POWER SECTOR REPORT

NIGERIAN POWER SECTOR REVIEW

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SDN supports the efforts of those affected by the extractives industry and weak governance. We work with governments, companies, communities and other stakeholders to ensure the promotion and protection of human rights. Our work currently focuses on the Niger Delta.

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Executive Summary

Nigeria's power sector is failing. After $2 billion was spent on the nationalised National Electric Power Authority (NEPA) in the 1980s and 1990s, the Authority had an all-time low 1,700 MW of power capacity. This was hopelessly inadequate to meet the growing needs of the country. It was also clear that the Government could not afford the necessary investment in generating capacity, then estimated at $40 billion in capital costs. It needed to privatise in order to produce this investment.

In 1998, a new approach was tried, with the creation of a number of Independent Power Producers (IPPs) and the purchase of power from the International Oil Companies (IOCs). Yet this attempt at a partial privatisation of the generation sector did not significantly increase the availability of power. Thus the Government decided on complete reform. It enacted the Electric Power Sector Reform Act (EPSR) of 2005, which created an independent regulator in the Nigerian Electricity Regulatory Commission (NERC). This brought in the necessary reforms to create a system of private generators and distribution companies by 2013.

Yet five years down the road, the sector is still struggling to secure enough investment, and is riddled with debt.

Investment still remains far below the 20 GW of capacity demanded by the "Vision 2020" Policy. So why has privatisation so far failed to produce the hoped-for improvements? The reasons are many and various.

1. The 11 distribution companies (discos) are not in alignment with the nine transmissions zones.

2. Metering is inadequate, creating under-billing, bypassing of tariffs and stealing.

3. There is a low level of power output and it is deteriorating.

4. Most of the new generating capacity is unfinished.

5. There is no enumeration of customers or basic market information to guide both tariff setting and expectations.

6. The wide variety of tariffs bears little relation to costs.

7. The expansion of the transmission system has been inadequately planned and slow.

8. There is a major lack of investment capital.

9. There is a chronic lack of gas available for fuel with an inadequate gas supply infrastructure.

10. The plans failed to allow for 'systemic risks'.

11. There is a lack of 'back-to-back' contracts, particularly affecting gas purchasing, but also for forcing the discos to take volumes of power.

12. The system of tariff formulation through Multi-Year Tariff Order (MYTO) is inflexible.

13. There is considerable tension between the generators (gencos) and the discos, each blaming the other.

14. The risks relating to foreign exchange and the potential of demand have been under-assessed.

15. Expectations of demand have been over-estimated.

16. There has been a chronic lack of investment in the sector as a whole.

17. There is no effective legal regulation regarding theft of electricity.

18. Most of the discos are effectively bankrupt.

The net result of all this is that the sector needs considerably more political attention than it has recently received. This report looks in detail at these problems and how they can be solved.

Contents

Privatisation

Searching for a model for privatisation

Further to Nigeria's Vision 2020 plans, its power sector needed private investment and searched for a suitable model for privatisation to achieve the goals of Vision 2020. The model demanded:

1. That the existing Power Holding Company of Nigeria (PHCN) be unbundled, leading to the separation of generation, transmission and distribution. This would require separate companies with variation in ownership and retail capacity.

2. That a competitive electricity market be created, initially with a single buyer – the Nigerian Bulk Electricity Trader – but with a growing number of suppliers.

3. That transmission had to remain a monopoly for security reasons, but could be split up at a later date.

4. That an independent regulator was required, which would ensure that prices would be fair, but reflect proper costs to give investors a reasonable return.

But there were further problems to take into account, which could make the initial process of privatisation fail:

1. The privatised successors to the Power Holding Company of Nigeria (PHCN) were burdened with its debts. While the Nigerian Electricity Liability Management Company (NELMC) was set up to deal with this issue, the level of available tariffs was inadequate to create clean balance sheets for the successors of PHCN and thus allow them to borrow.

2. In addition, PHCN had an excessively large workforce, so privatisation had an effect on employment in the sector, which had to be handled by the Federal Government.

3. The capital incentives for the new IPPs were inadequate. Tax holidays were only offered in economically disadvantaged areas of the country, while foreign exchange requirements proved problematic for the Central Bank of Nigeria.

This initial attempt at privatisation thus created a bad start.

The pre-privatisation situation

Organised power production in Nigeria started in the 1950s, with the Electricity Corporation of Nigeria in Lagos. The Nigeria Dams Authority also provided electricity from hydropower and merged with this corporation in 1972, giving birth to the National Electricity Power Authority (NEPA).

Although NEPA served its purpose for a time, it also increasingly failed to deliver sufficient power for a growing economy and was mired in allegations of corruption. There was a need for government to find a way to quickly finance new investment, or the country would lose billions as a result of self-generation. The success of privatisation in South America pointed the way.

The search for a policy of privatisation in the power sector started in 2001 and produced the Electric Power Sector Reform Act (EPSRA) in 2005. This led to the corporatization of NEPA, which produced the Power Holding Company of Nigeria (PHCN), with 17 companies. There were 11 distribution companies (discos), six generating companies (gencos) and a transmission company. An independent regulator was established to draw up a roadmap to full privatisation. The PHCN was vertically integrated, but started trading between the companies to evaluate how the new system would work.

The relationship between transmission, the discos and the gencos

The splitting up of a vertically integrated power utility involves three factors for consideration. There are social questions, commercial questions and technical questions. In relation to the social issues, the division of power distribution has to consider the number of households, the type of demand, whether urban or rural and how the customers respond to the new system.

The commercial viability of the new entity is also vital. It needs to be self-sustainable. This requires a design that is sufficiently varied that the customer mix does not encourage heavy cross-subsidy amongst the tariff classes and does not skew the service towards urban profitability at the expense of the rest of the area.

The technical challenge is considerable. There is a need to ensure that the transmission network is in tune with the distribution networks. The discos need to be mapped out to ensure that there are adequate transmission substations connected with them. The discos need to have a good knowledge of the power flows and be clear as to how to avoid stranded power generated by the gencos. The distribution systems need to have detailed knowledge of the ebbs and flows of demand to be able to get increases in power quickly from the gencos.

However in the case of Nigeria, it is not very clear what political, policy or commercial decisions led to the splitting of the system into 11 discos along state lines (see figure 1). This has created a host of problems.

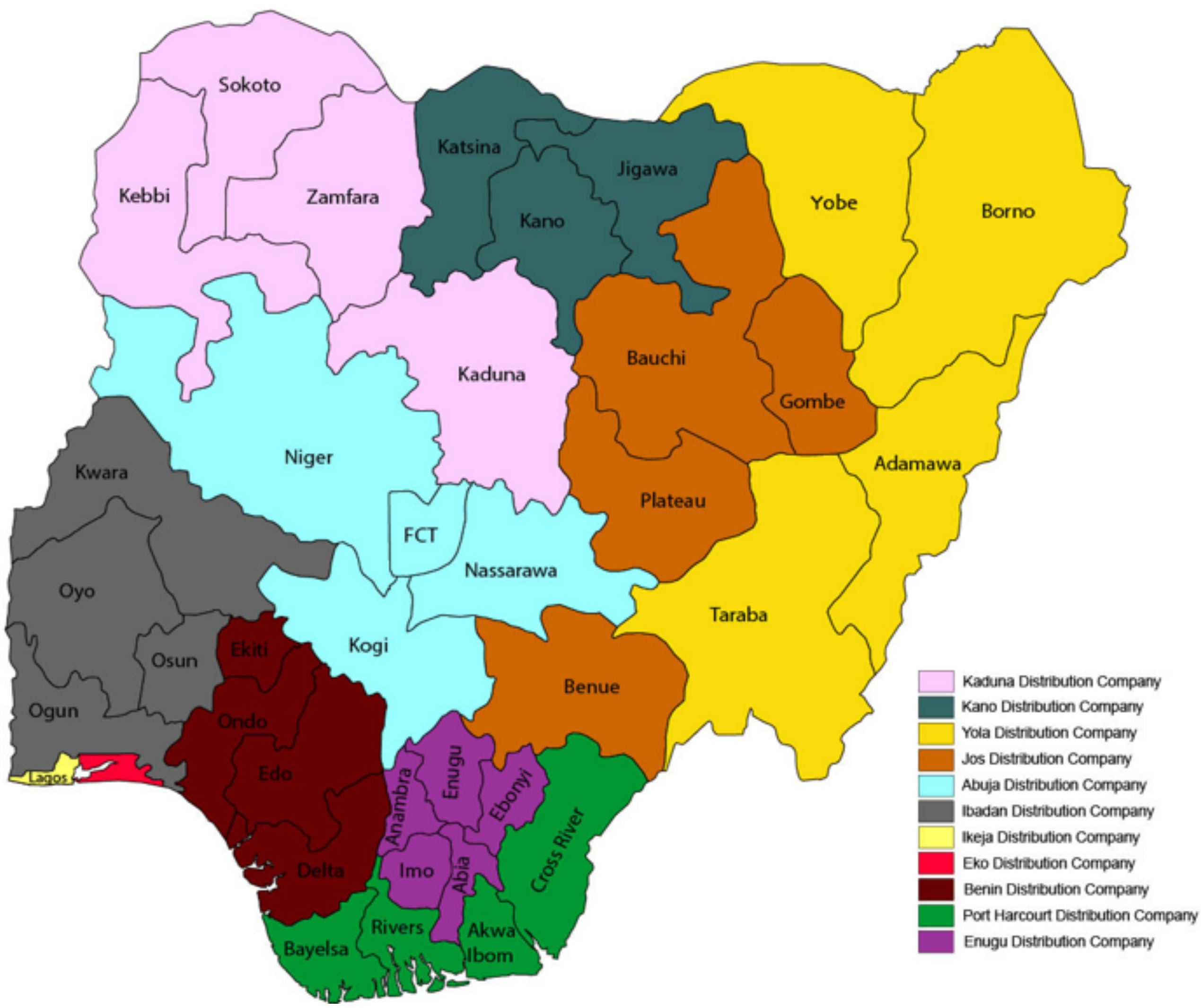


Figure 1: Map of research target area

There is a large tariff disparity between the discos. Some have the ability to get greater power from the grid and also reject it because they are over-supplied. Others have very limited access to the grid at all. In addition, some discos have long transmission lines across them, over which they have no control. In some cases, customers have to travel long distances to pay their bills and frequently pay to the wrong providers, which accept their payment fraudulently.

In effect, the discos resulting from the privatisation may be too large to control. So four questions need to be asked:

1. Is the geographical delineation of the discos the best option, or would smaller franchises be better to ensure a better service, particularly in rural areas?

2. Does the existing geographical delineation discourage efficiency, or at least hinder it?

3. Can the geographical delineation of the discos be changed to improve the interface between them and the generators to encourage reliability?

4. Can the current investors in the discos be persuaded that if they relinquish some of their franchise area there would be greater efficiency? And could more specialist discos be created, dedicated to better customer service in, say, rural areas?

The position of the transmission grid is important here. While there are 11 discos, the transmission system currently has eight transmission zones. The net result is that one disco may find itself in two transmission zones, while one transmission zone has more than two discos. This has produced a mismatch, which has led to stranded electricity from the gencos and much finger pointing. The fit may seem an ephemeral matter but it affects cash flow.

Did Nigeria choose the right model of privatisation?

The privatisation of the Nigeria power sector followed two Indian models, the Delhi urban model and the Odisha rural model. However, compared with these, Nigeria was inadequately prepared for some basic requirements:

- There was a need for a certain volume of available power to avoid a high tariff in the initial stages. This power was not available.

- To be successful, the privatisation needed to have a sizable percentage of its customers with meters. This would ensure that the newly privatised companies had an adequate income stream.

- There was a need for a detailed analysis of the disco and genco companies to predict their potential performance and this was not carried out.

In relation to the availability of power, it was obvious that the former NEPA did not produce enough and its performance was deteriorating. Investment in the sector was very low and far lower than that required by other countries before privatisation. Raising per capita consumption before privatisation was necessary if the subsequent privatisation was to succeed. The Federal Government had ventured into independent power plants in the late 1990s, and the Niger Delta Power Holding Company (NDPHC) was created in 2004 to increase generating capacity. However, few of these projects have actually come online. The combined 1,000 MW of the finished Egbema and Calabar power stations is idle for lack of natural gas and the infrastructure to deliver it.

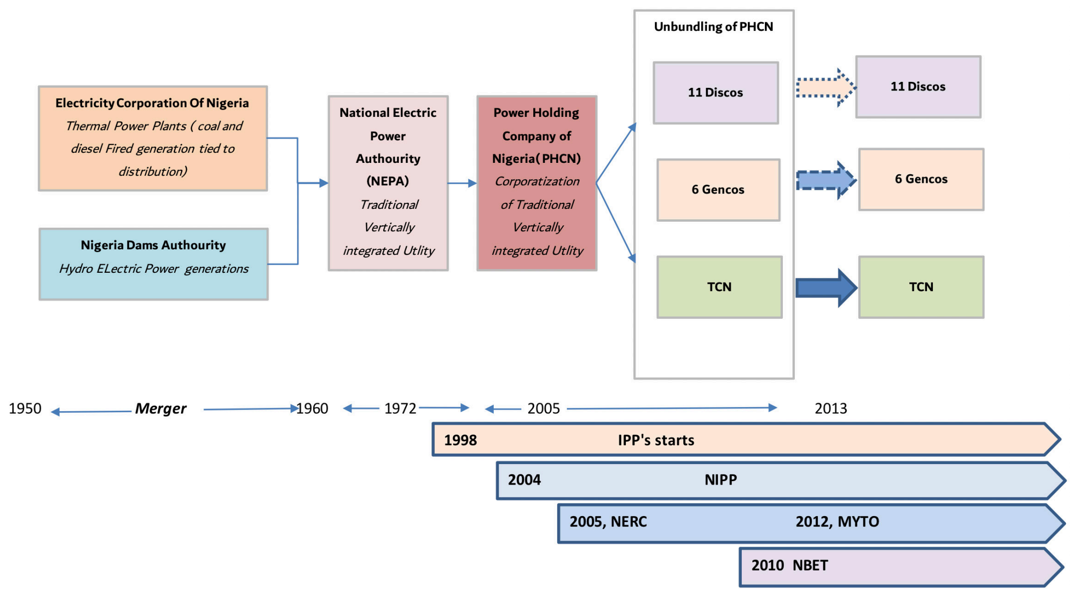


Figure 2: The Nigerian Power sector pathway

Metering is also a vital element in the value chain of the power sector because it gives confidence to consumers and to the investor regarding income. Without it, the utility has to rely on inaccurate estimations, while there may be under-billing, which masks the true cost of energy to the consumer.

Metering is thus vital to successful privatisation, as it creates accountability. While the Nigerian Government has instituted a mass metering programme, which would be regarded as a success if it reached 50% of consumers, this was not achieved before privatisation. A further factor was the transition from electro-mechanical meters where the bill was paid after the electricity had been delivered and the electronic pre-paid metering system. While the latter was an attempt to prevent stealing of power, there was little consumer education about it. The problem of 'willingness to pay' has continued to bother the sector, not least because of the level of 'bypassing' it.

Prior to privatisation, the basic details of the potential market were left without adequate analysis. The new companies had no 'baseline loss' analysis and so no clear idea as to how to reduce it. There was also no clear outline of the capital expenditure (CAPEX) and operating expenditure (OPEX) requirements needed in the first five years of operation. Furthermore, the new companies did not know how many customers they would actually have, which clearly affected the fixed charge element of the tariff, or indeed the need for further metering. Detailed studies were not carried out.

In fact, the losses of the discos were assumed to be between 35% for the good ones – Eko, Ikeja and Abuja – and 40% for the rest. There were no basic guiding metrics available.

Indeed, Nigeria copied the New Delhi model of privatisation without questioning whether it was fit for purpose. In practice the Indian model was split into two. In New Delhi, the privatisation was that of a city disco, while that of Odisha represented a rural area of India. Nigeria seemed to combine the two rather different approaches. The result has been an unfavourable difference in tariffs, where urban discos charge lower prices than rural ones.

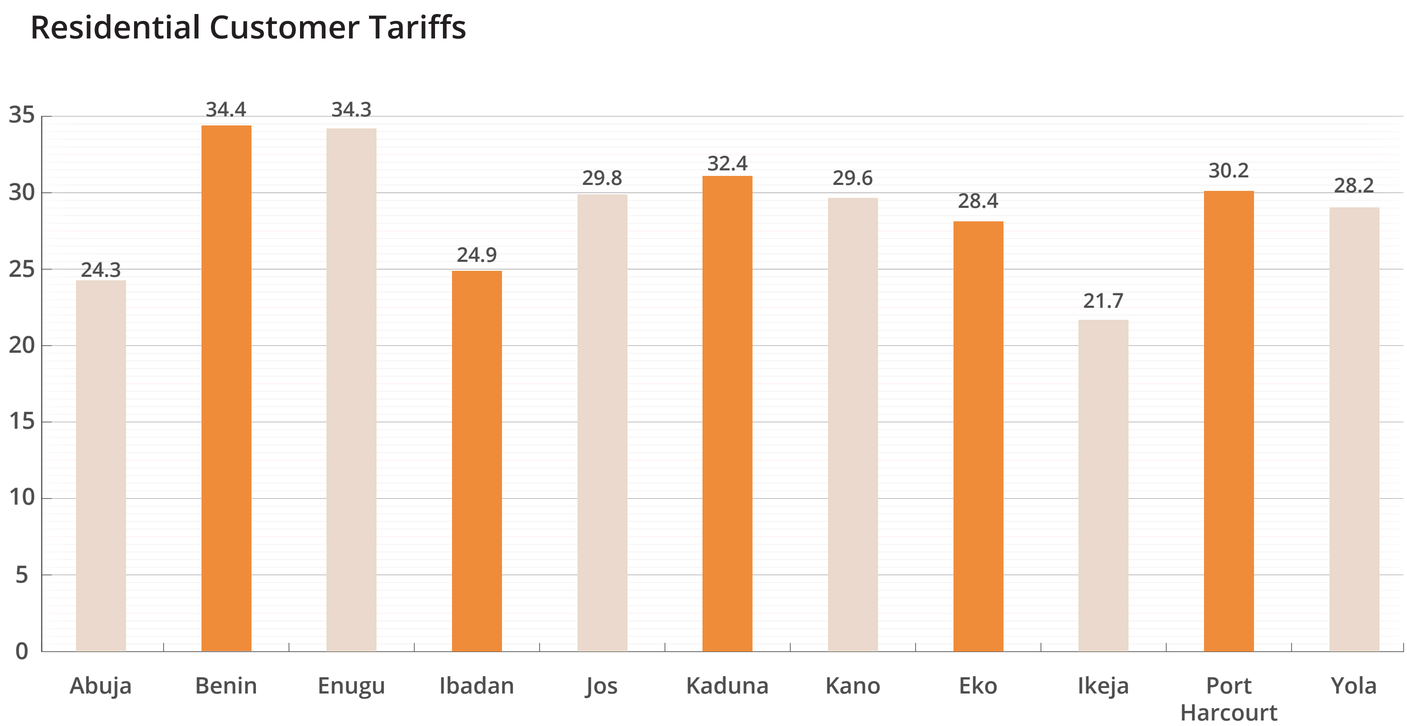


Figure 3: Variation in residential customer tariffs across the discos (Source MYTO 2015)

While the losses in the Indian privatisation did not make a distinction between collection losses and commercial losses, and combined them in the aggregate technical and commercial loss (AT&C), Nigeria separated them. Yet it did not harness the advantage, which would have emphasised the need to reduce the collection losses as the most significant element in their problems. Thus, while the system separated out the numbers, the bids from the companies failed to acknowledge that the immediate issue was the failure to collect payments from customers.

In addition, the Nigerian privatisation process failed to consider the question of subsidy. In practice the India Odisha rural privatisation failed without subsidy support and has subsequently succeeded after support was considered. In practice, there has been no Nigerian economic instrument to create investment in generation capacity and no obvious plan to develop transmission infrastructure as in India. There was a detailed plan in Nigeria, involving Manitoba Hydro as a management contractor, but it became mired in controversy for three years and there has been no adequate plan to match transmission expansion with the increase in generation.

The performance targets

The metrics for performance evaluation in the transaction documents is supposed to ensure the continuing performance of the investors in line with the regulatory regime. They provide business continuity in the case of failure or deviation from targets. Consequently, the actors in the value chain signed various contracts that defined their performance expectations. These included performance agreements, which set targets in loss reduction, metering, new customers and network expansion. For the gencos this set an annual capacity recovery target. The trouble was that there was a need to link the performance expectations of the discos with those of the gencos and this was not done.

Equally, in the shareholder agreements, the share of the government implied that the government was supposed to make the equivalent percentage investment to its shareholding size, if there was an equity call for funds. When this has not happened, other private shareholders have not added new investment funds and so the discos have not invested, with a bad effect on the whole sector.

Post-privatisation performance

While the privatised regime raised expectations for customers, investors and government, four years down the line, the discos have not only failed to meet their expected targets, but their baseline losses have mostly increased (see figure 4).

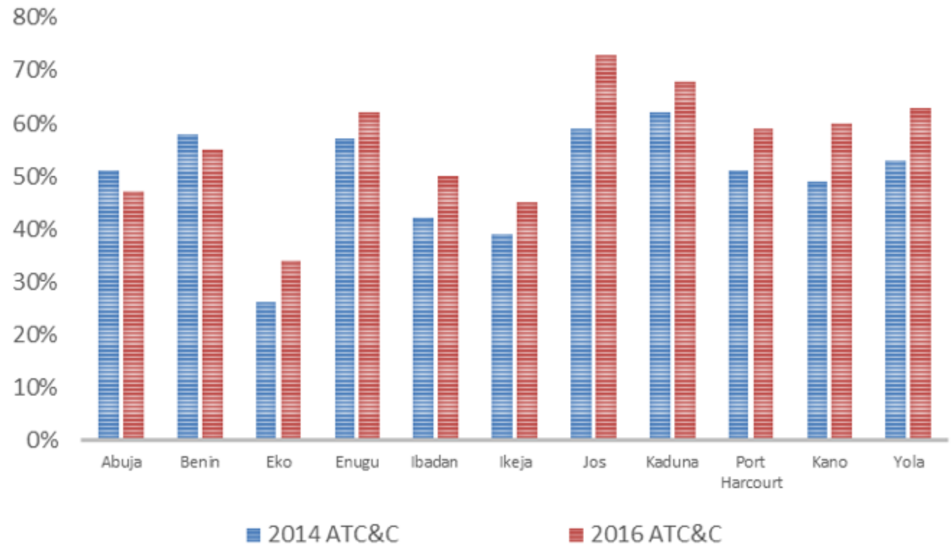


Figure 4 AT&C at handover compared with AT&C the end of year 2016; source ANED)

The metering target was expected to increase. However, the complaints about it have increased instead. Accidents on the line seemed to have increased as well, due to poor network reinforcement.

For the gencos, the expected level of investment in capacity recovery has not been met and little additional investment has been made. Actually selling their electricity has been a problem. This has been exacerbated by periods of gas pipeline vandalism, starving most of the generators of fuel.

All these factors indicate that while the regulatory approach may have been right, the regulatory approach cannot on its own ensure the success of privatisation. It has to be based on the right information and this in turn has to be made on realistic assumptions. Where power becomes the tool for industrialisation and economic liberation, as it usually is, mechanisms have to be put in place to support investments in the sector, avoid the shock of increasing tariffs, and spur production with cheaper power. It must also be monitored to avoid all the difficult issues that come with subsidies. What is lacking in Nigeria are technical partnerships, with experience, that can coach the discos on how to go about loss reduction.

Regulation, tariffs and contracting, and investment

Regulation – is this the best that can be done?

There are essentially two types of regulation of a privatised electricity system; a cost of service regulation and an incentive-based system. Broadly, the former system works when there is an adequate level of data on costs, which the regulator examines and sets a benchmark for. The incentive system requires the regulator to set a series of targets on collection, connections and output, which the utility strives to meet. When they meet them, they will benefit and if they don't, the investment suffers.

The purpose of these regulations is to moderate the behaviour of investors where there is effectively a monopoly market. For example, the Nigerian model specifically creates a situation where the distribution companies have no competition in their distribution areas. They and other sections of the market need to be regulated to prevent them gouging out 'unreasonable profits' or providing a substandard service. Measuring what is 'fair' in costs and profits is challenging in the best of environments, but becomes progressively more so where there is a lack of adequate data.

In Nigeria's case the incentive approach was adopted. This caps revenue, rather than tariffs, allowing flexibility in tariff design. However, the regulator can decide to treat costs in two different ways:

1. In the total expenditure approach (TOTEX) all expenditure is lumped together and the entity chooses to allocate any percentage to OPEX or CAPEX.

2. In the 'building block' approach, the regulator restricts the amount of investment that will be required for different costs. The requirement for CAPEX and OPEX are pre-determined and the cost structure is built from the ground upwards. This does not give the investor flexibility in the use of the cash. Rather it forces the investor to allocate a minimum requirement for each type of expenditure, according to the demands of the regulator.

Nigeria practices the second of these types of regulation, with the specific requirement that it forces the investor to meet the targets on performance and punishes them if they are not met. This regulatory regime is called the Multi-Year Tariff Order (MYTO). How this works in practice, as opposed to the original theory, has been identified as a major cause of the challenges in the electricity market. Yet the principle of MYTO may be the right choice. It worked well in Australia. The question thus is what did Nigeria not get right?

The principle of MYTO is based on the following ideas:

- That the distribution company is the only collecting agent in the sector and thus the market should be designed for the efficient flow of money from distributor to generator and finally the fuel supplier.

- That the tariff is therefore the sum total of all the costs of all actors in the value chain, divided by the energy that is supplied via the infrastructure. This implies that the more energy that can be supplied with limited infrastructure, the more affordable the tariff becomes. Consequently, the more customers will respond and the disco will be incentivised to reduce costs. However, the cost of the players in other sectors are in the control of the regulator, not the discos, thus making the regulator responsible for cost control. Ideally this should create an efficient cycle during which as more customers link up, the more the disco can reduce costs. However, the discos cannot control the way the gencos or the transmission system cost or provide their part in the expansion of the system.

- All this implies that the system gets better as it moves forward. The performance expectation trajectory gets translated as a loss reduction trajectory. For the discos this is the AT&C. For the gencos it is the expected capacity available. And for the transmission company it is the allowable transmission loss.

However, due to the inadequate collection system within the discos, the sector suffers from major cash-flow problems. This liquidity problem in the Nigerian Electricity Supply System (NESI) cannot be evaluated outside the regulatory model. NESI cannot be translated into its financial base without the MYTO system. This in turn cannot be fully understood in the absence of an evaluation of the risks relating to its contracts.

These links are illustrated by Figure 5.

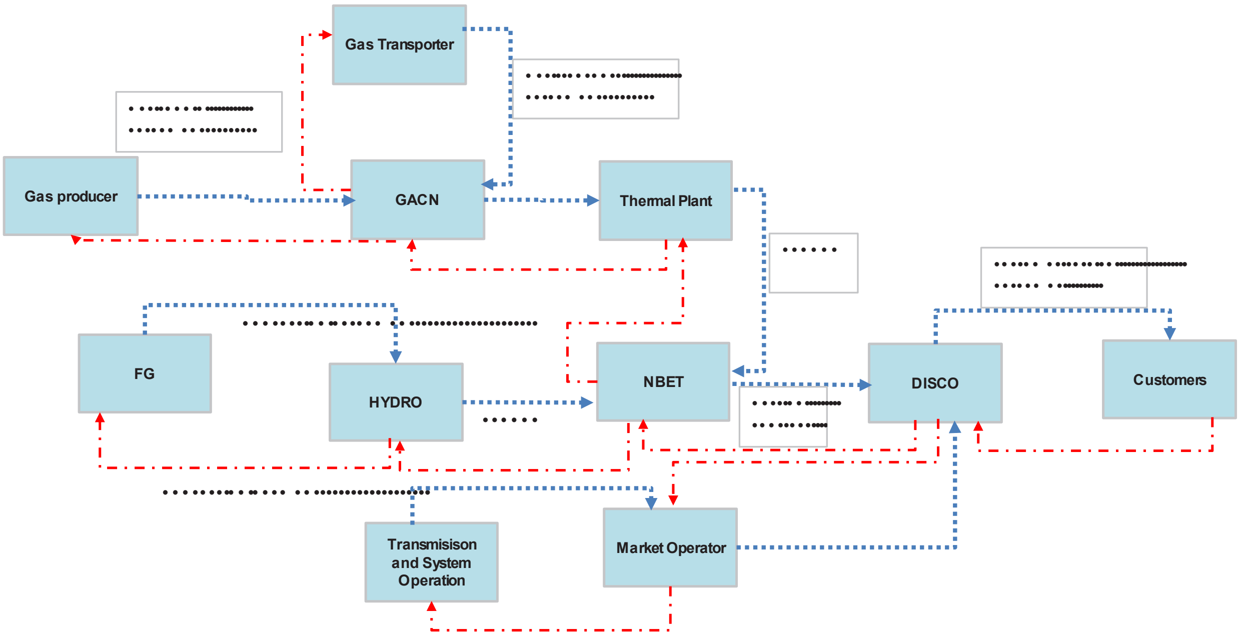


Figure 5: The contractual relationships in the sector

In many cases, where these contracts are not 'back-to-back', the mismatch provides considerable risks. If there is no mechanism to take care of these risks, then the kind of financial challenges currently confronting the industry arise. These can be devastating for any future plans across the sector, disabling investment that is critical for further progress. "Back to back' contracts create chains of liability from the operator to the subcontractors so that they are all required to play their parts on the same terms.

Such risks can be systemic and both structural and/or financial, affecting the whole system, and have largely been ignored in the Nigerian privatised sector. There have been various attempts to check these risks in recent regulations, but the impact still remains and has a considerable impact, with billions of Naira being lost on a monthly basis.

For example, the load allocation of the discos should have been based on projected demand, the growing economies of the areas concerned, and the number of anticipated customers, not to mention the available transmission capacity. Yet how the current disco load allocations are made under MYTO remain unclear. The direct implication is that there is a market shortfall in some areas, which is used to determine the tariff of these discos, while some discos are getting more power than has actually been allocated.

This market shortfall has consequences for both the market and for tariffs. If the tariff is not reflective of costs, or those costs have been 'sculpted' by being deferred, it is extremely difficult to recover them. Raising the cost of electricity, without a commensurate improvement in the quality of the service, is politically very difficult. Thus the Government interferes with the market tariff without a clear mechanism for recovering the shortfall.

At least part of the market shortfall is caused by the inadequate power generated in the system. In that lack of generation, there is less electricity to sell and reach the target used when the tariffs were initially set. Furthermore, as the generating system is 80% thermal, burning either natural gas or oil, the lack of a proper pricing mechanism for gas does not encourage the gencos to get as much gas from the IOCs as they could. The IOCs are happy to sell, but the current situation creates a vicious spiral in which less power is generated, less market remittances are received and the cycle continues downward.

Lack of back-to-back contracts

Detailed examination of the existing contracts shows inconsistency between them and, indeed, even within the same contract. For a value chain industry, like the power sector, the contracts should be transferred from one actor to another along the value chain until the right actor bears the risk. This is referred to as 'back-to-back' contracting.

In the gas market currently the contracts are 'take-or-pay' which favours the oil companies providing the gas. In effect, the generators are required to buy the gas regardless of whether it is actually need it, or it is available. Yet there is no security in place for gas transport, so when there is pipeline vandalism, or an explosion, all the risk falls on the discos. The power purchasing agreements (PPAs) between the generating companies and the discos are premised on these contracts, but there is no provision for the secure supply of the gas. In addition, the discos' contracts with the gencos do not have any punitive mechanism, if the discos fail to collect the amount of power they have apparently committed to receive.

In addition, the discos' contracts with the gencos do not have any punitive mechanism, if the discos fail to collect the amount of power they have apparently committed to receive, or the genco fails to provide it.

Furthermore, the amount of power in MYTO allocations that has been used to calculate the appropriate tariffs over the years is not in line with the gencos' 'capacity recovery'. This is the component of the tariff that is supposed to repay the investors in generating capacity.

In the case of the PPAs, the gas price is indexed to the dollar with the base case and the indexation escalation being almost unique to each contract. The escalation clauses vary from monthly to quarterly. Meanwhile the MYTO review is every six months. The implication here is that when an index changes in the price of gas, the disco has to borrow money constantly every month for six months to cover the difference in the dollar price, until the MYTO review catches up. Given the low gas prices put into the model initially, an increase was inevitable. This in turn assumes that the review will actually result in a tariff adjustment to match, which it may not do.

The PPAs also come with punitive interest charges for the discos, if they default on payments. This may have been intended to discipline the discos, but where they have been stretched by circumstances beyond their control, it threatens their survival.

The networks

Most of the systemic risk in the system lies in the transmission and distribution side of the sector. The more that this is reduced, the safer the system will be. This is because the value chain is only as strong as its weakest link. In a privatised system, this weakest point – the transmission grid – is always a natural monopoly, which is usually controlled by government for security reasons. To guarantee the reliability and sustainability of the whole system requires a detailed effort by the Transmission Company of Nigeria (TCN) to invest in a commercially informed manner.

Recently TCN has claimed that it is trying to transport more power, but the discos are not accepting the power generated. In this regard TCN claims to have 'wheeling capacity' or ability to carry 7,000 MW across its wires, but by explaining the problem in terms of the refusal of the discos to take more power, they have opened up a conflict between the discos and the gencos that is worrying. In fact, both TCN and the generators are both part of the problem and it cannot all be blamed in the discos.

How TCN came up with the figure of 7,000 MW is not very clear, at least to the other players. There has never been more than 5,100 MW distributed on the grid in any recognised period, so it may be the result of a simulation and thus theoretical. However, the discos still need to work closely with TCN to insure that investment in the grid actually goes where it is needed. This is vital for the future of the whole system.

Adding to this problem is the whole question of the inadequacy of the gas transportation system. The last time there was any major investment in this was in the late 1980s. The 'gas master plan' has yet to produce any projects. This poses a major risk that could seriously damage the whole electricity sector. Part of the problem is that the methodology of pricing gas transportation is not clear. The cost of $0.80 per Million British Thermal Units (MMBtu) is a black box. It is also not clear how the MYTO model assesses this transportation price, when there has been very little investment in it for over 20 years.

Thus while the discos worry about the cost of transportation without any tangible additions to capacity, the gencos would have preferred private sector participation in providing it. The current investment model for gas infrastructure leaves both the discos and gencos at the mercy of the Federal Government. This has done nothing, but still holds them accountable for their various performance agreements, based on a gas supply that is radically different from what was projected when they were privatised. It has become obvious that more gas and more stability of supply will be required to meet the MYTO power generation projections as they currently stand. Realism in both transmission and gas supply is thus fundamental and needs to be based on realistic plans. At the moment none of the tiers of power production, transmission and distribution are in sync with each other.

Risks and challenges

Risks

The proper assessment of risk in the system is the key to success across the whole value chain. Some these are easily identified.

1. Foreign exchange risks occur because a significant proportion of the industry's costs are indexed in US dollars. Typically, the discos use indexing if the currency of their revenues does not vary significantly from the currency of investment. However, when the currencies differ significantly, as happened when the Naira crashed, there is a need for another mechanism. The likely solutions range from subsidy to the development of hedging instruments.

2. Volumetric risk occurs because the tariff is predicated on a certain quantity of electricity sold. Where there is no fixed charge, the tariff is also supposed to cover the disco's fixed costs. This means that when sales fall in volume, there is less cash in the sector to cover sunk investments. There are three specific volumetric risks. The gas price varies so that international gas prices affect availability. As noted there are risks connected with gas transport and the uncertainty surrounding the supply of gas. This can only be solved by sharing this risk with suppliers and also the building up of better supply infrastructure and diversifying into other sources of generation, like solar. The third volumetric risk lies in the transmission system. The wheeling capacity of the grid must be sufficient and flexible enough to deliver the expected allocation to the discos, which will require expansion.

3. Regulatory risk: Cost recovery of power or gas is dependent on regulatory agreements being honoured. Poorly managed or unexpected regulation risk can lead to a lack of further investment as investors are afraid of the potential damage to their existing investment. The chances of regulatory mistakes come from a lack of independence of the Nigerian Electricity Regulatory Commission (NERC). Actors are potentially vulnerable to political influence, such as holding down prices in election periods.
   The limited knowledge of the regulatory leadership and its regular recycling is also a threat. The sector needs a knowledgeable regulator and this has not necessarily happened in the past decade, as illustrated by a number of U-turns. Furthermore, there is a conflict between the regulator, the judiciary and the Consumer Protection Council (CPC), with the CPC stopping customers from paying even when the regulator has ruled against the customer.

A further complexity is added by the environmental standards demanded by the National Environmental Standards, Regulatory and Enforcement Agency (NESREA), which may not be compatible with the cost structures assumed by the regulator.

4. Wider risk factors affecting collection relate to a lack of access to cheap funding support for CAPEX such as metering and network reinforcement. Combined here with contradictory messages from the courts, the regulator and the Government, this helps undermine the whole approach to tariff setting.

In effect, a failure to properly assess these risks creates a tariff model with wrong assumptions. The lack of back-to-back contracts does not help clarify this. The issue does not merely require greater clarity, but also considerable political will, to fix.

The industry revenue shortfall

The data input into MYTO that guides the sector is the principal contributory reason for the market and the tariff shortfall. It is effectively a massive calculation of costs and revenues based on detailed known data and assumptions. A key part is the description of the existing ‘market’ and its component costs.

The market shortfall arises from the simple fact that the data generated around 2012 was not in tune with reality. The generation load factors used in the MYTO, the assumptions made by it on the amount of generation and the weighted average cost of capital (WACC) were all inaccurate and that was just three data points.

The tariff shortfall arises when the discos calculate the assumed cost-reflecting tariff and realise that their customers may not be able to pay it. Consequently, part of the tariff is deferred to be collected in the future. Currently this is more than Naira 1 trillion.

Combine the market and the tariff shortfalls and they account to almost Naira 40 billion a month. Making a concerted effect to get a few data points right and putting in a few new regulatory instruments would go a long way to plugging this loss, but at a cost of a very significant upward revision in electricity tariffs in the short to medium term.

To look in detail at the assumptions in the MYTO is to see the problem:

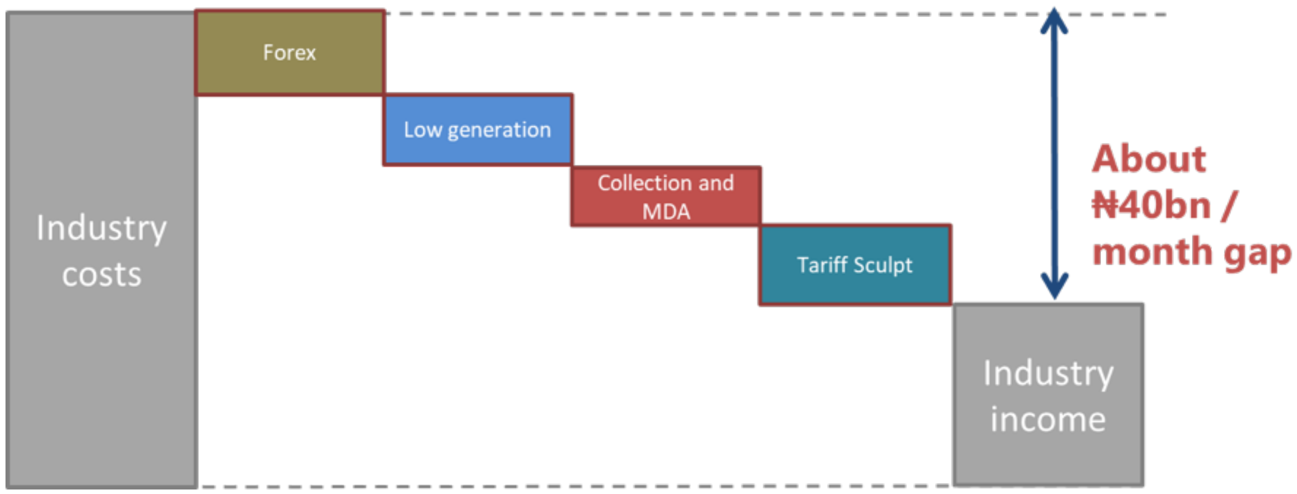


Figure 6: The components of the monthly shortfall in the NESI (source MYTO)

1. The foreign exchange (FX) assumption in the MYTO put the Naira at 198.9 per dollar. Not only was this far from reality, but the PPA agreements in the sector followed the National Bulk Electricity Trading (NBET) system which put the figure at not less that Naira 300 to the dollar, with it now around 360. This alone causes around a 30% increase in the cost of gas from the providers to the rest of the value chain. In the month of September 2016, the pass through of FX costs raised the industry bill from NBET from Naira 21 billion to Naira 28 billion. This kind of money cannot be borrowed from financial markets with any hope of repayment.

2. The WACC approach used in MYTO is catch-all. The real pre-tax WACC for generation, transmission and distribution is put at 11%. However, in reality the risk profile of these very different activities varies greatly. What is needed is a detailed benchmark study that determines how they differ.

3. The availability factor for generation needs to reflect reality. MYTO assumptions and the actual availability of power are very wide apart.

4. The cost of fuel in MYTO does not reflect reality either.

5. The CAPEX assumptions, in MYTO, is not only inadequate for transmission and distribution, but also needs to spur greater investment. The disparity between the CAPEX used in MYTO and the actual CAPEX required to meet the set target of 10 GW of transmission capacity in the time available is extremely large. Without an adjustment, there is no pathway to address the massive shortfall in transmission that actually delivers under 4,800 MW. The CAPEX required for distribution system improvement is similarly under-estimated. While the discos used the values in the MYTO to calculate their bids, the

FX shift has changed these assumptions overnight. Both metering and network shortcomings were under-estimated. Meanwhile a change in regulation demanding immediate metering of all customers came as a major unplanned cost. Clearly the CAPEX assumptions in the MYTO need to be reviewed.

Transmision Company of Nigeria (TCN) CAPEX (Nominal N '000)	**Transmision Service Provider (TSP)**	*56,000,000*	*200,944,000*	*412,901,000*	*264,160,000*	*246,736,000*
	Market Operator					
	System Operator		*4,181,000*	*5,603,000*	*1,043,000*	*1,092,000*
	Total Capex	*56,000,000*	*205,125,000*	*418,504,000*	*265,203,000*	*247,828,000*

Table2: MYTO CAPEX Provision for TCN

6. The OPEX assumption in the MYTO also needs reappraisal for transmission and distribution. It simply does not reflect the costs of running a network with dilapidated equipment, relatively unautomated systems and a huge staff base inherited from the pre-privatisation era, in spite of huge lay-offs of staff. There needs to be a call for more realism because this is one of the main reasons why the discos try to keep more money to themselves relative to market remittances, thus starving the entire value chain.

7. The generator parameters in the MYTO are also not in tune with reality. The available capacity and the load factor – the percentage generated compared with installed capacity – are set at levels of about 90%. This is not technically feasible. In reality, the actual amount generated versus the installed capacity is much closer to 40%.

8. The Aggregate Technical, Commercial and Collection loss (ATC&C) has two problems. First the loss reduction target set in the MYTO is unrealistic compared to other countries at the same stage of development. The second is that the breakdown of losses into the components of technical, commercial and collection losses and their attached targets are most unlikely to be achieved (Figure 7).

Figure 7: Expected loss reduction profile for the sector as committed in the MYTO

The tariff shortfall and cost reflective tariffs

Creating cost reflective tariffs requires a clear understanding from all the actors in the system. Here are a few salient points:

1. A tariff is cost reflective if all the "allowable frugal costs" of the sector can be covered through the tariff over the regulatory period.

2. The tariff does not need to be reflective in year one, but it must be reflective over the whole regulatory period. This implies that a disco can under-recover in the early years and over recover in the later ones. All the financial cost of the under-recovery must be passed through or converted into a regulatory instrument.

3. This creates a challenge. For the tariff to be cost reflective it has to be 'realistically frugal'. The OPEX should be related to the anticipated works in the franchise area as well as being bench marked against international standards. The CAPEX must be in line with required improvements and have a return on investment that is realistic.

4. The cost-reflective tariff must also be affordable. Government has a role to play here. It either needs to ensure that the available generation is in excess of demand to drive down

tariffs or, when part of the cost is considered unaffordable, it should be taken care of by subsidy, or government support.

5. A cost reflective tariff does not directly translate into liquidity in the sector. The pull between cost reflectivity and affordability creates the problem of tariff sculpting and this in turn explains the tariff deficit.

The deficit in Nigeria comes from the fact that the cost of the electricity structure is very high. The system has a lot of assets, many of them not actually functional, but considered valuable nonetheless, compared with the amount of electricity actually generated and used. Using this large amount of assets to produce very little energy leads to a very high Naira to kWh ratio. Thus either the assets need to be reviewed to reveal their actual value, or generation must improve before tariffs can start to come down.

In the meantime, there is a need for a support mechanism to ensure an affordable tariff. Crucially, there is also a need to rebase reality. With a significant part of the costs of the system likely to remain in US dollars, the value of the tariff needs to be understood in 2018 foreign exchange rates, rather than those of 2012, when evaluating the cost of new generation and infrastructure.

The implications of the wrong dimensioning of risks

The performance of the whole privatised sector so far has not been encouraging.

Generating performance has been challenged due to a lack of gas and the failure of the discos or the transmitter to take what they produce. The projections in the MYTO are largely overstated and there needs to be a policy change to ensure that generation meets targets that ease the liquidity problem.

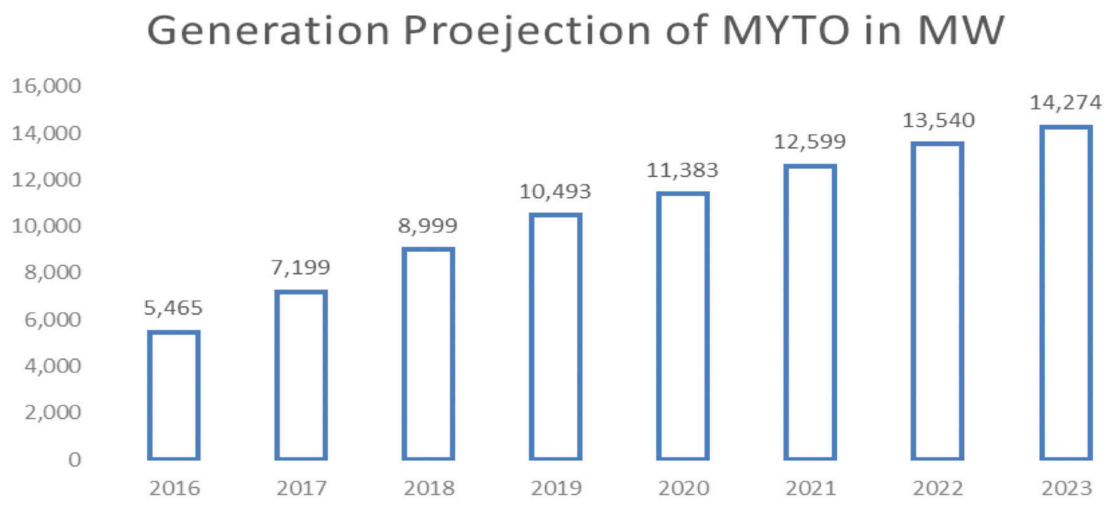


Figure 8: MYTO generation commitment (2015 model).

The data shows that available capacity is still far less than the theoretical capacity. Further investment is needed. However, even the declared available capacity is threatened by problems with transmission, or the availability of a transmission/distribution interface. Hasty investment in more power generation could easily produce little new change other than to further widen the gap between available power and capacity.

There are better alternatives:

1. The discos need to harmonise their captive generation within their areas. Estimates suggest that there is close to 300 MW of capacity generating capacity with more than 40% excess generation from these facilities. Given that this captive self-generation does not always work for 24 hours, the excess available could be as high as 67%. If this power can be purchased by the discos and sent to premium customers, more grid power could be made available elsewhere.

2. Off-grid solutions would also be useful for areas where long distribution lines give rise to high technical losses and low voltage in rural franchises.

The list of generation capacity in table 3 does not include new capacity like the recently finished Azura project, or the newly licensed coal and solar generation. There are also a number of embedded plants coming on. The recent announcements on the Mambilla Hydro project, Taraba State would add more than 3,000 MW in the mid-term. The NERC suggests that close to 13,000MW has been licensed, but is yet to be built. If so, the assumptions used in the feasibility studies for both generation and transmission may need to be reviewed as circumstances may well have changed.

Generator Name	Fuel Type	Theoretical Capacity (MW)	Capacity Available (MW)	Average Capacity Generating (MW)			
				2013	2014	2015	2017 first qaurter
PHCN successor Gencos							
EGBIN	Gas	1,320	1,030	604	473	584	580
AFAM IV-V	Gas	600	178	38	25	1	60
SAPELE	Gas	1,020	135	46	47	64	39
TRANSCORP POWER	Gas	972	373	188	319	322	353
GEREGU I	Gas	414	284	113	102	124	71
OMOTOSHO	Gas	335	168	60	104	166	97
OLORUNSOGO	Gas	335	168	57	129	175	88
SHIRORO	Hydro	600	565	283	223	207	256
JEBBA	Hydro	570	570	303	285	232	219
KAINJI	Hydro	760	199	100	67	199	196
Sub-total		***6,926***	***3,670***	***1,792***	***1,774***	***2,074***	***1,959***
Operational NIPPs							
ALAOJI NIPP	Gas	1,074	497	3	1	86	121
OLORUNSOGO NIPP	Gas	675	462	100	127	131	6
SAPELE NIPP	Gas	450	249	136	95	104	85
IHOVBOR NIPP	Gas	450	360	71	175	129	84
GEREGU II(NIPP)	Gas	434	434	102	127	133	130
OMOTOSHO NIPP	Gas	450	268	195	130	149	125
OMOKU	Gas	250	120	0	0	0	13
GBARAIN	Gas	225	113	0	0	0	60
Odukpani NIPP (Calabar)	Gas	561	120	0	0	35	53
Sub-total		***4,569***	***2,623***	***607***	***655***	***767***	***677***
IPPs (on-grid)							
IBOM POWER	Gas	190	170	4	47	55	120
AES	Gas	270	250	152	41	0	0
AGIP (OKPAI)	Gas	450	450	320	360	302	355
SHELL	Gas	650	650	366	391	346	385
TRANS-AMADI	Gas	60	0	0	0	0	60
Sub-total		***1,620***	***1,520***	***842***	***839***	***703***	***920***
ON-GRID TOTAL		**13,115**	**7,813**	**3,241**	**3,268**	**3,544**	**3,556**
IPPs (off-grid)							
OMOKU IPP	Gas	150	150	78	53	0	23
TRANS-AMADI	Gas	60	24	1	0	0	0
GEOMETRIC POWER (ABA)	Gas	132	0	0	0	0	0
NESCO (Jos) - Island	Hydro	30	21	24	24	18	12
OFF-GRID TOTAL		**372**	**195**	**103**	**77**	**18**	**35**

Table 3: Generation in Nigeria – a high-level view

The table clearly shows that there needs to be improvement in already installed generation to ensure that installed capacity really does match available capacity and that finishing up existing IPP projects could lead to more generation. Yet this in turn demands a realistic timetable to ensure that the stranded capacity is eliminated.

Transmission needs a well-planned effort to reinforce the network, which would boost investor confidence. It needs network improvement to voltage profile, strengthening and overall load capacity. It also needs highly targeted expansion.

There are clear indications that TCN has at times made attempts to do the right thing. This is evident in the first detailed expansion plan by Manitoba Hydro before 2016. Its detailed plan would scale the network from 4.5GW to 10GW, then 13GW and finally 20GW. The plan was not only designed to be technically feasible, but also commercially viable. The objective was to attract private investors, as it was obvious that the Federal Government budget could not fund this leap forward by itself (see Table 4).

Item	US$ m	MW target	TCN date
Capital refurbishment	$947m		2015
Projects under construction	$989m	7-8,000	2015
Expand to 10 GW, increase reliability	$2,235m	10,000	2017
Expand from 10 to 13 GW	$1,570m	13,000	2018
Expand from 13 to 16 GW	$1,000m	16,000	2019
Expand from 16 – 20 GW	$1,000m	20,000	2020
Total 2014-18	$7,742		

Table 4: The TCN expansion plan

However, this plan did not take off. Since 2016, TCN has put forward numerous expansion plans, the latest of which is supported by the World Bank. The newly appointed NERC leadership has commissioned a study of the interfaces between the discos and TCN, after all sides blamed each other. This new study may be an indication that all of the expansion plans to date have come from incorrect data and should be re-evaluated.

Such a re-evaluation would need to evaluate the gap between the discos and TCN and study the cost of closing it. It also needs to examine the potential for disco expansion, looking at whether such expansion is commercially viable to avoid yet more stranded assets. It would also need a plan for sources of funding, as currently the provision for TCN via the budget has not been adequate. Equally, the participation of private investment has to be encouraged, to bring in much-needed capital.

Indeed the whole position of TCN could be reviewed. It needs to be trusted by the other players. It could be properly unbundled into:

- An independent system operator, which is Government-owned for security reasons, but managed by a private service provider.
- This provider could be concessioned or put in a framework for private participation as a means to get the required money into the infrastructure.
- Or a market operator that will operate the market for the available grid.

Policy here might be to shift towards extra high voltage transmission links from the Niger Delta where fuel sources are abundant to areas in the north and east.

In the distribution sector, the discos have a poor record. The reasons range from the fact that the discos keep asking the Government to fulfil their own part in the obligations that make up their performance agreements, to the glaring fact that they have not made commensurate investments in the four years since taking over their concessions. Investment was a fundamental requirement in the bid process. They are now in a bad state, both physically, with dilapidated networks, and financially.

For a start, they are not created equal in terms of demography and local economies. In practice it might have been better that the privatisation process should have started in Lagos State. If this had happened the lessons learnt could have been translated outward to other regions, not necessarily using the same model, as in India.

This idea is supported by the graph in figure 12, which shows the composition of the discos. It can be clearly seen that Eko and Ikeja have a lot of industrial customers and Abuja lots of commercial ones. Jos and Port Harcourt are in a particularly bad state, as they are predominantly residential consumers, with little commercial and industrial load. The implication of this is that tariffs are skewed to be lower in States that are economically well off, where inhabitants can ironically afford to pay them. Poorer States have higher tariffs.
The 'sculpting' of the tariffs by the poorer discos to overcome the limited number of reliable

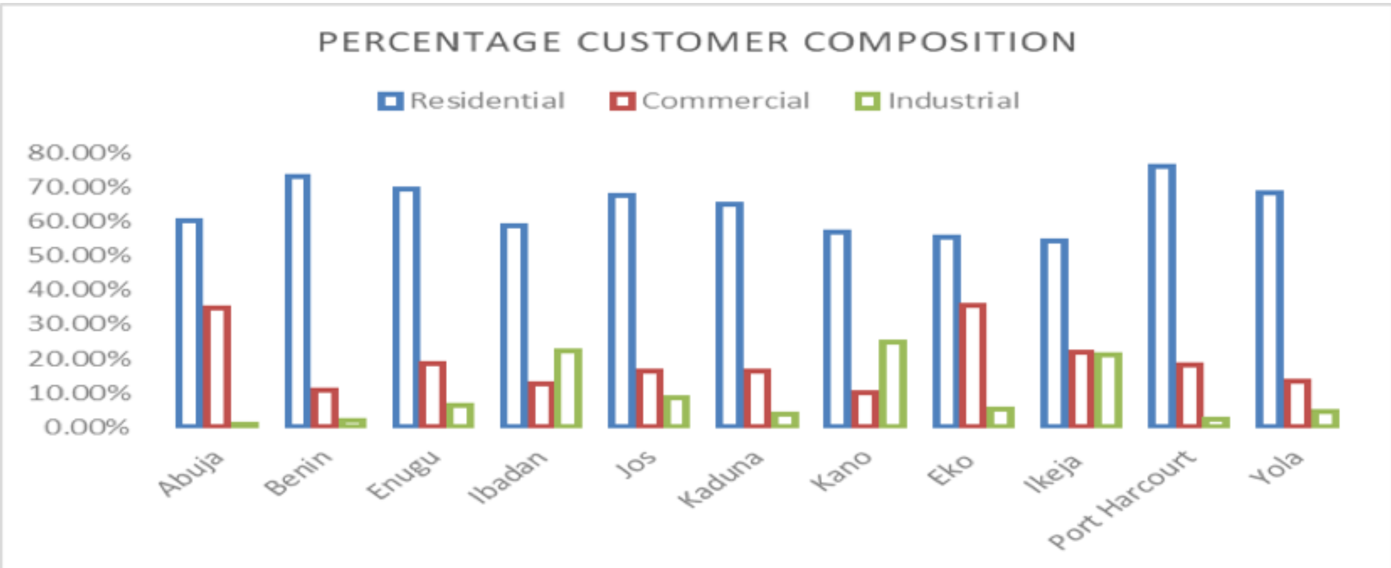


Figure 9: Percentage customer composition for discos (MYTO 2015 model)

customers shows that these power regions, with low affordability and a high sense of entitlement, still have higher tariffs in spite of very deep sculpting. The situation is made more complicated by a significant number of areas where Government has effectively been paying the bills for the limited amount of power that is received. This is a primary cause of the liquidity crisis aided by the low collection efficiency of the discos concerned.

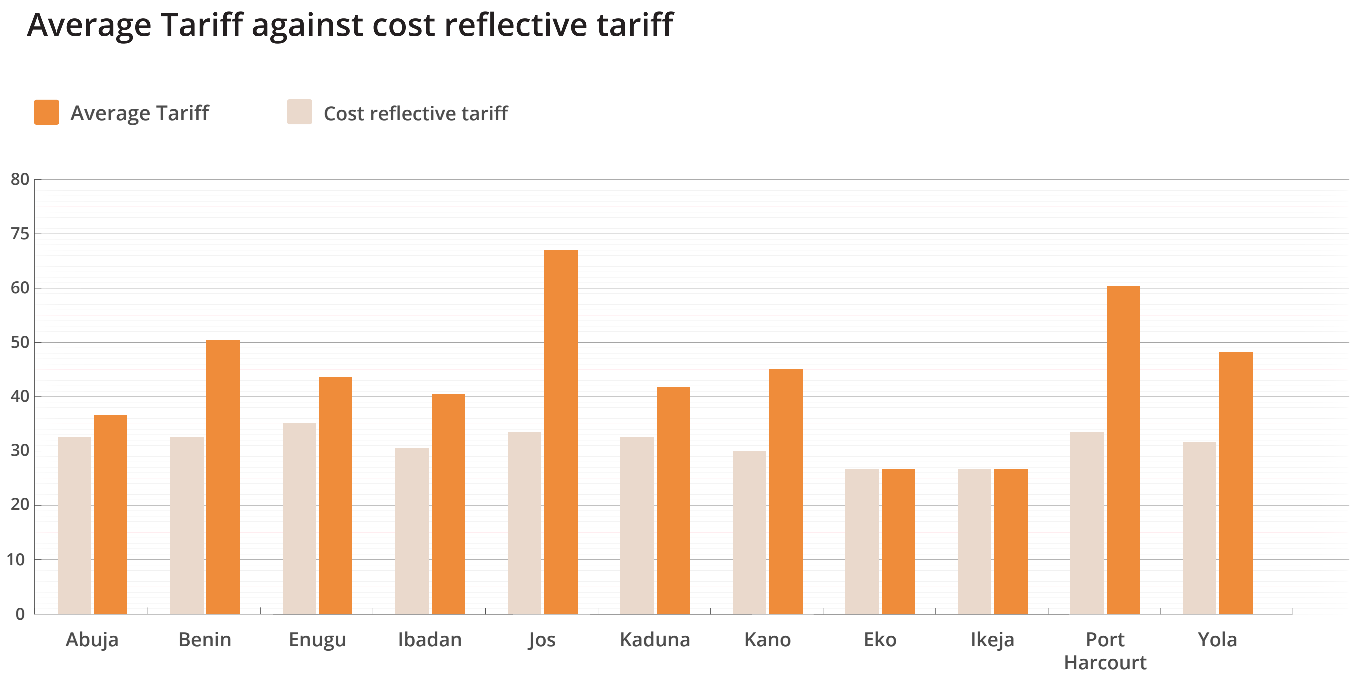


Figure 10: How discos average tariffs are related to cost reflective tariffs (MYTO 2015)

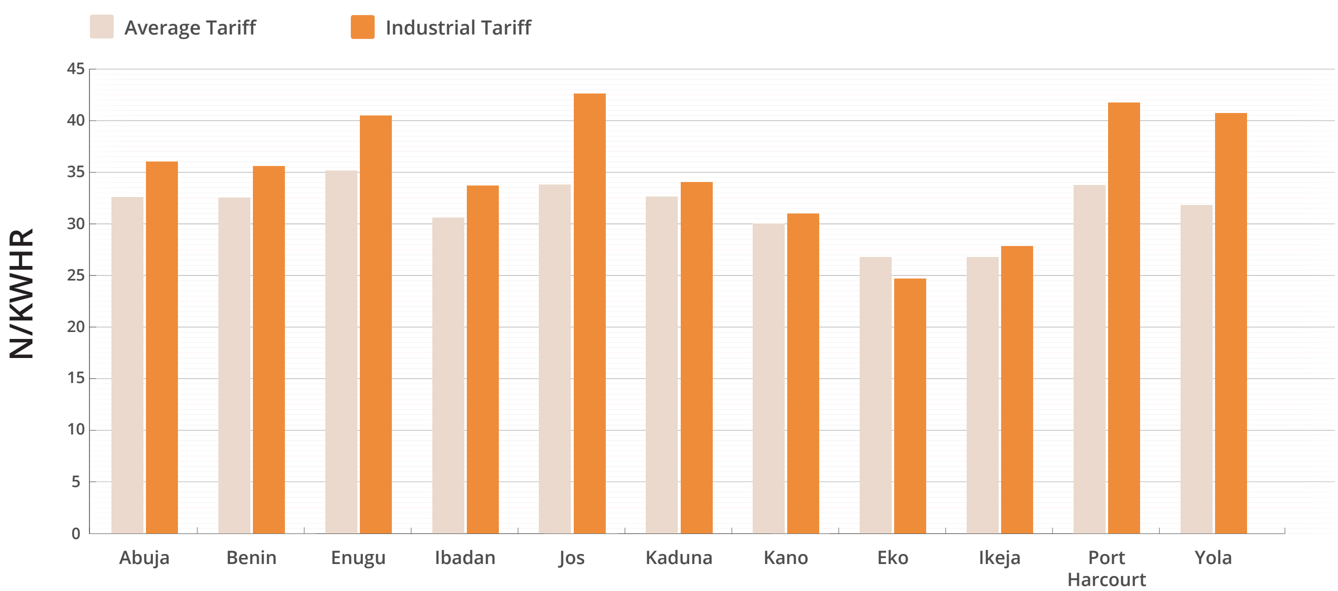


Figure: 11: The average tariff compared to the industrial tariff (DIS) showing the level of cross-subsidy (MYTO 2015)

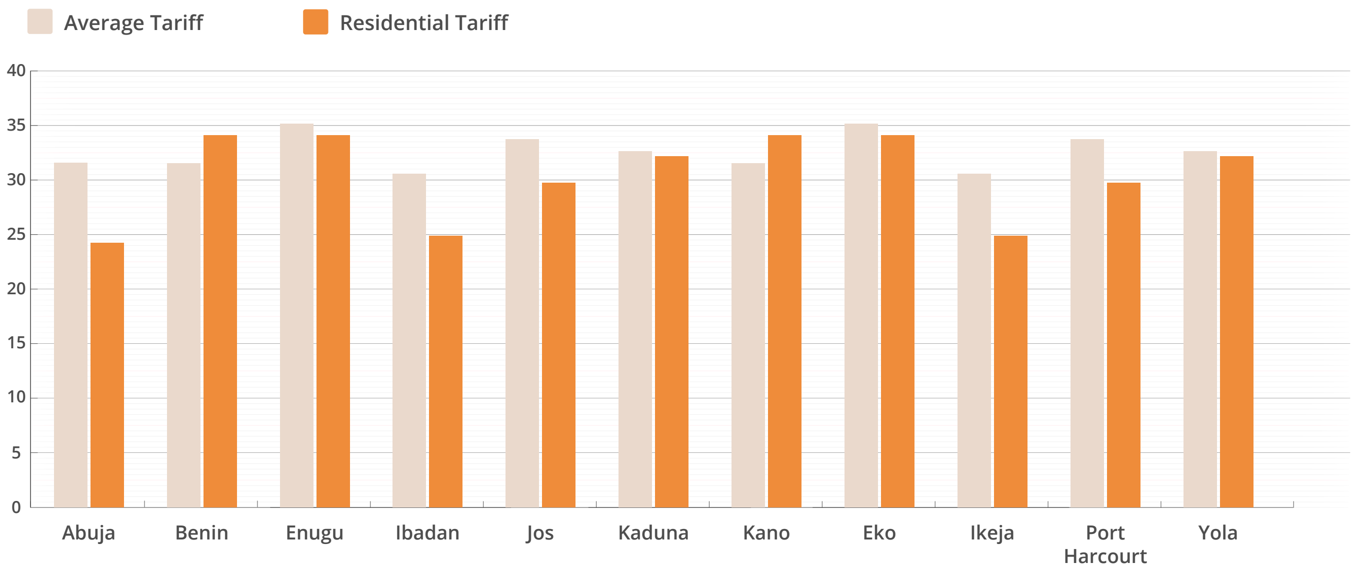


Figure 12: Average tariff compared to residential tariff (R2T) showing subsidy to residential class from other classes (MYTO 2015)

A review of other countries that privatised the sector – Chile, Argentina and India – shows that the level of performance by the private sector seems much higher than in Nigeria. One glaring omission in the request for proposals (RFP) in Nigeria was the lack of a requirement to have a technical partner which owned a similar franchise elsewhere. These technical partners should have had an equity commitment not less than 5%. In Nigeria's case, while few had such technical partners, when they did they made no equity contribution. Without such technical support, the loss reduction commitment of the new discos was almost impossible to achieve.

Table 5 shows the loss reduction commitments by the Nigerian investors relative to their CAPEX provisions in Table 6. It is obvious that the AT&C commitment was more than could be delivered at the level of CAPEX outlined in the MYTO.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5
Abuja	31.50%	23.80%	7.10%	10.90%	15.50%
Benin	18.00%	20.00%	22.59%	25.00%	20.00%
Enugu	0.63%	25.30%	28.37%	36.47%	43.33%
Ibadan	16.00%	18.71%	20.43%	19.84%	16.61%
Jos	10.30%	9.04%	11.01%	17.82%	24.21%
Kaduna	33.00%	37.00%	38.00%	38.00%	38.00%
Kano	15.00%	23.00%	25.00%	22.00%	15.00%
Eko	27.00%	26.93%	20.94%	10.16%	3.77%
Ikeja	25.70%	26.90%	28.95%	18.50%	9.20%
Port Harcourt	15.00%	17.50%	20.00%	20.00%	17.00%
Yola	25.17%	16.14%	13.81%	12.06%	8.85%

Table 5: Loss reduction commitment year on year by the discos (MYTO 2015)

Capex in Billions of Naira	2014	2015	2016	2017	2018	2019	2020	2021
Abuja	5.75	4.60	4.60	4.60	4.60	4.60	5.75	5.75
Benin	3.82	3.05	3.05	3.05	3.05	3.05	3.82	3.82
Enugu	4.28	3.42	3.42	3.42	3.42	3.42	4.28	4.28
Ibadan	6.89	5.51	5.51	5.51	5.51	5.51	6.89	6.89
Jos	3.57	2.86	2.86	2.86	2.86	2.86	3.57	3.57
Kaduna	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70
Kano	4.77	3.82	3.82	3.82	3.82	3.82	4.77	4.77
Eko	7.09	5.67	5.67	5.67	5.67	5.67	7.09	7.09
Ikeja	9.22	7.38	7.38	7.38	7.38	7.38	9.22	9.22
Port Harcourt	4.01	3.20	3.20	3.20	3.20	3.20	4.01	4.01
Yola	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06

Table 6: CAPEX required to reduce the losses (MYTO 2015)

This compares with the privatisation in New Delhi by Tata, where the privatisation was a success (see Figure 15). The CAPEX commitments by Tata are itemised in Table 6.

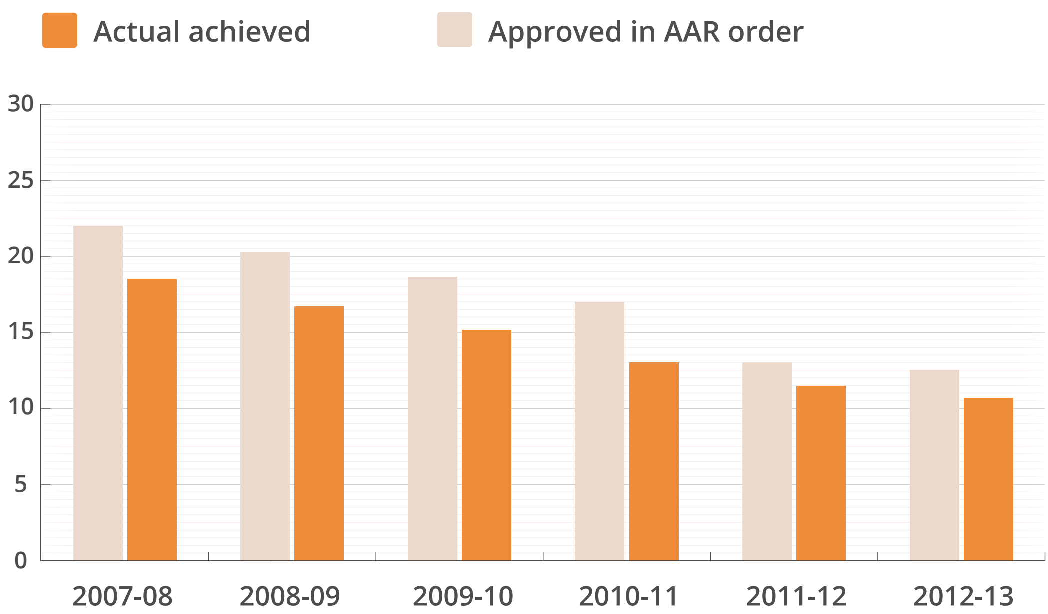


Figure 15: Tata New Delhi loss reductions (TERI-Public-private partnership in electricity distribution, case study of India

By comparison, with Tata, the Nigerian discos can never meet their obligations through this tariff model.

	FY 03	FY 04	FY 05	FY 06	FY 07	FY 08	FY 09	FY 10	FY 11	Total
AT&C loss reduction	0.1	1.2	1.7	2.4	1.6	1.9	2.5	2.1	1.7	15.1
Reliability improvement	0.2	2.4	1.7	1.7	0.5	0.7	0.4	1.6	2.0	11.1
Load growth	0.4	0.9	1.9	2.6	2.1	1.3	1.7	2.0	3.7	16.7
Infrastructure development	0.1	0.2	0.4	0.5	0.3	0.3	0.3	0.5	0.4	2.8
Total	0.8	4.7	5.6	7.2	4.5	4.1	4.8	6.2	7.8	45.7

Table 6: CAPEX commitments of TATA in New Delhi (TERI - Public-private partnership in electricity distribution, case study of India)

DISCOS

The true state of the discos

The state of the discos clearly shows the need for serious intervention. The investment of the last four years has been virtually insignificant. Outside Abuja and Benin, transmission and collection losses have been on the increase rather than falling. These should have been falling by now, but table 7 shows their trajectory. The interim figures for 2017 are believed to be worse.

ATC&C	Actual		
	2014	**2015**	**2016**
Abuja	51%	49%	47%
Benin	58%	56%	55%
Eko	26%	35%	34%
Enugu	57%	61%	62%
Ibadan	42%	49%	50%
Ikeja	39%	43%	45%
Jos	59%	66%	73%
Kaduna	62%	66%	68%
Port Harcourt	51%	57%	59%
Kano	49%	53%	60%
Yola	53%	58%	63%

Table 7: Comparison of the ATC&C performance of the discos (ANED)

While the lack of proper customer service, worsened by poor generation and inefficient distribution is the source of these high losses, the problem is a vicious circle. Poor generation leads to poor supply and the customers refuse to pay an additional tariff for 'darkness' leading to poor collections. This in turn limits the appetite for new investment and the payment to others further up the value chain.

This challenge of collection efficiency would have been less if the discos had made revenue assurance and metering a fundamental priority immediately after privatisation. Four years later, a total revenue assurance programme and a dedicated metering infrastructure is still an urgent need for the success of the whole sector. Year on year collection efficiency is outlined in Table 8.

With these high losses and the toxic relationship between the discos and the gencos, the discos' running costs increase every year in the absence of investments and automation. Equally, the discos cannot borrow because of their bad financial status. As a result, the discos tend to keep more than their fair share of what little customer payments they receive. The remittances to the bulk trader, NBET, has been so bad that the sector would have had to shut down without the intervention of the Federal Government in 2015 (see figure 13). It injected more than Naira 280 billion to bail out the discos and made the gencos only modestly less insolvent.

	Collection efficiency		
	2014	**2015**	**2016**
Abuja	71%	64%	66%
Benin	56%	67%	54%
Eko	82%	74%	74%
Enugu	58%	62%	69%
Ibadan	71%	63%	62%
Ikeja	73%	69%	69%
Jos	52%	41%	32%
Kaduna	52%	41%	43%
Port Harcourt	60%	49%	45%
Kano	64%	58%	49%
Yola	53%	57%	51%

Table 8: Collection efficiency performance of the discos (ANED)

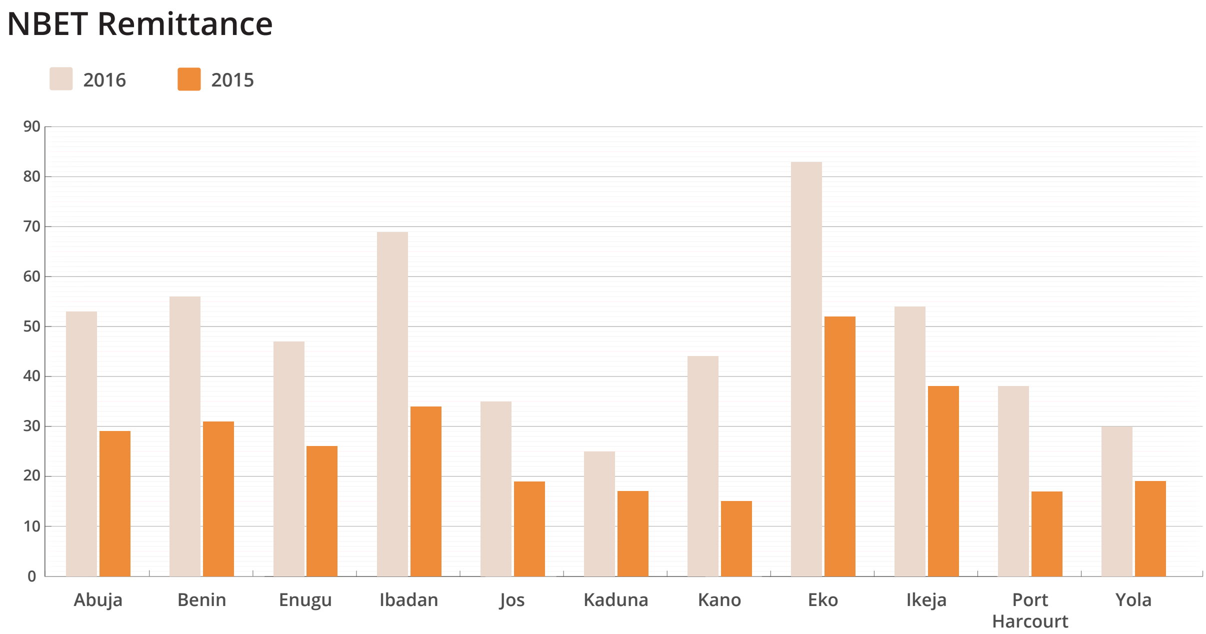


Figure 13: Disco obligation payments (NBET/MO Market Report 2017)

The current lack of back-to-back contracts and the needed regulatory reviews have led to a shortfall of close to Naira 1 trillion, making it plain that the emergency funding will be quickly consumed. The entire sector needs reform, but the real effort has to go into the discos. The five cardinal areas for improvement – ATC&C, reliability improvement, demand growth with metering, investment in the system and relative expansion

The discos claim that they have started a few significant metering projects, yet NERC's analysis of the data shows that projects are lagging, or sometimes not yet rolled out at all (Tables 9 and 10).

Distribution Licensee	Customer Population	CAPMI 2013-2016	Disco Funded Meter 2013-2016	Total New meters 2013-2016	Metering Obligation per year	Obligation to be met (by end of 2016)
Abuja	862,696	49,775	2,506	**52,281**	96,000	235,719
Benin	771,226	101,640	11,987	**113,627**	264,000	678,373
Enugu	442,201	61,527	9,494	**71,021**	204,000	540,979
Ibadan	809,829	1,396	376	**1,772**	48,000	142,228
Jos	1,474,364	150,766	36,000	**186,766**	217,611	466,067
Kaduna	835,736	-	60,852	**60,852**	120,000	299,148
Kano	384,691	63	3,578	**3,641**	100,000	296,359
Eko (Southern Lagos)	641,582	17,016	32,553	**49,569**	187,200	512,031
Ikeja (Northern Lagos)	472,453	-	2,182	**2,182**	100,000	297,818
Port Harcourt	488,600	24,888	40,868	**65,756**	252,000	690,244
Yola	293,478	3,725	1,360	**5,085**	51,600	149,715
Totals	**7,476,856**	**410,796**	**201,756**	**612,552**	**1,640,411**	**4,308,681**

Table 9: Metering performance of the discos (NERC's metering review 2017)

Distribution Licensee	Customer Population	Total Metered in August 2017	Percentage of customer Metered	Metering Gap as at August 2017
Abuja	862,696	450,041	52%	412,655
Benin	771,226	535,935	69%	235,291
Enugu	442,201	268,558	61%	173,643
Ibadan	809,829	224,445	28%	585,384
Jos	1,474,364	609,604	41%	864,760
Kaduna	835,736	467,578	56%	368,158
Kano	384,691	187,415	49%	197,276
Eko (Southern Lagos)	641,582	238,901	37%	402,681
Ikeja (Northern Lagos)	472,453	162,664	34%	309,789
Port Harcourt	488,600	237,188	49%	251,412
Yola	293,478	69,282	24%	224,196
Totals	**7,476,856**	**3,451,611**	**46%**	**4,025,245**

Table 10: Metering gap of the discos (NERC)

These unimpressive results show that the discos have not made sufficient effort to collect the money that they are billing and also mostly use estimated bills. Interviews with field officers suggest that they do not understand the methodology involved in estimating bills. While some discos have modified the methodology to include indicators of demand like the size of houses, it is clear that the lack of accurate billing data has led to overcharging some customers making collection increasingly difficult.

Because the discos are primary collectors of revenue for the whole sector, measuring the credit strength shows the status of the sector generally. The World Bank recently carried out a critical analysis of the discos to test the need for support in the sector. This showed that all the discos are already on negative equity and are effectively bankrupt. An Altman Z-score analysis of the companies showed that all the distribution companies are insolvent.

Regulation, transparency and liquidity

Regulatory Policies and Government

The policies of NESI backed by the independent regulator clearly need to be re-examined. If the overall policies are bad, no amount of regulatory change will succeed. Equally, politically motivated policies are also likely to be detrimental. It is worth looking at the EPSR Act itself and the policies behind it and the shortfall in rule-making by the NERC. In practice the faults do not lie in the overall plan, but in the lack of adequate data to underpin it.

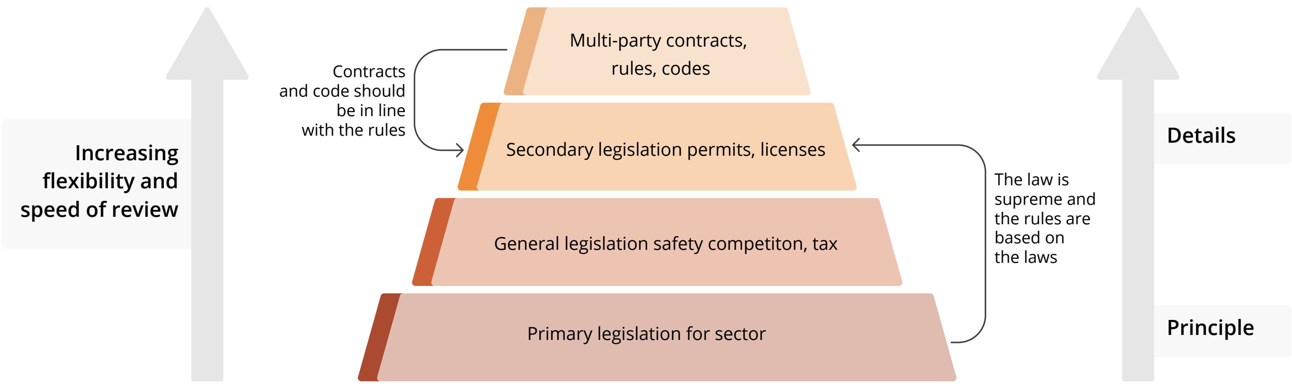


Figure 15: The Regulatory Framework model

The normal regulatory framework is to have primary legislation, leading to general legislation as in figure 15. The Electric Power Sector Reform Act (EPSRA) of 2005 sets out the principles for regulation of the entire sector, establishes NERC, and prohibits the distribution of electricity above 100 kW without a licence. NERC is given the task of ensuring that the prices charged by licensees, including the discos, are fair to consumers and sufficient to allow for reasonable earnings for efficient operations.

The features of the EPSRA are as follows:

- A detailed approach to dealing with the initial holding company that predated privatisation and an outline of the successor companies to be sold.
- The process of transfer of assets and liabilities of the defunct NEPA.
- The development of a competitive market framework from pre-privatisation to post-privatisation.

- The approved standards for licensing and tariff methodology.
- The process of acquisition of land and rights of way.
- The approval of consumer protection and licensee performance standards.
- Competition and market power issues.
- The procedure for consumer assistance.
- The rural electrification fund and its management.
- Other sundry changes as are seen necessary during the privatisation process.

While the regulatory functions of the NERC are many, clearly the process of setting approved tariffs is the most important as it directly affects the population. The Act envisaged this and laid out the principles of the methodology to be used. This was that it should:

- Allow an efficient licensee to recover the full cost of its business and get a return on capital.
- Provide incentive for continued technical and economic efficiency improvements.
- Provide incentive for continued improvements in the quality of the service.
- Give economically efficient signals about the cost of electricity.
- Avoid undue discrimination between consumers.
- Phase out or reduce cross-subsidy.

A review of the MYTO methodology shows that it could have satisfied these requirements. However, because of wrong assumptions in the data inputs and political interventions on the role of the regulator, the MYTO does not allow sufficient cost recovery. Nor does it send out the necessary market signals. The lack of strong regulation of transmission and targets for the system operation, do not send an economic signal to create improvements. The differences between the residential tariff amongst the discos show a tolerance for discrimination and the existing MYTO model creates heavy cross-subsidies.

Transparency and the law

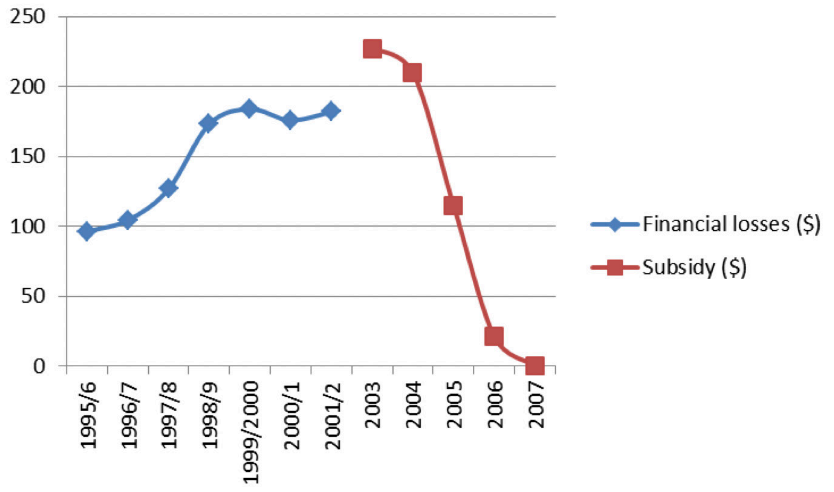
The system has raised accusations about who shares the greatest responsibility for the widespread failure of the system after 10 years of ‘reform’. Such accusations are a symptom of distrust. The discos accuse the Ministry of Power of delaying the appointment of a truly independent leadership for NERC and there has been a delay of more than a year after the tenure of the last leadership expired. Appointing senior personnel to the regulator seems to take a long time.
The gencos accuse the discos of keeping more than they should from bill payments. The Ministry appears to believe that the situation will improve in the future, while the regulator has kept quiet about a sector review and kept its old parameters, which is the cause of the liquidity issues in the sector as a whole.

All these have culminated in the exploitation of lacunas in the Act. One glaring issue in the Act is its lack of specificity on the chronology of actions and timelines. For instance, the Act is silent on the process of transition to an electricity market and when it should be declared to have arrived. It does not state how support for the sector should evolve. More recent moves by the Government, such as NERC’s move to redefine eligible customers, have been met by the discos’ response that the sector is not mature enough for it. In any case, such moves could be the final straw for discos, given their financial position.

Furthermore, NERC’s changes have eroded the trust of the discos in fair rule-making. They argue that such changes are premature and damaging. Clearly the system needs some regulatory reform to restore hope and a more holistic policy.

Potential support to the power sector

Support to the sector could come in a variety of forms. Various support systems could lead to a more efficient service. Support from State Governments and the use of the Rural Electrification Agency (REA) could help disco network expansion. In a nascent system like that of Nigeria is there a need for support in terms of the financial requirements needed? Will the consumer be able to pay for a proper ‘cost reflective tariff’ and if not, what is the most efficient way of introducing subsidy without market distortion?
The New Delhi privatisation was performing very badly until the introduction of subsidies, but crucially these were reduced as the situation improved (see figure 16).



FY	2003	2004	2005	2006	2007
Amount released	227.33	210	115	21.33	0

Figure 16: Tata New Delhi subsidy injection (TERI- Public-private partnership in electricity distribution)

The lack of any subsidy in the NESI has led to the need for the Federal Government to inject Naira 213 billion to save the sector, introduce a clean balance sheet and start the real transition to an electricity market. However, the freezing of the R2 domestic tariff shortly afterwards and the failure to align the data in the model, still produced a shortfall to the tune of Naira 1 trillion.

In 2015, NBET wanted to take care of the mismatch in the FX pass-through of the PPAs and the shortfall that resulted from the discos not passing it on. However, this was not accepted by policy makers. This pass-through is estimated to amount to Naira 701 billion, according to the bulk trader and represents an effective subsidy to the discos at the expense of the upstream of the whole sector.

However, this make-shift approach does not solve the problem. What is needed is a more detailed approach, that entails a gradual reduction in this hidden subsidy until the sector is mature enough to do without it, as in the Indian case. What maturity means in this case is adequate investment in the sector, enough power to wheel and an adequate power mix. In effect, the system will not work as a proper market without considerable targeted investment from government and a change in policy.

There are a few immediate steps that the Government could take. It could reduce the gas price by giving up some or all of the percentage of the royalty it gets from gas production, thus reducing prices. This could also be applied to the concession fees for water in hydrogeneration.

These two measures alone would go a long way to reduce the wholesale price of power. Furthermore, the amortisation of the Transmission Company of Nigeria (TCN) assets can be back-loaded to reduce the transmission Use of System (TUoS) charge, with Government support, or more probably with concessions at a lower fee. This too would reduce the wholesale price of power.

Recently, a couple of States have embarked on a few generation projects. River State and Akwa Ibom State were at the forefront of these. However, a network to confine the power in the States concerned was not there, nor was the metering facility required to collect the money from customers, either. Most of the power had to be sold to the grid.

Akwa Ibom State has recently started work with the Port Harcourt Electricity Distribution Company (PHED) to design a 132kV ring that will confine the power generation of Ibom power to Uyo. It has also been pushing for better metering in the belief that ring-fenced customers will pay for the meters.

Welcome though this is, in other cases there have been major projects by the States to introduce new distribution lines and substations, without actually talking to the resident discos. The States and the discos need to reach out to each other, particularly in rural areas.

This is also an issue for the Rural Electrification Agency. It has a well-grounded management that believes in transparency. However, the critical ingredient here is the integration of the rural electrification plans and the expansion plans of the discos. This has to be on the understanding that rural electrification cannot be achieved on the present tariff system. The discos need support to expand into non-profitable areas.

This problem is clearly frustrating to the Ministry of Power, because the discos are refusing to accept power because they fear they will not be able to collect the money. This has led to the Ministry's declaration of 'the eligible customer'. This will allow big load takers of more than 2 MWh to have a bilateral direct agreement with the gencos. They can enter Power Purchasing Agreements (PPA) with the gencos and have a TUoS with the transmission or distribution company directly. This gives an opportunity for the gencos to reduce their level of stranded power. The Ministry believe that this will create further investment in new capacity once they see real payments on the horizon.

However, if the discos are not rejecting as much load as is suggested, this opportunity may disappear. What is really needed for the future investors in new generation for 'eligible customers' is a very detailed analysis of the sector before they put up any more money.

In relation to metering, customers want to pay for what they actually use, not an estimate. Yet the regulator believes that improving the CAPEX requirement for the discos will not actually go directly to metering. The quick fix here might be to unbundle the metering service from the disco. This would give an external funder for the meters, while the responsibility for revenue assurance remains with the discos.

One of the oddities of the system is that the institutions of higher learning in the country are clearly in need to power and the discos understand this. They provide power for at least 20 hours a day. Yet the Government has decided to build dedicated solar power plants for them. The economic case for this is unclear. The power will be expensive and will displace that provided by the discos, which have heavily invested in dedicated lines. It will also deprive the discos of reliable payers. There has been no apparent dialogue about this.

Theft

Nigeria currently has no law about electricity theft. It might have been expected that this had been in place for a long time, or at least before the 'eligible customer' regulation. The regulator is working hard to get a regulation on this. Feedback from the discos indicates that they want a very heavy punitive charge that will deter customers from stealing. What is certain is that the advent of such a law would go a long way to help the entire power sector.

Summary of approaches to tackle the liquidity crisis

There are clearly a large number of solutions on a number of fronts for both Government and the private sector. Policy targets have to be far more focussed, progressive and sequenced.

A detailed survey of government agencies and the discos have produced results that are in tandem with the observations of the World Bank Report "Making Power Affordable in Africa and Viable for its Utilities".

These policies focussed on:

- Improving the performance of the utilities by focussing on the quality of service in the short run, with good customer care, faster responses to outages, more vending places and credit management solutions in metering.

- Efficient loss reduction and better estimation of bills where there are no meters.

- A proper methodology for measuring reliability.

- A proper mechanism for cost recovery.

- Avoiding a rise in tariffs with outages and targeting of subsidies for improving the system.

- A detailed revenue protection system approved by the regulator.

- Small and infrequent tariff increases to avoid tariff shocks.

- System optimization though detailed 'least cost' expansion plans.

- Addressing theft through a special legal system, training the judiciary in the problem and harmonising the positions of NERC and the Consumer Protection Council on the issue.

The major challenge in financing the power sector is the lack of patient capital. The acquisition costs of privatisation have put such great pressure on the investors that the smooth running of the discos has been severely hampered. This has also affected the gencos, reducing their ability to invest in capacity recovery or expansion.

The power sector needs finance with peculiar characteristics. It needs to be long-term and highly committed. It is highly leveraged and long-term, with syndicated loans, multi-currencies and requires detailed back-to-back security. Recently the Nigerian pension fund has been available and qualifies as patient capital for the power sector, but needs proper security to unlock the potential of the industry.