinvestment in grids, poor service quality, a shrinking consumer base, and the need for financial injections from governments to avoid collapse.

However, this vicious cycle can be overcome through a combination of regulatory reforms and private sector participation (PSP) in the power sector. PSP offers African governments the opportunity to enlist private sector financing, technology, and expertise to expand access and improve the quality of service. Private involvement in grid infrastructure represents a wide spectrum of arrangements, from service contracts to public-private partnerships to divestiture. These models can be time-bound (ranging from as little as two years for a service contract to over thirty years for a concession) or indefinite and entail various divisions of risks and responsibilities between the public and private sectors. Although not a prerequisite for any and all PSP, the absence of unbundling and liberalization greatly limit the scope and potential benefits of private participation in a country. The vertical unbundling of state-owned enterprises can decrease the market power of incumbent utilities, creating new, more attractive opportunities for private involvement.

To date, private participation in African grid infrastructure has shown a limited track record, with examples concentrated in brownfield solutions such as management contracts and concessions, generally for entire vertically integrated utilities rather than in individual unbundled market segments. Crucial lessons learned can be derived from these past examples of private participation, but there is considerable room for innovation in this area, with some forms of PSP, for instance the Independent Power Transmission model popular in other developing countries, yet to be tested on the continent.

Finally, PSP is most effective when implemented within a supportive regulatory environment. Although not a prerequisite for all private participation, unbundling and liberalization are indispensable for unlocking the full benefits of private involvement. To attract more extensive private participation, regulation must also guarantee the financial viability of utility business models by providing for adequate remuneration of benchmark costs and reasonable returns on investment. Finally, an enabling regulatory environment and a supportive, ambitious, and committed government are indispensable to the success of any form of private involvement.

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