TRANSITION TO BILATERAL CONTRACTING.

APPLICATION FOR RATE RESET TO SUPPORT CONTRACTUAL OBLIGATIONS

FOR IKEJA ELECTRIC

Date: 6th July 2023

Contents

1. Executive Summary:

The NERC tariff review process was designed with the intent of undertaking major reviews every five years. Additionally, an extraordinary tariff review is triggered when a Disco requires additional investment beyond the permitted capital expenditure, or when unforeseen operational, legal, or regulatory costs need to be reasonably passed on to consumers. Minor reviews are also scheduled every six months to adjust tariffs based on changes in gas prices, foreign exchange rates, generation output, and inflation. However, the tariffs are consistently falling below cost-reflective levels because the parameters are not aligned with the current reality of the business putting pressure on Discos and government to subsidize the tariff gaps. This undermines the Discos' ability to fulfill their obligations under the Performance Agreements and Vesting Contract and exacerbates the liquidity challenges in the electricity sector.

Ikeja Electric (IE) is primarily responsible for distributing electricity to the mainland area of Lagos (Lagos North) and certain parts of Ogun State. Our objective is to enhance the quality of life for our customers by providing reliable power and delivering excellent customer service. At present, we serve approximately 1,081,418 active customers and employ around 4,131 dedicated staff members, including both permanent and outsourced employees.

Over the past five years, Ikeja Electric has consistently experienced revenue growth of 148%, going from N68.3 billion in 2017 to N169.64 billion in 2022. This growth can be attributed largely to increases in the amount of energy delivered (from 3,366 GWh to 4,082 GWh) and increase in weighted average tariffs (from N43.30 in 2017 to N53.10 in 2022). Our network has suffered many years of under-investment (both before we took over the business and subsequently). For many years, it has not been possible to raise the capital to invest because the tariffs did not reflect the cost of serving customers and we have not even been able to meet our own minimum operational costs or pay the generators who supply us in full. To improve service delivery, IE procured additional energy via a bilateral contract from Egbin Power in 2016, securing 100MW from its unit 6 to augment the grid supply; a financial relationship that is adversely impacted by the consequences of non-cost reflective tariffs.
Even now, the proposed migration to full bilateral power purchase arrangement will only be possible if we can transition towards a cost reflective tariff that recognizes the additional capital expenditure over the current MYTO provisions to deliver these improvements. We welcome the

fact that NERC intends to put the industry on a path to sustainable tariffs that will support the whole sector.

Together with NERC embarked on a Performance Improvement Plan in 2020 with the following objectives:

- Increasing the total energy supplied across our network from the 2019 levels of 4,249 GWh/ year to 7,209 GWh/ year by December 2024:
- Increasing the average duration of supply for our customers in each tariff band over the same period.
- Reducing the average frequency of interruptions from 5.6 per day in 2019 to 3.6 per month by December 2022.
- Reducing the average duration of interruptions from 12 hours per day to 8 hours per month by December 2022.
- Reducing the average response time to calls from 1 minute to 30 seconds by December 2022.
- Reducing the average response time to resolving complaints from 12 hours per day to 8 hours per month by December 2022.
- Maintaining a constant service voltage level of 11kV and 33kV across all our feeders.

The planned PIP projects on our network were to expand capacity in line with our demand growth, replace assets and deploy state-of-the-art technology to improve the efficiency of our operations. These investments include metering infrastructure and technical infrastructure upgrades. Metering infrastructure upgrade costs include the cost of reconductoring LV lines, insulators cross arms, changing of wooden poles to standard concrete poles and reconductoring undersized lines to standard 150mm lines. Technical costs include radiation of new feeders to relief overloaded feeders, rehabilitation work on the feeders, costs of replacing feeder pillars, costs of breakers and panels, fencing of DTs and remote monitoring. To deliver value for money in our investments, we have used a robust procurement process. We had recognized the timelines to deliver the investment within our planning process.
Despite the well robust performance improvement plan, key challenges such as delayed CBN fund release, the lack of a cost reflective tariff, hyperinflation, eligible customer declaration, customer apathy to payments, energy theft and meter bypass continue to deter the successful implementation of the plan and our ability to attain our set goals. The challenges in the industry

are daunting, the stakes are high, but we are determined to succeed, hence the need for this reset.

Our long-term goals and objectives are to continually be the front runner in the electricity supply industry and to be the reference point across Africa as the epitome of success in the electricity distribution space this can only be achieve with the support of all our Stakeholders.

1.1. Description of some of Ikeja Electric's achievements

- By strengthening the distribution network, we were able to reduce the frequency of electric service interruptions to our customers by 62% compared to 2013 levels.
- Established an improved organization structure to set the foundation for the business transformation we hope to achieve in the coming years.
- Established a state-of-the-art customer care infrastructure that has a fully integrated Customer Relationship Management (CRM) application for managing customer complaints and requests.
- Implemented an improved organizational model that was geared towards increasing the number of customer touch points to drive better customer service experience for our customers while reducing costs and promoting greater efficiency in our operations.
- Implemented an upgrade of our customer service infrastructure to further improve our customer service track record.
- Centralization of billing operations as a means of driving more operational efficiency and reducing losses.
- Over 4,000 MD meters were installed (2,844 meters were at the DT level, 300 meters (both incoming and outgoing feeders) were installed at the 11kv feeder level; 493 MD meters) while 29,633 Non-MD meters were installed.
- "Oshodi Model BU project", which was designed with the aim of ensuring exceptional service delivery and operational efficiency through the deployment of the people, processes and technology required to improve the overall customer experience. This model has also been expanded to Shomolu Business Unit, transforming the business operations and customer experience.
- Expansion of platforms for customer engagement, which included the introduction of the Live Chat platform.

- Continued Customer Enumeration, Technical Audit and Asset Mapping exercise (CETAAM)
- Over 98% metering of distribution transformer within our network.
- Deployment of a new estimated billing methodology to address complaints from customers, helping to reduce customer complaints recorded on estimated billing by 21.5%
- Success completion of both the Occupational Health and Safety Assessment Series (OHSAS) 18001:2007 and ISO 9001:2008 Stage 1 Audit in 2016. Achieving OHSAS 18001:2007 and ISO 9001:2008 certifications in 2017.
- Business process automations such as Mobi works application, Estimated Billing Methodology EBM software, Meter Reading software, Outsourcing of debt collection.
- Successfully executed the Debt-for-Metering scheme, metering over 23,000 customers.
- Reduction in ATC&C losses from 38.6% in 2017 to 31.8% in 2018
- Established and inaugurated functional i-Empower (QHSE Academy) to help develop in-house safety leads (Safety Leadership Team) companywide.
- Launched Beyond Zero, Take Ownership programs and i-SAFE App for easy and faster escalation of hazards.
- Installation of 2,516 meters to achieve 100% metering of feeders, DTs and MD customers in 2018.
- Introduction of third-party franchise operations for management of customer service, payment channels in 2018.
- Successful establishment of a fully operational customer care unit with walk-in centers; call centers, on-line chat with our customer service operatives.
- Customer enumeration, asset mapping and metering as well as AMI metering of 32,295 customers to ensure improved energy accounting and maintenance of assets throughout the network in 2019.
- Successful roll out of Bilateral Power Service agreement with communities such as Magodo, Shonibare Estate and Ikeja GRA in 2019, with 20 locations as at date
- Introduction of 116 young Engineers through the Young Engineers Program to strengthen the technical workforce.
- Implementation of electronic bill delivery to customers in 2019.
- Implementation of the Meter Asset Provider scheme as directed by NERC, with over 437,000 customers metered under this scheme to date.

- Successfully completed our metering allocation under NNMP 0 within stipulated timelines, with over 111,703 metered under this programme.
- Embarked on Vendor Financing options for customer metering, over 10,000 meters acquired to date under this scheme.
- In order to improve ATC&C (Aggregate Technical, Commercial, and Collection) levels, deliberate revenue protection activities, and technology upgrades. These measures have been specifically targeted at significantly improving ATC&C levels from 38.62% in 2017 to 23.42% in 2021. In 2022, we achieved the lowest recorded ATC&C level of 19.6%.

Despite the achievements and plans, Ikeja Electric's journey towards self-sufficiency, sustainability, and profitability has consistently encountered hindrances due to mismatch between our current realities and MYTO projections, certain factors. Some of these factors can have been mitigated going forward if the regulated tariff model is reviewed to reflect the critical reality requirement for service delivery and sustainability.

1.2. The primary objective of this report

The objectives of this are to ensure the following:

1. Sustainable provision of energy to customers while maintaining the operational viability of Ikeja Electric and the Nigerian Electricity Supply Industry (NESI),
2. Improving Ikeja Electric's performance across all efficiency and grow metrics.
3. Positioning the business to attract the needed investment to grow and move into sustainability and profitability.
4. Safeguarding investors funds and ensuring return on investment of existing and potential investors and partners
5. Transition to full bilateral contracting with GENCOs is sustained by ensuring recovery of full cost from tariff to meet full obligations under this regime.

To achieve the above, this report proposes a review of:

a) Major factors incorporated in the tariff structure.

b) weighted average tariffs that accurately reflect the expected service levels to be provided to customers.

c) overall efficiencies within the business to improve customer experience.

The key drivers to be considered for this review includes:

- Evaluation of energy levels in line with the existing and planned infrastructure across our network.
- Addressing Aggregate Technical Commercial and Collection (ATC&C) loss targets
- Assessing Capital Expenditure (CAPEX) requirements for improved performance
- Examining Operating Expenditure (OPEX) adequacy for improved performance.

2. Evaluation of energy levels and Projections:

Energy assumptions rely on the generation capacity projections in the July 2023 MYTO Model. For IE, this means an average of 6,670GWh over the next six (6) years. However, we are leveraging the opportunity provided by the Commission to engage and sign specific bilateral PPAs with our GenCo partners, as well as TCN, to ensure the availability of energy for IE. We have also undertaken a comprehensive state-of-the-network study to ascertain the likely demand and investments (CapEx and OpEx) necessary to deliver energy to our customers in a sustained manner while recording minimal loss (ATC&C) levels. Although, the average energy levels received from TCN to Ikeja Electric since 2015 have fluctuated between 3,808GWh and 4,500GWh and have not significantly met the MYTO energy level target set over time.

Table 1a: CAPEX 5 Years Historical Performance

5 Years Historical CAPEX Analysis: MYTO Projections vs Actuals							
	2018	2019	2020	2021	2022	TOTAL	Remarks
	=N='m	=N='m	=N='m	=N='m	=N='m	=N='m	
MYTO 2020	-	7,377	7,377	7,377	9,222	31,354	IE focused on network strengthening, projects that will drive delivery of sustainable energy to the customers, such as Overhead Line Construction, Distribution / Line Transformers, Power Transformers and Sub - Station Equipment. To improve ATC&C; investment in metering, IT infrastructures and field monitoring via operational vehicles to improve field logistics and revenue protection activities, were executed in the last 5 years.
IE CAPEX Investment	=N='m	=N='m	=N='m	=N='m	=N='m	=N='m	
Plant and Machinery	3,641	4,007	12,243	7,219	14,101	41,211	
Operational Vehicles	136	265	0	106	48	557	
Buildings	165	204	17	109	172	667	
Furniture and fittings	244	223	206	162	184	1,019	
Computer equipments	231	235	169	145	109	889	
Total IE CAPEX Investment	**4,417**	**4,934**	**12,635**	**7,742**	**14,615**	**44,343**	
Variance	**4,417**	**(2,443)**	**5,258**	**364**	**5,394**	**12,990**	

For periods 2018 – 2020 despite the paucity of funds, due to under recovery of costs etc. Ikeja Electric focused on CAPEX required to improve the network, as indicated in table 1a above.

In December 2020, under the PIP the Federal Government of Nigeria, through the Central Bank of Nigeria's intervention, approved the Nigerian Electricity Market Stabilization Facility (NEMSF) Capex loan. The Capex allocation approved by NERC was N19.51bn, although CBN approved the funding of N18.84bn. It is therefore worth noting that the disbursement of the Capex loan, which was supposed to be used for the implementation of these technical Projects necessary for energy growth to deliver improved efficiencies, has been grossly delayed (see Table 1c).

Table 2b: Sources of CAPEX fund

CAPEX Funding Sources for 2018 -2022	Government Invention Loans	Customers Advance under MAP	IE funded	Total
	=N='m	=N='m	=N='m	=N='m
NEMSF 2	4,963			
NMMP	6,351			
MAP		19,226		
IGR, Commercial loans, Vendor financing etc.			13,802	
	11,314	**19,226**	**13,802**	**44,343**

Table 3c: Status of CAPEX funding under the CBN Intervention Loan to March 2023

Purpose	Approved (N'bn)	Disbursed (N'bn)	Balance (N'bn)	% of Utilized	Remarks	Impact on IE
Capex Funding	18.84	7.08	11.76	38%	Amount disbursed for supply of equipment and others to Capex Projects vendors; Disbursed between Nov 2021 and Feb 2023	The funding delay has significantly impacted the projects' costs, timelines and funding for loan repayment.

It is now pertinent to state that with the current IE infrastructure, along with the TCN restrictions being experienced and the slow funding interventions towards the proposed project for network strengthening and optimization to support this ambitious capacity growth trajectory in the MYTO model, IE's ability to deliver on its plan for energy increment may be adversely affected.

In Table 2 below, the current year's (2023) CAPEX funding projection in the PIP was about 22.044 billion naira plus the cumulative gap of 40.710 billion naira now carried forward from the previous years. Now the capex funding requirement is a total of 62.75 billion naira as at the year 2023.

Table 4: 2020 - 2023 Capex extract of IE PIP:

Description	2020 (Jan - Dec) (N'm)	2021 (Jan - Dec) (N'm)	2022 (Jan - Dec) (N'm)	2023 (Jan - Dec) (N'm)
PIP Projected	6,659	46,135	16,932	22,044
Capex Gap- Prior Year	-	-	38,393	40,710
Total Capex needed	6,659	46,135	55,325	**62,754**
Actual Utilized	(12,635)	(7,742)	(14,615)	-
Current Year Gap	-	38,393	40,710	
Capex Gap- C/f	-	**38,393**	**40,710**	**62,754**

Table 5a: Capex Funding Assumptions with Government intervention funds

2023 CAPEX Funding Assumptions		
Source of Funding:	=N=Million	=N=Million
CBN Funding carryover from 2022	20,170	
CBN Funding 2023 PIP Project	11,200	

DISREP	7,777	
SIEMENS Project	6,349	
Government Intervention-		45,496
Internal generated revenue	1,577	
Vendor Financing/Commercial Loans	7,598	
Asset Metering under MAP	8,083	
Internal Funding-		17,258
Total Source of Fund		62,754

Funding for capital requirements is essential to enable the company to meet the projected energy levels. However, due to the non-release of funds in 2021 and 2022 and considering that the loans have matured and are currently being paid, the business is unable to finance projects internally, given the consistent negative cash flow in prior years.

Ikeja Electric plans to fund **3%** of its CAPEX requirement through funds generated from the business, by reinvesting its return on capital earned from tariffs (Equity contribution), if the tariffs are reset and full cost reflective. We also intend to source **93%** through debt financing through CBN, vendor financing and commercial banks, at an expected interest rate between **9% - 25%** per annum and 10-year tenure, bringing average cost of capital to about **12% per annum.**

We also appeal for the support of the regulator in facilitating a special intervention where Discos can access the source of CAPEX funding at single digit cost of funds, DISREP if it comes through will be helpful in bridging the funding gap by 12%, while Siemens projects fund intervention would bridge the funding gap by another 10%.

Table 3b: Capex Funding Assumptions without Government intervention funds

2023 CAPEX Funding Assumptions		
Source of Funding:	=N=Million	=N=Million
Internal generated revenue	1,577	
Vendor Financing	5,466	
Commercial Loans	6,681	
Asset Metering under MAP	8,083	
Internal Funding-		21,808
Total Source of Fund		21,808

If there is no Government intervention funds, Ikeja Electric would, therefore, rely solely on its internal funds generated from the business by reinvesting its return on capital earned from tariffs (i.e., if the tariffs are reset and full cost reflective) and through commercial and vendor financing to fund its CAPEX requirement.

However, it is important to note that the funding would likely be uncontrollably restricted to about **35% CAPEX PERFORMANCE** (i.e., 21.8 billion naira) of the business's CAPEX requirement of 62.7 billion naira for the year 2023, due to the high rate of commercial lending, leveraged balance sheet and shorter repayment tenors. The expected interest rate of commercial financing is between **25% to 29%** with an allowable maximum of a 4-year tenor. In addition, sourcing fund largely from vendors and commercial loans has some level of associated risks as they come with potential drawbacks and challenges as interest rates may be reviewed upward from time to time.

The high-interest rates to the business would lead to an increase in the interest expenses and may lead to the business experiencing financial strain, making it challenging to meet repayment obligations or invest in essential projects, resulting in a substantial debt burden for the business.

It is, therefore, important to state that solely funding CAPEX through internal funding, commercial loans and vendor financing could limit the business's CAPEX requirement by 65% and might adversely affect the projected energy growth trajectory if funding is not available, if sourced at a higher cost it will impact the customer tariff as interest cost will be factored into the tariff to ensure repayment of interest and principal.

2.1. Summary of Historical Energy Levels

As explained above, there has been low funding to achieve the various technical projects of the Disco listed in the PIP document to achieve the proposed and projected energy increment level by the commission in the MYTO model in the past.

The table below buttresses the deficit on energy projection year on year.

Table 6(a) : Actual Energy received Vs MYTO projected Energy 2019 – 2022:

Description	2019	2020	2021	2022	2023
Delivered to IE (GWh)- (MYTO)	4,432	5,257	6,007	5,684	5,077
% Share (MYTO)	15.0%	15.0%	15.0%	15.0%	14.0%
IE Actual received (GWh)	4,265	4,633	4,541	4,082	4,767
% Actual Energy Rec'd to	96%	88%	76%	72%	94%

MYTO Energy					

One of the major challenges faced is chronic energy shortages on 33kv lines. This is either due to power generation shortages and/or limited capacity to load feeders due to paucity of equipment such as power transformers. The implication is that only some of our feeders are energized while others are subject to various forms of load shedding. Consequently, the underlying total load is difficult to achieve.

To boost energy supply, compliment grid and provide uninterrupted services to some identified clusters we have partnering with off-grid energy providers, with the plan to expand the off-grid and embedded generation partnership within our network, below table shows status and timelines of ongoing off-grid partnerships:

Table 4(b)7: Off-grid Energy Partners

OFF GRID SOLUTION								
S/N	Off-Grid Developer	PARTIES INVOLVED	Proposed Solution	Proposed Feeder	Site selected	Capacity (MW)	Current status	Estimated Timeline
1	Darway Coast (Isolated)	1.Sahara power group 2.Ikeja Electric. 3.Developer	Solar and Gas	11-Ope IluINJ-T1-Ijoko	Ibaragun	0.9	Project implementation phase	6 Months
2	Darway Coast (Interconnected Mini-grid)	1.Sahara power group 2.Ikeja Electric. 3.Developer	Solar and Gas	11-Ope IluINJ-T1-Ijoko	Robiyan	0.9	Project implementation phase	12 Months
3	Enaro	1. Ikeja Electric. 2. Developer	Embedded (Grid and Gas)	Ayobo and Fadayomi 11kV feeder	Ayobo	1	Project implementation phase	6 Months
4	A4T	1.Ikeja Electric. 2.Developer	Embedded (Solar, Grid and Gas)	33-IkoroduTCN-AGBOWA	Epe	0.8	Project implementation phase	12 Months
5	Gowus	1.Ikeja Electric. 2.Developer	Embedded (Grid and Gas)	33-Oke-AroTCN-AKUTE	Arepo	6	Power purchase review and negotiation stage	12 Months
6	ASB Valiant	1.Ikeja Electric. 2. Developer	Gas Generation	PTC Express 33kV	Oba Akran	8	Pre-feasibility Studies – commercial indicative estimates awaiting detailed design	12 Months
7	Makun\ASB Valiant	1.Ikeja Electric. 2. Developer	Gas Generation	33-Oke-AroTCN-AKUTE	Arepo	8	Pre-feasibility Studies – commercial indicative estimates awaiting detailed design	12 Months
					Total	25.6		

2.2. Projected Energy Levels

Table 5 below presents our proposed energy level for the year 2023, based on trend analysis of prior and current year energy levels. If adequate funding is available, we also project the incremental energy level for the next five (5) years over the baseline, defining this baseline then allows for future demand projections of unconstrained demand.

To forecast the demand for IE, a population projection analysis was carried out to determine the customer growth trajectory over the next 5 years. This projection is based on the average feeder population growth per tariff class. These potential customers per tariff class are applied to both 11kV and 33kV feeders over the 5-year forecast resulting in customer growth from 1.0 million in 2018 to 1.4 million in 2024, representing an increase of 40% in customer size from 2019 to 2023 and 64% increase in energy delivered from 2023 to 2028 as shown below. It is therefore important that the energy level be realistically set based on the current trend of the Gencos, TCN and infrastructure gap on the network.

Table 8: IE Energy projection 2023-2028: Proposed Energy Reset

Description		2023	2024	2025	2026	2027	2028
Projected B.A.U energy without projects (GWh)	A	4,638	5,399	5,959	6,511	7,105	7,653
incremental YoY energy from projects (GWh)	B	129	174	166	120	120	81
Total Projected Energy	C = (A + B)	**4,767**	**5,573**	**6,125**	**6,631**	**7,225**	**7,734**

2.3. Summary of Load during last Stress Test

Latest tress test was conducted by TCN for 3 days on the 30th March 2023 to 1st April 2023. Below were the key summaries:

- Day 1- with a minimum load of 466.7MW about 20no 33kv feeders were down due to TCN (Egbin TS was completely lost) and @ max load of 731.9MW, 4no 33kv feeders were down due to IE downtime (Maryland Alausa, Ajegunle etc).

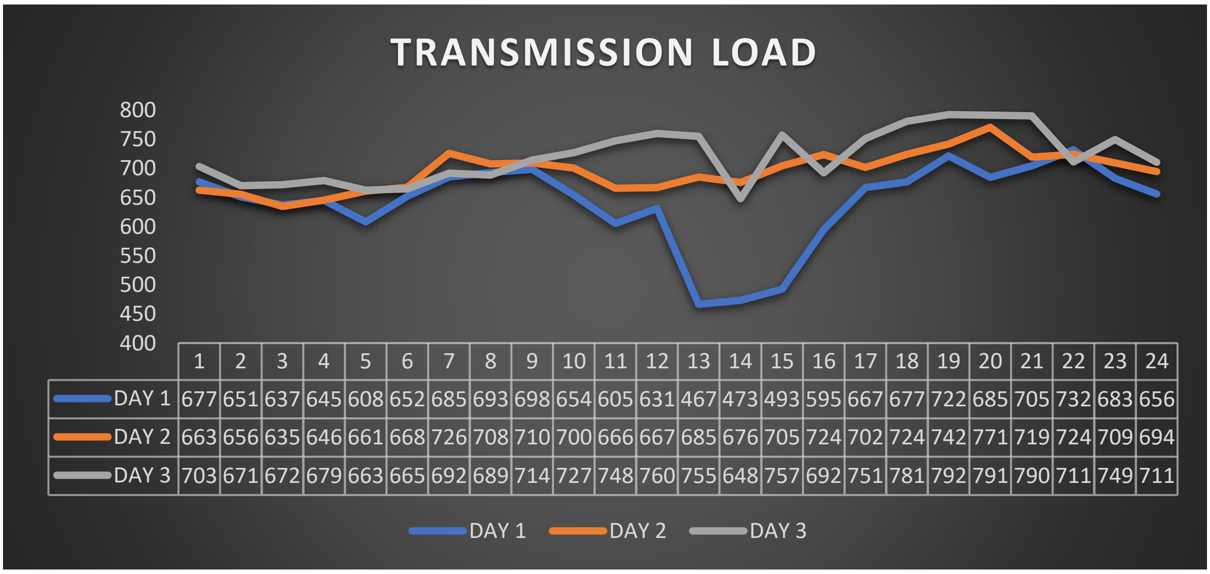
- Day 2 - with a minimum load of 634.6MW about 4 feeders were down due to IE downtime, @max load of 770.5MW, 2no 33kv feeders were down due to TCN downtime.

- Day 3 - with a minimum load of 647.9MW about 9no 33kv feeders & 1no for IE downtime respectively while 3no 33kvfeeders were down due to TCN, @max load of 792.3MW.

Table 9a: IE Energy Stress Test Performance

	DAY 1 THURSDAY 30-03-23	DAY 2 FRIIDAY 30-03-23	DAY 3 SATURDAY 01-04-23
MINIMUM LOAD (MW)	466.7	634.6	647.9
AVERAGE LOAD (MW)	641.3	694.9	721.3
MAX LOAD (MW)	731.9	770.5	792.3

IE Energy Stress Test Performance



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DAY 1	677	651	637	645	608	652	685	693	698	654	605	631	467	473	493	595	667	677	722	685	705	732	683	656
DAY 2	663	656	635	646	661	668	726	708	710	700	666	667	685	676	705	724	702	724	742	771	719	724	709	694
DAY 3	703	671	672	679	663	665	692	689	714	727	748	760	755	648	757	692	751	781	792	791	790	711	749	711

The above results were possible due of guaranteed supply as other Discos supply were reduced to accommodate the maximum energy request for Ikeja Electric's stress test.

Also, the Energy levels were at the maximum capacity of the Network which can only be achieved intermittently, due to the current condition of the network which cannot sustain the energy continuously without interruptions as demonstrated below:

Summary of the Distribution Downtime during the Stress Test were:

- 85% of Ikeja Electric feeders met Service Band Availability
- 37 feeders out of 281 feeders did not meet Service Band Availability due to service downtime.
- Analysis of 37 feeders that did not meet Service Band Availability:
  - 21 feeders were due to Network Limitations. Transformer limitation majorly in Sabo, New Alausa and Alimosho Transmission Stations.
  - 9 feeders were due to 33KV faults majorly in Epe, Maryland, Ajegunle, Igando, Ojodu and Abule Taylor.
  - 6 feeders were due to 11KV faults in Shomolu and Ikeja.
  - 1 feeder due to Substation fault in Isheri Oshun 11kv feeder.

The outcome of the stress test further buttresses the need for network strengthen projects within Ikeja Electric as indicted in the CAPEX Plan which only be supported by a cost reflective tariff that guarantees recovery of investments.

2.4. Ikeja Electric's Capital Expenditure (CAPEX) Required to Deliver Energy Projections

Our CAPEX projections were divided into eight periods to align with tariff design requirement and the current realities of cashflows. In the periods (2020-2022), the total investment requirements of the gold and silver clusters are, N24bn (40%) and N30bn (50%), respectively, due to the significant network upgrade and reinforcement needed in both clusters to guarantee reliable service delivery and reduce network losses. The other three clusters constitute N5.7bn (10%) of the investment planned over the same period. Due to the current business operating risk, as a result of tariff under recovery, delayed disbursement of CBN intervention funds, higher commercial interest rates, the business was unable to deliver the projects as planned.

The capital projects projections of the company are currently being largely funded with loans from CBN. The expected CBN Capex funding for 2021 (N19.5b) was not fully disbursed. Therefore, only some of the proposed projects were executed in 2021, resulting in a balance of N17.85b carried forward. In 2022, a Capex of N24.4b was expected to be funded by the CBN, but only N3.0b was provided, creating a deficit of N21.4b. As a result, achieving an ATC&C projection of 11.4% in 2022 became unattainable. The total deficit from 2021 and 2022 amounts to N39.2b, which was intended to be utilized for funding the 2023 projects. Please refer to table 5(c)below for more details.

The business was also funded with loans provided by other sources. These loans included short-term bail-out funds provided by the investors to support critical Capex and Opex obligations that the Company was unable to meet within specified timelines.

The capital projects aimed at achieving sustainable and progressive growth of the company are as follows:

Table 5(c): CBN Funded Five-Year Capex Projection:

Description	2023	2024	2025	2026	2027
	N'Bn	N'Bn	N'Bn	N'Bn	N'Bn
Proposed Capital Requirements	11.71	24.67	24.79	23.94	23.64
2021 & 2022 CBN Unutilized amount: (N39.2 billion)	15	10	10	4.2	0
Total Capex Required	26.71	34.67	34.79	28.14	23.64

2.4.1. Critical 5-year project listings:

Table 10: Five-Year Technical Capex Projection listing:

PERIOD	Summary of Network Investments
Jan – Dec 2023	1. Relief of overloaded DTs 2. Uprating of ISS in Ikeja BU 3. Injection substation for Oshodi and Ikorodu BU 4. Replacement of obsolete panels and Switchgear 5. Feeder rehabilitation for feeders already planned for Focused Feeder Maintenance 6. LT Rehabilitation across all BUs 7. Feeder radiation for 33k feeders in Shomolu and Ikeja BUs 8. Installation of FPI on high priority feeders 9. Upgrade of Injection substation projection
Jan – Dec 2024	10. Relief of overloaded DTs 11. Injection substation for Ikorodu, Shomolu, Akowonjo and Abule Egba BUs 12. Replacement of obsolete panels and Switchgear 13. Feeder rehabilitation for feeders already planned for Focused Feeder Maintenance 14. LT Rehabilitation across all BUs

	15. Feeder radiation for 33kV and 11kV feeders for new injection substations 16. Phased Deployment of SCADA infrastructure 17. Installation of FPI on high priority feeders 18. Replacement of aged power transformers 19. Upgrade of substation projection
Jan – Dec 2025	20. Relief of overloaded DTs 21. Injection substation for Oshodi, Abule Egba, Shomolu, Akowonjo and Ikorodu BUs 22. Replacement of obsolete panels and Switchgear 23. Feeder rehabilitation for feeders already planned for Focused Feeder Maintenance 24. LT Rehabilitation across all BUs 25. Phased Deployment of SCADA infrastructure 26. Feeder radiation for 33kV and 11kV feeders for new injection substations 27. Installation of FPI on high priority feeders 28. Replacement of aged power transformers 29. Upgrade of substation projection
Jan – Dec 2026	30. Relief of overloaded DTs 31. Injection substation for Oshodi, Shomolu, Akowonjo and Ikorodu BUs 32. Replacement of obsolete panels and Switchgear 33. Feeder rehabilitation for feeders already planned for Focused Feeder Maintenance 34. Phased Deployment of SCADA infrastructure 35. LT Rehabilitation across all BUs 36. Feeder radiation for 33kV and 11kV feeders for new injection substations 37. Installation of FPI on high priority feeders 38. Replacement of aged power transformers 39. Upgrade of substation projection
Jan – Dec 2027	40. Relief of overloaded DTs 41. Injection substation for Oshodi, Abule Egba, and Ikorodu BUs 42. Replacement of obsolete panels and Switchgear 43. Feeder rehabilitation for feeders already planned for Focused Feeder Maintenance 44. LT Rehabilitation across all BUs 45. Feeder radiation for 33kV and 11kV feeders for new injection substations 46. Phased Deployment of SCADA infrastructure 47. Installation of FPI on high priority feeders 48. Replacement of aged power transformers 49. Upgrade of substation projection
Jan – Dec 2028	50. Relief of overloaded DTs 51. Injection substation for Akowonjo BU 52. Replacement of obsolete panels and Switchgear 53. Feeder rehabilitation for feeders already planned for Focused Feeder Maintenance 54. LT Rehabilitation across all BUs

	55. Feeder radiation for 33kV and 11kV feeders for new injection substations 56. Phased Deployment of SCADA infrastructure 57. Installation of FPI on high priority feeders 58. Replacement of aged power transformers 59. Upgrade of substation projection 60. Network Metering Investments

Below is the specific metering CAPEX projection for 2023 and further breakdown listing for 2024 and 2025.

Table 7(a): 2023 Metering Capex Projection:

Metering Capex	2023	
Description	Units	Amount N'Bn
Non-MD Meters:		
Meter Asset Fund	110,000	8.10
MAP	170,000	12.62
Debt for Metering/Vendor Financing	50,000	3.67
MD Meters:		
HV/LV Meters	1,300	0.39
Primary side	910	3.16
Distribution Transformer Meters (New/Relief):	2,450	1.25
MDA Prepaid Meters:	114	0.97
Total Metering Cost		30.16

Table 7(b): 5 Years Metering Capex Projection all Categories of customers:

Description	2023 N 'million	2024 N 'million	2025 N 'million	2026 N 'million	2027 N 'million	Grand Total N 'million
Metering of NMD unmetered Customers via MAPs	12,624	13,367	11,882	8,815	8,169	54,856
Unit Cost	74,260	74,260	100,096	80,135	11,058	339,809
Qty	170,000	180,000	118,702	110,000	738,702	1,317,404
Primary side Metering and MDA Metering Requirements	1,288	1,285	1,282	-	-	3,855
Unit Cost	2,002,977	2,007,986	2,002,977	-	-	6,013,939
Qty	643	640	640	-	-	1,923
Deployment of Bulk Metering Solutions	13,629	3,269	2,037	-	-	18,934
Unit Cost	9,700,000	9,700,000	9,700,000	-	-	29,100,000
Qty	1,405	337	210	-	-	1,952
IDB Deployment	13,155	13,929	12,382	9,186	8,512	57,164
Grand Total	40,696	31,850	27,582	18,001	16,681	134,810

2.4.2. CAPEX Loan Repayment Impact on Cashflow

The current loans sourced from CBN offered a moratorium of 2 years on principal repayment. However, we are also advocating for addition 2 years as it would help stabilize operations and reduce the current cash deficit as the delayed in funds disbursement did not allow us take benefit of the moratorium period to complete the projects as a result, project remains uncompleted as moratorium ends, therefore projects unable to pay back funds. Resulting in additional strain on the business. By deferring the repayments, the Company can utilize those funds to offset some of its outstanding obligations and fund some of the projects listed above.

The table below shows the annual repayment amount to CBN on CAPEX loan disbursed so far and projections for full disbursement in 2023.

Table 7: CBN Loan Repayment and Funding of New loans

CBN Loan Repayment	2021 N'Bn	2022 N'Bn	2023 N'Bn	2024 N'Bn	2025 N'Bn	2026 N'Bn	2027 N'Bn	2028 N'Bn
Existing Loans:								
Principal payable	2.29	1.47	8.10	6.26	5.10	5.41	5.91	6.47
Interest Payable	1.66	3.14	4.50	3.71	3.16	2.71	2.20	1.64
New Loans:								
Principal payable	-	-	-	-	3.93	7.21	9.93	12.10
Interest Payable	-	-	3.54	6.84	9.94	12.43	14.47	16.15
Total	3.95	4.61	16.14	16.81	22.13	27.75	32.52	36.36

Table 8: If 2 years moratorium request is allowed- CBN repayment of loans on both Principal and Interest:

CBN Loan Repayment	2023 N'Bn	2024 N'Bn	2025 N'Bn	2026 N'Bn	2027 N'Bn	2028 N'Bn	2029 N'Bn	2030 N'Bn
Existing Loans:								
Principal payable			8.1	6.26	5.1	5.41	5.91	6.47
Interest Payable			4.5	3.71	3.16	2.71	2.2	1.64
New Loans:								
Principal payable			-	-	3.93	7.21	9.93	12.1
Interest Payable			3.54	6.84	9.94	12.43	14.47	16.15
Total	-	-	16.14	16.81	22.13	27.75	**32.52**	**36.36**

Therefore, we kindly request that CBN provide the necessary finance to fund the Capex projects and allow for an extended moratorium period on the existing loans, aligning it with the project delivery period. This will enable the Company to fully benefit from the moratorium and ensure that the projects have a significant impact on the operations and efficiency of the business in the sector.

2.5. TCN's Capital Expenditure Required to Deliver IE's Energy Projections

For IE to meet its energy projections, it is imperative TCN prioritizes investments in the following transmission stations due to the (difference) between station peak demand and station capacity by 2027, Ejigbo (62MW), Egbin (53MW), Ikorodu (45MW), Maryland (40MW), Itire (26MW), and

Alausa (25MW). Across the substations, Ikorodu substation has the current highest peak demand of 210MW and is expected to increase to 235MW by 2027. While Ikorodu station has a transformation capacity of 280MVA, its actual operational capacity of 190MW is constrained to serve IE's demand. The largest percentage increase in demand over the period occurs at the Ejigbo station, with a 45% increase from 170MW to 215MW.

Across the 17 TCN stations that supply IE's franchise area, in 2021, there was sufficient capacity to meet the peak demand in only 6 stations (Alimosho, Ayobo, Amuwo, Ogba, Oworo and Odogunyan). TCN stations with sufficient capacity to meet IE peak demand are expected to reduce 2 stations (Odogunyan and Alimosho) by 2027, if significant expansion projects are not done.

As part of the PIP process, below are the summary of the required interventions from TCN:

Table 9(a): Summary of required interventions from TCN

	TCN Station	Constraints	Action Required	Status
1.	Akoka	Completion of the conversion of indoor 33kV breakers to outdoor	The completion of this project will enable us to supply the idle 15MVA transformer at 68th military. This will enable us to radiate 3 more feeders to help customers enjoy more supply around Jibowu and its environs.	The 33kV feeder to feed 68military ISS from Akoka station will require construction of new bay by TCN
2.	Maryland	Capacity Constrained	-Replace the CT on Maryland Alausa feeder to 400/1A 2. -Upgrade the 2X30MVA to 2X 60MVA	-IE to notify Market Operator of the Current Transformer replacement. -Project Ongoing
3.	Alausa	Significant Capacity Constrained	- Convert the indoor arrangement of the 45MVA transformer to outdoor to avoid the kind of issues we are currently experiencing in Oworo. - Uprating the power transformers to 100MVA. -Completion of proposed 132kV line via Oke Aro.	- Depends on uprating to 100MVA -Ongoing - TCN confirms that NIPP will handle this construction
4.	Itire	Capacity Limitation	Upgrading of T1 30MVA to 60MVA transformer	-Ongoing
5.	Oworo	Capacity Limitation on T2 60MVA	-Upgrade the 2X30MVA to 2X 60MVA	30MVA to be replaced by 1x60MVA.

6.	Oke Aro	Capacity Constrained	-Uprating of the 2X60MVA to 2X 100MVA to allow us to supply our feeder. - IE proposed Transmission Station for the Kara/Berger, to take care of Lagos - Ibadan Expressway axis (We need about 40MW)	-TCN plans to upgrade capacity with an additional 1x60MVA -TCN confirmed construction work is currently ongoing on two new stations, at MFM (330/132/33KV TS) and RCCG (132/33KV TS). IE survey reveals work has not commenced.
7	Amuwo	Capacity Constrained	Upgrading of 2X30MVA to 2X60MVA transformer to accommodate more load.	TCN says this is already captured by NETAP for upgrade.
8.	Isolo	Capacity Constrained	Upgrading of T3 45MVA transformer to accommodate proposed ISS	TCN plans to move-in a Mobitra transformer for upgrade.

The Presidential Power Initiative (PPI) and the CBN, African Development Bank programme targeted at the Disco side interface with TCN, a network infrastructure investment program via Siemens, are also potential source of CAPEX funding for TCN projects.

2.6. Analysis of the load allocation across service bands and across voltage levels

With the network improvement plans and scheduled projects, it is expected that service level to customers will improve, frequency of interruption will reduce, and customers will have a better experience, we have planned year on year migration of customers to higher feeder band for better availability and service which will also help reduce the Weighted Average Tariff eventually.

With 85% of our customers within band A and C and 15% in band D and E in 2023. By 2025 we plan to improve this to by ensuring all our customers are within band A and C, eliminating band D and E within our network.

By 2028, we plan that all our customers would have been moved to band A and B, eliminating band C to E, these plans must be supported by the CAPEX projects plan identified in table 6 (I.E's projects) and Table 9 (TCN's interface projects).

Table 9(b): Service Band Migration Plan

Category	2022	2023	2024	2025	2026	2027	2028
Life-line	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
A - Non MD - Platinum	5.6%	13.8%	13.8%	17.3%	22.3%	24.3%	24.9%
A - MD1 - Platinum	5.5%	0.2%	0.2%	1.0%	1.0%	1.0%	1.0%
A - MD2 - Platinum	10.0%	15.5%	15.5%	15.9%	15.9%	20.9%	20.9%
A - Bilateral	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
B - Non MD - Diamond	10.8%	14.6%	14.6%	17.5%	22.5%	27.5%	36.3%
B - MD1 - Diamond	4.0%	0.9%	0.9%	4.7%	4.7%	5.7%	6.1%
B - MD2 - Diamond	1.2%	4.4%	4.4%	5.3%	5.3%	5.3%	5.9%
C - Non MD - Gold	32.0%	26.4%	26.4%	28.8%	18.8%	8.8%	0.0%
C - MD1 - Gold	2.6%	1.4%	1.4%	2.0%	2.0%	1.0%	0.0%
C - MD2 - Gold	3.7%	2.6%	2.6%	2.6%	2.6%	0.6%	0.0%
D - Non MD - Silver	18.1%	13.5%	13.5%	0.0%	0.0%	0.0%	0.0%
D - MD1 - Silver	0.8%	0.5%	0.5%	0.0%	0.0%	0.0%	0.0%
D - MD2 - Silver	0.2%	0.7%	0.7%	0.0%	0.0%	0.0%	0.0%
E - Non MD - Bronze	0.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
E - MD1 - Bronze	0.1%	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%
E - MD2 - Bronze	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.00%**	**100.00%**

- Analysis of Recent SAIFI, SAIDI and CAIFI resulting from transmission and distribution limitations.

Table 9(c): January – May 2023 SAIFI, SAIDI and CAIFI

2023	CUSTOMER HOURS	CUSTOMERS INTERRUPTED	INTERUPTION DURATION	INTERUPTION FREQUENCY	TOTAL NUMBER OF CUSTOMERS	SAIDI (minutes)	CAIDI (minutes)	SAIFI	CAIFI
Jan	15,545,996	1,061,443	2,360,230	25,478	1,178,692	791	879	0.90	0.02
Feb	12,116,882	1,059,044	1,878,202	22,927	1,180,804	616	686	0.90	0.02
Mar	11,980,472	1,059,050	1,811,570	20,396	1,188,391	605	679	0.89	0.02
Apr	14,524,194	1,058,884	2,202,618	28,929	1,192,197	731	823	0.89	0.03
May	12,805,495	1,059,460	2,013,586	23,480	1,205,773	637	725	0.88	0.02

3. ATC&C Projections

Since taking over, we have made significant investments in improving our systems and infrastructure, with the aim of enhancing service delivery and achieving our target baseline for ATC&C (Aggregate technical, commercial, and collection) losses. A substantial amount of investment, including financial resources and human capital development, has been dedicated to acquiring cutting-edge information technology (IT) infrastructure. These investments have enabled us to implement automated systems that minimize human errors and significantly reduce losses. As a result, we have witnessed a substantial improvement in the reduction of our technical, collection, and commercial losses. In 2014, our baseline loss study submitted to NERC reported a loss of 41.3%, but by the end of 2022, we had achieved a reduction to 19.6% with an all-time low energy level, however with energy levels on the rise in 2023, we have seen ATC&C losses going back to 23%.

The allowable loss threshold is about 11.37% in MYTO tariff model is not attainable, despite all strategies and resources deployed, at today the losses are at 23% giving a variance of about 12% above the allowable. It has also been established that as energy levels increase ATC&C also moves in similarly.

Please see below the contributory factors of to our ATC&C losses:

- Energy theft from prepaid metered customers
- Poor energy accounting through obsolete and compromised meters.
- Nonpayment from postpaid/estimated customers/MDA customers
- Poor MD customer Metering Infrastructure
- Energy Theft from customers on Private DT (MD/MDA)
- Unbilled Energy from NMD customers dominated DT's.
- Unmetered Load points
- Metering inaccuracy
- Faulty metering instruments such as VTs and CTs

It is worth stating that the ATC&C loss targets used in the calculation of Ikeja Electric's tariff do not consider the above factors and some critical resources listed below:

- the current state of infrastructure, technology and financial resources available to the business, therefore making the target unrealistic and unattainable.
- Insufficient allowable Operational Expenditure (OPEX) in the tariff model, this has led to lack of liquidity to support specialized loss reduction strategies, vendor financing for metering, franchising arrangements, deployment of smart check meters and other infrastructural and technological enhancements designed to mitigate specific losses.

3.1. Our Loss Reduction Methodology

Our loss Reduction Strategies is centered around customer and cluster categorization. These clusters have been categorized in line with the peculiarity of the location, accessibility, capacity of customers to consume and willingness of the customers to make payment. To this effect the loss reduction strategies are centered around losses arising from categories of customers, DT (Distribution Transformers) and cluster. This categorization has become necessary to ensure that the loss reduction strategies address the real causes of the losses and achieve the expected impact.

Table 10(a): Distribution Transformer / Customer Categorization

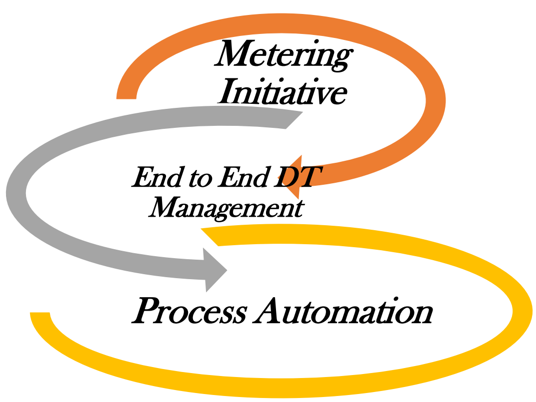
Customer Category	Cluster Category	DT Category
NMD Customers	Restive Clusters	HVDS, MD on Public and Regular DT (Ground mounted)
	Non- Restive Clusters	HVDS, MD on Public and Regular DT (Ground mounted)
	Multi-Tenanted Cluster	HVDS, MD on Public and Regular DT (Ground mounted)
MD Customers	Private DT	DT with only one customer
	MDA DT	MDA DT (Government parastatals)
	Hybrid DT	Private DT with more than one MD customer

3.2. Loss Reduction Strategies

These loss reduction strategies and initiatives are tailored towards the causative factors, cluster requirement and DT category above. Ikeja electric focuses on reducing losses through Metering Initiative, Process automation and DT management Focus.

- *Metering Initiative:* Our existing strategies which include but are not limited to MD PPM, IDB and primary side metering initiatives to address loss reduction from MDA, NMD and MD customers respectively. While we haven't rolled this out massively due to funding, we have implemented the initiative for new metering needs as required just in time.
- *DT Management:* This strategy focuses on driving core operational activities from the DT level including performance.

- *Process automation:* We focus on full automation of commercial processes as well as deploying systems and structures to ensure that the loss reduction processes deployed are sustainable. This will also improve operational efficiency, reduce high manual dependency and reduce overall cost of operations in the long run.



3.2.1. Metering Initiatives

We have identified various initiatives to close our existing metering gap and replacement of obsolete meters within our network to ensure proper energy accounting, please see table 10(b) for breakdown.

Table 10(b): Analysis of current Metering Gap

Total Active Customers
1,094,011

Total Unmeterred Active Customers
263,719

Total Unmeterred Active MD Customers
5,421

Total Unmeterred Active NMD Customers
258,298

Total Active Customers with Obsolete Meters
143,058

Current metering gap from the above diagram shows total of **406,778** customers without meters or with obsolete meters, representing **37.2%** of our active customers. In order to close these gaps and reduce losses, below are some of our planned initiatives:

a) Primary Side Metering

This metering design is to eradicate the slightest ounce of energy theft from Private transformers in the network by installing the customer's meter on the primary side of the private distribution transformer in order to record every energy that goes to the customers thus reducing losses to barest minimum. It is used on customers with a distribution transformer capacity of 200kVA and above. All points load customers in this category of distribution capacity category must be metered at the primary side to reduce the losses accrued due to the transformer core losses establish during the No Load operational period of the transformers.

b) Installation Of Interface Meters on Long Span Feeders

This strategy is deplored on feeders with very long route length in the network. The design approach is deplored in order to sectionalize the feeder to easily identify the root cause of the high losses across the line. This strategy has been deployed previously on Maryland Ajegunle 33kV feeder and it yielded a positive outcome. There are plans to install this interface meters on other 33kV feeders such as Agbowa, Ijede etc.

c) Intelligent Data Box Metering of Unmetered NMD Customers Vendor Financing Scheme, Mass Metering under NNMP 1, Meter Asset Fund.

IE can monitor energy supply based on SBT Feeder bands. However, IE does not have control over the supply on 33kv feeders and as such unmetered customers on these feeders will typically contribute to high losses due to impact of capping for postpaid customers leading to unbilled energy and the fact that customers may have also taken up energy that they do not have ability to pay for after being billed using the capping methodology.

Mass metering strategy was deployed using NMMP phase-0 metering initiative. However, with the delay in NMMP phase-1 metering deployment, we have resorted to vendor finance option and MAPS to reduce the losses from these customers, however not as effective as the mass metering.

The Intelligent Data box design approach will be used to independently determine the consumption of a customer or household, irrespective of the consumption recorded on the meters installed in the customer's premises. Hence this solution seeks to achieve the following:

- ❖ Reduce or eliminate energy theft in Ikeja Electric.
- ❖ To have full control and visibility of energy from entry point to the final consumer.
- ❖ To be able to independently verify or determine the actual energy/consumption of customers.
- ❖ To be able to remotely and independently cut-off supply once the energy consumed meets the energy vended that is registered on Intelligent Data Box.
- ❖ Helps in determining actual consumption of metered and unmetered customers.
- ❖ It will immediately identify and flag meters that lack integrity or have been compromised.

IDB reduction strategies planned have not been deployed due to funding limitations and Cost implications of IDB however Bulk Metering initiatives seeks to deploy cheaper AATC&C metering initiative as a short-term solution pending when the business is financially ready to deploy IDB.

Table 10(c): Analysis of IDB 5-year Budget

Initiative Budget	2023 N' Million	2024 N' Million	2025 N' Million	2026 N' Million	2027 N' Million	Grand Total N' Million
IDB Boxes and DCU Cost	5,581	5,909	5,253	3,897	3,611	24,251
IDB Network clean up	2,525	2,673	2,376	1,763	1,634	10,971,
IDB ABC deployment Cost	5,050	5,347	4,753	3,526	3,267	21,943
Total IDB Cost	13,156	13,929	12,382	9,186	8,512	57,165

d) Distribution Transformer Bulk Metering (applicable to MDA, MD and NMD)

Bulk Metering utilizes a design approach which ensures the energy accounting using an electronic meter at the distribution transformer source point as the primary reconciliation reference for energy consumed. The distribution transformer meter shall be installed at the Primary side of the transformer.

There are 3 main initiatives in design.

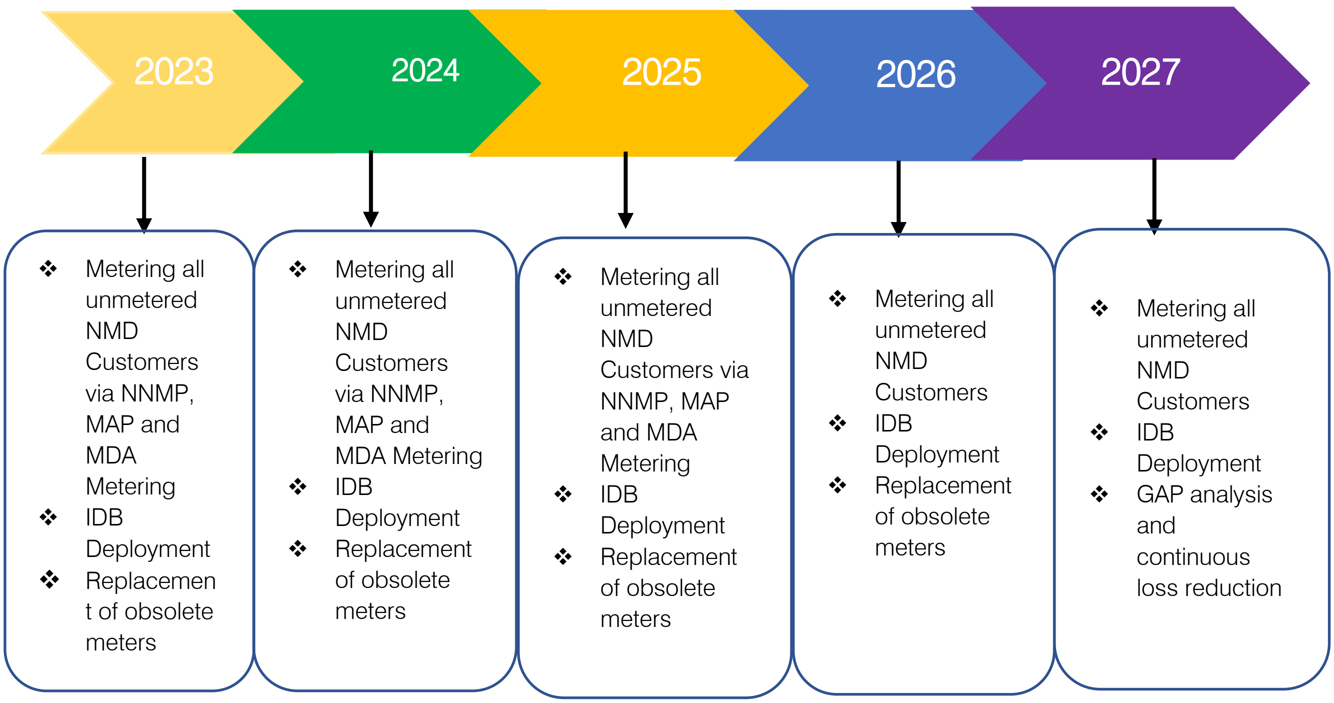
- MD PPM Code I: Here, the vending of customers connected to the DT appear directly as the vending on the DT PPM, and the energy on it is deducted based on the total energy usage of all customers connected to DT. For instance, if the energy of the DT meters finishes before the energy of customer meters, it is indicative of possible bypass or theft at the side of the customers.

- MD PPM Code O: This is like Code I only in that it will be managed by third parties who will be responsible for installing check meters for customers on such DTs. We will have access to the third-party vending database.

- MD PPD Code I or O: This design accommodates either of the 2 designs above but having a Postpaid DT Meter at the Primary-side of the distribution transformer.

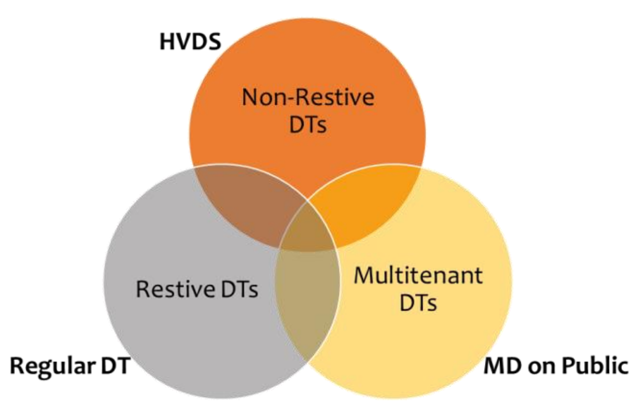
3.2.2. Implementation Plan and Prioritization

We have further prioritized our loss reduction in order of relative importance to ensure continuous improvement in losses hence we have identified and prioritized in phase categories and yearly plan.



3.2.3. DT Management

We have categorized our distribution transformers into various DT Types and Cluster in order to prioritize and optimize loss reduction in order of relative importance. Kindly see classification below



HVDS: This is also known as High Voltage Distribution System. These set of transformers have transformer capacity of 25, 50 and 100kVA. They have a small customer population ranging from 1-10, depending on the customer load.

MD on Public: This are maximum demand customers on Public Distribution Sub-station, This MD customers has different type of connection which includes but not limited to dedicated leg, LV Connection etc.

Regular DT: The regular DT are ground mounted DTs which are not HVDS and do not have MD customers on them.

The DT types were also categories based on Cluster types. These include.

- **Resistive DTs**: This are DT locations which possess a lot of push back and restricts the operational tasks for the various teams in those locations. They push back affects the customer billing, collection and affects other initiatives to be deployed in those locations.

- **Non-Restive DTs**: These are locations which do not restrict operational tasks of the team and further enable the team to carry out all initiatives deployed where applicable.

- **Multitenant DTs**: This includes blocks of flats, apartments and shops that are connected to a single transformer.

We also deployed the below DT management strategies to ensure loss reductions.

i. **Feeder & DT Manager Initiatives**

Point load dominated feeders with high variance are allocated to Maximum demand metering Engineers for monitoring and management to identify the root cause of losses if there be and proffer resolutions before the next billing calendar and this is about 50% of their KPI. We have seen huge improvement from this.

ii. **DT Driven KPI:**

This Strategy Focuses on Setting KPIs Based on DT Performance, the objective is to ensure that activities of the field staff are targeted at points that will have huge impact on loss factors and fundamental issues.

3.2.4. Energy Loss Reduction Study Exercise

Energy Loss reduction exercises is carried out monthly to identify feeders with high loss and to ensure the losses are reduced before the following month based on certain criteria such as revenue implication, consistency of the losses on the feeder over a period. This exercise is done by visiting all the assets on all 33kv & 11kv line starting from the transmission station which is source input.

After the exercise, a report was established which entails anomalies discovered, these anomalies were sent to the responsible parties for resolution.

Table 10(c): Types of Losses

Type of Losses	Forms	Details
Technical	Fixed Technical Losses	They are losses within the core of the transformers
	Variable Technical losses	Lengthy feeders
		Load Imbalance
		Inadequate sizing of conductors
		Inductive loads on the lines
		Overloading of lines
Commercial	Human type	DT to feeder alignment
		Poor Metering Infrastructure
		Energy Theft
		Unmetered Load points
	Non-Human type	Metering inaccuracy
		Faulty metering instruments such as VTs and CTs

3.2.5. Commercial Process Automation

There is a major Focus in full automation of commercial process as well as deploying systems and structures for loss reduction. The meter installation process has been automated, the metering order system also automated through Pre Archiving Platform. The After Metering Process is the next step and the automation of these processes will improve operational efficiency. Other commercial processes like account creation, MD operations automation, NIN identity authentication and self-service enquiry platform are in the plan for automation.

Digitalisation of Form 74

Self-Service Platform For loading Energy Token

Upgrade of MD and NMD Billing Process Platform

NIN KYC identity authentication

Pre Metering Process communication Automation

Meter Payment-Plan Wallet

After Meter Service process Automation

Deployment of ESR workforce app

LOR Process Billing Automation

3.2.6. Limitation to Strategies and Initiatives to Loss Reduction

1. Paucity of funds as a result of under recovery of OPEX, we are limited by funds available from the tariff to deploy and implement most of the strategies identified above, as our tariff currently has not considered the expenditure required to drive down losses. We currently recover only about 50% of our actual operation expenses from the current tariff as structured, therefore limiting the implementation of the above initiatives.

2. Delays in Government support initiatives: Government have in recent years under the PIP come up with laudable initiatives to help support the Disco with infrastructure to drive down losses, the impact of the success of the NNMP phrase 0 cannot be overemphasized, where our overall ATC&C losses reduced, we had hoped on the roll out of NNMP phrase 1 to consolidate the gains on phrase 0, however that has not happened. With delays from CBN on the PIP CAPEX funding has also undermined our ability to roll out some of the initiatives planned.

3. Restiveness in some environment, lack of support from some communities in rolling out initiatives to reduce losses, apathy to payment and entitlement expectations of free power also affects ability to improve losses in some locations.

3.3. Loss Components

The breakdown of the loss components of ATC&C will give better insight to the factors to be considered in resetting the loss target in the tariff structure:

- <u>Commercial Loss:</u>

It is evident that when a significant portion of customers are not metered, it becomes challenging to identify and address issues such as tampering, meter bypassing, or underreporting of consumption. These issues contribute to commercial losses and impede the financial performance of the Discos. The percentage of metering plays a crucial role in determining the extent of commercial losses. To improve our metering density, we had planned to fully utilize our allocation under the NNMP 1, building on the success we recorded under the NNMP) where we completed and even exceeded our meter installation within the stipulated time. The NNMP 1 would have helped in closing about 300,000 unmetered customer gaps, which would have significantly helped in reducing commercial losses.

However, to forestall the impact of the about, we intensified the MAP, installing monthly average of 10,000 meters since we recommenced the programme in 2022, we also took on 10,000 meters on a vendor refinancing arrangement as these has help improved our losses. However, it is still far from the target as it is difficult to accurately measure and bill customers' actual consumption. This situation has created opportunities for theft and unauthorized use of energy within our network over time.

Although reducing commercial losses due to energy theft is one of the challenges Ikeja Electric would continuously address over the next five years as stated in the submitted PIP plan, the absence and delay of the DISREP, NNMP 1 Loan and other planned funding interventions for various commercial projects and customer metering indicate that the trajectory of commercial losses will be difficult to control as energy grows.

Also, considering the impact of capping on unmetered customers, the proposed commercial loss target appears to be unrealistic (refer to table 11 below). A review of the billing for unmetered customers in our network for the year 2022 reveals a significant effect of capping on their bills. It was observed that approximately 410 GWh of the actual energy consumed by non-maximum demand (NMD) customers would have been affected due to the capping process being applied. Consequently, this would have resulted in an excessive increase in commercial losses for the business, as shown in the table below (Table 10d).

Table 10(d): Year 2022: Impact of Capping on Commercial losses

PERIOD	Total Billed KWH	Actual Billed KWH	Capping KWH	Impact on Cap KWH	Impact %
2022	3,624,829,786	988,993,696	578,574,788	(410,418,908)	11.32%

The cumulative impact of capping as of May for the year 2023 is approximately 231 GWh as seen below.

Table 11: Year 2023: Impact of Capping on Commercial losses:

PERIOD	Total Billed KWH	Actual Billed KWH	Capping KWH	Impact on Cap KWH	Impact %
Jan- May 2023	1,663,488,770	447,588,886	215,705,205	(231,883,681)	13.94%

Considering the number of our unmetered customers along with the impact of capping and the proposed IE energy level of 4767 GWh, this will further increase the commercial loss of the business, justifying the need for a realistic commercial loss target in the MYTO model.

- ❖ <u>Collection Loss:</u>

Currently, we have over 400,000 unmetered customers and customers with obsolete or faulty meters, resulting in an effective metering gap of approximately 40%. This metering gap poses a significant challenge in reducing our collection losses, as unmetered customers are less willing to pay bills based on the Estimated Billing Methodology. With the existing gap in customer meters, Ikeja Electric faces difficulties in collecting revenues from regularized unmetered customers, and illegal activities further worsen our cashflow situation. Unfortunately, due to the lack of funds through the DISREP and CBN intervention initiatives, we do not anticipate the implementation of our PIP, including customer metering projects. The non-execution of these projects will jeopardize IE's performance in reducing losses for the current year and the coming years, but we are hopefully that with Regulators intervention and set up of the Meter Asset Fund, if implemented may help improve metering and will help subsequent period loss reduction target. In addition, IE will face challenges in mitigating the economic changes that will also impact its collection performance, thereby hindering its ability to reduce collection losses to meet the MYTO target parameter. Some of the economic changes include an increase in the cost of living, which affects customer purchasing power which may lead to customer apathy to payment.

Table 12: Year 2023: Impact of Capping on Commercial losses:

Description	2019	2020	2021	2022	2023 Projection
Energy (GWh)	4,265	4,633	4,541	4,082	4,767
Metering Density	32%	47%	62%	66%	72%
ATC&C	24.93%	29.85%	23.32%	19.60%	19.60%
Technical & Commercial loss	12.10%	8.90%	10.70%	11.72%	7.40%
Collection Loss on Revenue billed	14.60%	23%	14.10%	9.90%	5.1%
% Growth/(Reduction)					

% Growth/(Reduction	*From 2019 to 2020*	*From 2020 to 2021*	*From 2021 to 2022*	Projection 2023
Energy (GWh)	8.63%	-1.99%	-10.11%	16.66%
Metering Density	46.88%	31.91%	6.45%	9.09%
ATC&C	19.74%	-21.88%	-15.95%	0.00%
Technical & Commercial loss	-26.45%	20.22%	9.53%	-36.86%
Collection Loss on Revenue billed	57.53%	-38.70%	-29.79%	-48.48%

From the table above, it has been demonstrated that losses have direct relationship with growth in energy considering the number of unmetered customers within the network that would be directly impacted by the effect of capping on energy once energy grows as demonstrated in table 10 above when capping accounted for 11% ATC&C loss (being the commercial loss for 2022).

Table 13: Commercial & Collection Loss – MYTO Vs IE Actual:

Loss Reduction	2021			2022		
	MYTO	Actual	Variance	MYTO	Actual	Variance
Commercial loss	9.4%	11.2%	-1.8%	8.3%	10.8%	-2.5%
Collection loss	0.03%	14.6%	-14.6%	0.03%	9.9%	-9.8%
ATC&C	**12.5%**	**24.2%**	**-11.7%**	**11.4%**	**19.6%**	**-8.2%**

Given the persistent disparity between our current ATC&C losses and the projected ATC&C losses in the MYTO, despite the resources deployed, meeting our total market obligations has continuously resulted in an inability to fully recover our costs, meet staff, statutory and operational obligations, these has posed challenges to our business operations and efficiency.

The difference between the actual ATC&C losses and allowed ATC&C in the tariff structure has consistently resulted in yearly erosion of shareholders' funds, making the business unattractive to new capital and investors, which has direct impact on the company's going concern and continuity status, despite all that have been put into the business.

In addition, a review of the MYTO projections on the ATC&C for the other major players within the value chain can be deduced that Ikeja Electric had the steepest ATC&C target amongst its peers considering the proposed level of energy and the targeted ATC&C allowable. This is irrespective of the fact that the counterparts with similar business conditions and realities have higher ATC&C target.

Ikeja Electric has consistently demonstrated the ability and willingness to reduce ATC&C (please refer to table 12) despite the limited resources. However, the target set is unrealistic and unattainable as stated.

Table 14: Ikeja Electric & other DISCOs – Energy Vs ATC&C:

DISCOs	Description	2023	2024	2025	2026	2027	2028
Abuja	Energy (GWh)	4,945	5,603	6,179	6,816	7,433	8,004
	ATC&C	19.3%	19.3%	15.9%	13.1%	13.1%	13.1%
Enugu	Energy (GWh)	3,484	3,947	4,353	4,801	5,237	5,639
	ATC&C	11.3%	11.3%	9.6%	8.2%	8.2%	8.2%
Ibadan	Energy (GWh)	4,491	5,088	5,612	6,189	6,750	7,269
	ATC&C	15.5%	15.5%	12.9%	10.8%	10.8%	10.8%
Eko	Energy (GWh)	4,320	4,894	5,398	5,954	6,493	6,992
	ATC&C	14.2%	14.2%	11.9%	10.0%	10.0%	10.0%
Ikeja- MYTO	Energy (GWh)	5,077	5,752	6,344	6,997	7,631	8,217
	ATC&C	11.4%	11.4%	9.7%	8.2%	8.2%	8.2%
Ikeja- Proposed	Energy (GWh)	4,767	5,573	6,125	6,631	7,225	7,734
	ATC&C	19.6%	18.9%	16.4%	14.8%	13.1%	11.4%

Therefore, we strongly urge the commission to review and acknowledge our loss reduction efforts and consider our realistic loss forecast from 2023 to 2028 in calculating the tariff, as shown in Table 15 below. We also request a cost recovery mechanism that incorporates the actual ATC&C losses of Ikeja Electric in the past years during the recalculation of our tariff shortfall, as Ikeja Electric seems to have the lowest target amongst its peers making the target unattainable.

Table 15: Ikeja Electric Proposed Loss reduction target:

Loss Reduction IE Projection:	2023	2024	2025	2026	2027	2028
Technical loss	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
Commercial loss	11.0%	10.5%	9.9%	9.4%	8.5%	6.7%

Collection loss	5.1%	4.9%	2.5%	1.2%	0.2%	0.2%
ATC&C	**19.6%**	**18.9%**	**16.4%**	**14.8%**	**13.1%**	**11.4%**

3.4. Treatment for divergence from planned ATC&C targets

Treatment of Divergence from planned ATC&C will be categorized as follows:

1. Divergence within the Control of the Disco:

   Where the divergence from the planned ATC&C targets occurs due to factors within the control of the DISCO; Ikeja Electric will be responsible to cover the shortfalls as a result of the extra losses incurred due to the divergence from set targets.

2. Divergence totally out of the control of the Disco:

   Where the divergence from the ATC&C target is as a result of factors totally out of the control of Ikeja Electric, such as force majeure by energy suppliers, community restiveness, major vandalization of infrastructure, labour unrest, pandemic, etc. the shortfalls arising will be recovered subsequently through the tariff structure, this will ensure and avoid further disruption to the business which can trigger further divergence to all set targets. The recovery mechanism will be within the tariff model, in cases where the losses can be directly attributable to a category of customers by distribution transformers, feeders, substations etc., the recovery will be limited to such category, otherwise will be treated as a general overhead cost across the network. Ikeja Electric will ensure utmost decorum in the application of the recovery and be mindful of the impact on the customers.

4. Operating Expenses (OPEX):

Based on our vested contract, Ikeja Electric (IE) is responsible for the largest portion of available grid energy, positioning the company at the forefront of providing energy to power the Nigerian economy. In order to continue fulfilling this role, the Company has planned network expansion and capacity growth to meet its regulatory obligations and corporate performance targets. To support these plans, the Company will continuously incur reasonable operating expenses (OPEX) responsibly to drive operations, asset replacement and deploy state-of-the-art technology, thereby improving operational efficiency and growth.

Unfortunately, the required OPEX to meet our regulatory and corporate obligations has far exceeded what was allowed within the Multi-Year Tariff Order (MYTO) in previous years, with an average shortfall of ₦25 billion per annum. Since taking over, IE has made significant investments in improving its network systems and infrastructure, with a focus on reducing Aggregate, Technical, Commercial, and Collection (ATC&C) losses. Considerable investments have been made in various areas including finance, human capital development, and acquiring cutting-edge IT infrastructure to enable automation. As a result, IE has successfully reduced its ATC&C losses from 41.3% in 2014 to 19.6% last year.

Strategic spending on operating expenses (OPEX) lines, majorly:

- Staff costs: which ensures we attract and retain specialized and highly sought after talent, with direct impact on the business growth and improved efficiencies.
- Customer service costs: these have contributed to a significant reduction in customer complaints. Monthly, over 90% of complaints are successfully resolved through our improved Customer Relationship Management Systems, also there has been a 49% reduction in average customer waiting time.
- Technical service and maintenance costs: The substantial investment in OPEX has enabled IE to promptly address power outages through enhanced and smart line tracing and fault finding, supported by its asset mapping (CEETAM)/GIS technology and technical proactive maintenance.
- Cash Collection Expenses: our revenue collection has grown significantly over the years due to our automated collection system, upgrades, improved collection channels and partners, all working together to grow the collection and manage payment systems whilst ensuring online/real-time customer account reconciliations and seamless payment support.
- IT Expenses: very crucial to the digital transformation of Ikeja Electric as a pacesetter within the industry, with visibility and synchronization of our grid and network assets, business, operations and customer support systems all targeted at improving and growing the business to world class standard.

4.1. Past Performance:

The allocated OPEX in the Multi-Year Tariff Order (MYTO) has been insufficient to enable Ikeja Electric to fulfill its regulatory obligations. Over the past 2 years, the following represents the disparity between the allocated OPEX line in the MYTO and the actual expenditure:

Table 16: Ikeja Electric 5 Years Actual OPEX:

IE ACTUAL	2019 =N='000	2020 =N='000	2021 =N='000	2022 =N='000	2023 =N='000
Fixed Costs	6,109,389	5,579,548	6,361,868	7,045,888	10,731,000
Admin costs (fixed)	11,647,425	11,409,056	12,512,727	15,246,438	17,494,000
Variable costs	14,032,531	16,274,730	18,429,576	21,662,356	36,047,000
Total	31,789,345	33,263,334	37,304,171	43,954,682	64,272,000

% Growth/(Reduction)				
Description	From 2019 to 2020	From 2020 to 2021	From 2021 to 2022	Projection 2023
Fixed Costs	-8.7%	14.0%	10.8%	52.3%
Admin costs (fixed)	-2.0%	9.7%	21.8%	14.7%
Variable costs	16.0%	13.2%	17.5%	66.4%
Total	4.6%	12.1%	17.8%	46.2%

Further to the hyperinflation experienced in 2023 with over 65% increase in exchange rate and inflation of 22.4% at a projected energy level of 4,726 GWh, operational expenses would be impacted by these factors.

Table 17: MYTO allowable 5 Years OPEX:

MYTO Allowable	2019 =N='000	2020 =N='000	2021 =N='000	2022 =N='000	2023 =N='000
Fixed Costs	2,791,100	2,902,744	3,018,853	3,139,607	3,265,192
Admin costs (fixed)	8,424,393	9,531,147	11,149,933	13,242,218	16,156,941
Variable costs	9,421,216	10,658,928	12,469,258	14,809,114	18,068,724
Total	20,636,708	23,092,819	26,638,045	31,190,940	37,490,856

% Growth/(Reduction)				
Description	From 2019 to 2020	From 2020 to 2021	From 2021 to 2022	Projection 2023
Fixed Costs	4.0%	4.0%	4.0%	4.0%
Admin costs (fixed)	13.1%	17.0%	18.8%	22.0%
Variable costs	13.1%	17.0%	18.8%	22.0%
Total	11.9%	15.4%	17.1%	20.2%

Table 18: Unrecovered OPEX:

OPEX Shortfall	2019 =N='000	2020 =N='000	2021 =N='000	2022 =N='000	2023 =N='000
Fixed Costs	(3,318,289)	(2,676,804)	(3,343,015)	(3,906,281)	(7,465,808)
Admin costs (fixed)	(3,223,032)	(1,877,909)	(1,362,794)	(2,004,220)	(1,337,059)
Variable costs	(4,611,315)	(5,615,802)	(5,960,318)	(6,853,242)	(17,978,276)
Total	(11,152,637)	(10,170,515)	(10,666,126)	(12,763,742)	(26,781,144)

In 5 Years		
Description	Average =N='000	Total =N='000
Fixed Costs	(4,142,040)	(20,710,198)
Admin costs (fixed)	(1,961,003)	(9,805,014)
Variable costs	(8,203,791)	(41,018,953)
Total	(14,306,833)	(71,534,165)

Table 19: Summary Comparison of Actual OPEX Vs MYTO allowable:

Description	2019	2020	2021	2022	2023
IE OPEX	31,789,345	33,263,334	37,304,171	43,954,682	64,272,000
Per MYTO	20,636,708	23,092,819	26,638,045	31,190,940	37,490,856
Shortfall- (N)	(11,152,637)	(10,170,515)	(10,666,126)	(12,763,742)	(26,781,144)
Shortfall- (%)	-35.1%	-30.6%	-28.6%	-29.0%	-41.7%

4.2. A review of the OPEX overhead item:

- ✓ Fixed Cost: *(ICT expense line item)*: A significant investment had to be made to acquire the necessary IT infrastructure in the past years, which has consistently improved the efficiency of our operations and customer satisfaction. Upon reviewing the breakdown of fixed operating expenses, it was found that the actual ICT expenses incurred exceeded the total fixed OPEX cost suggested in the MYTO model by over 107%, as shown in Table 20 below;

Table 20: Actual OPEX- Fixed Cost Overhead:

Description	2021 =N='000	2022 =N='000	2023 =N='000
Fixed Cost (MYTO)	3,018,853	3,139,607	3,265,192
Fixed Cost (Actual)	**6,361,868**	**7,045,888**	**10,731,000**
Data and Information Technology connectivity	2,864,753	3,369,999	3,816,000
% Of ICT Expense to MYTO Fixed OPEX	**95%**	**107%**	**116%**

One of the factors for the surge in the above line-item expenditure and other related expenses year on year is the exchange rate. Examples are most of the business software licenses and upgrades like the CIS v2.0, CRM, Oracle etc. that used for operational efficiency, are significantly settled in a foreign currency. Therefore, the Fixed cost amount quoted in the MYTO model is significantly understated and does not align with the current reality of the business.

- ✓ Fixed Cost Admin: *(Salaries expense line item)* - Strategic spending on OPEX lines such as staff costs has helped reduce customer complaints, with over 90% of complaints being resolved monthly and a 49% reduction in customer average waiting time. In order to support the business's goal of ensuring full customer satisfaction, the Company has consistently incurred OPEX expenses to recruit strategic positions and prioritize the welfare of its staff, thereby improving the efficiency of the company's operations.

However, it is worth stating that the customer-to-staff ratio in the years 2022 was 261:1. This has been a persistent challenge for the business and has made it difficult to meet and serve the needs of our customers. The high customer-to-staff ratio is also a significant factor contributing to the high staff turnover rate experienced within our network. Please refer to Table 21 below for more details.

Table 21: Ratio of Customers to IE Staff:

Description	2021	2022	2023
Customer Population	982,907	1,055,886	1,079,332
Number of Staff	4,145	4,042	4,480
Customer to Staff-Ratio	**237:1**	**261:1**	**240:1**

With the cap on the fixed Admin cost, the business is constrained in recruiting more staff to cater to the needs of our customers and unable to pay competitive remuneration to attract and retain competent and expert staff See below:

Table 22: OPEX- Fixed Admin Cost Overhead:

Description	2021 =N='000	2022 =N='000	2023 =N='000
Fixed Costs Admin (MYTO)	11,149,933	13,242,218	16,156,941
Fixed Costs Admin (Actual)	**12,512,727**	**15,246,438**	**17,494,000**
Salaries/Wages & Staff Cost	13,277,933	15,168,794	17,337,000
% of Salary/Wages exp. to MYTO Fixed Admin OPEX	**119%**	**115%**	**107%**

From the above table, the breakdown of the Fixed Admin expense reveals that the actual salary/wages expenses incurred exceeded the total fixed admin OPEX cost suggested in the MYTO model by over 119%, 115% and 107% respectively in the year 2021, 2022 and 2023, as shown in Table 22 above. Therefore, there is a need to reset the above line item in order to enable the business to deliver top-notch services to our customers and reduce the customer-to-staff ratio.

✓ Variable Cost: *(Sales & Collection expense line item);* In Table 23 below, a sample check of one of the line items in the variable cost (i.e., sales and collection expense) reveals that it accounted for 72% and 62% of the allowable MYTO variable cost suggested in the year 2021 and 2022, respectively. It's important to note that this is only for the sales and collection expenses, and there are other significant line-item expenses associated with the variable cost. Considering the current business reality and the call for an energy level increment, it is expected that the above-mentioned expenses will also increase. Therefore, there is a need to reset the expense overhead (variable cost) in order to enable the business to deliver top-notch services as the energy level increases.

Table 23: OPEX- Variable Cost Overhead:

Description	2021 =N='000	2022 =N='000	2023 =N='000
Variable Cost (MYTO)	12,469,258	14,809,114	18,068,724
Variable Cost (Actual)	18,429,576	21,662,356	36,047,000
Sales & Collection expense	6,625,510	6,937,821	10,280,000
% Sales & Collectn Exp. To MYTO Fixed Admin OpEx	53%	47%	57%

4.3. Implication of OPEX Shortfall:

The implications of the circumstances for Ikeja Electric's business are negative. Here are some of the key implications:

a. **Year on year Losses and erosion of net assets:** The continuous shortfall in operating expenses has resulted in a gradual erosion of net assets, as shown in Table 6 below. This situation poses a significant threat to the company's going concern status. Despite the company's growing revenue, the failure to recognize Ikeja Electric's prudently incurred operating expenses in the MYTO model has consistently led to a loss position.

Table 24: OPEX- Shortfall Implication:

OPEX VARIANCE IMPLICATION	2019 =N='Billion	2020 =N='Billion	2021 =N='Billion	2022 =N='Billion
PROFIT/(LOSS) FOR THE YEAR	158.41	8.78	-24.78	-6.97
NET ASSET	32.12	31.56	14.08	26.12

b. Increasing debt profile and liquidity challenges: The above issues have contributed to the company's continuous borrowing to survive, increasing debt and interest profile and the escalating liquidity challenges it faces. The inability to cover necessary operating expenses within the allowed limits has strained the company's financial resources and hindered its ability to meet obligations required to sustain its operations.

These challenges highlight the urgent need for a review and adjustment of the MYTO model to accurately reflect the company's operating realities and ensure its financial viability.

4.4. Six (6) Year OPEX Projection (2023- 2026):

Based on the prudently incurred expenses in the previous years (2021 and 2022) and considering the current economic reality of the business, projections for the next five years (2023-2028) have been made to determine the OPEX required to meet Ikeja Electric's revenue targets. These projections are compared with the MYTO estimates in the table below:

Table 25: MYTO 6 Years allowable OPEX:

	2023 =N='000	2024 =N='000	2025 =N='000	2026 =N='000	2027 =N='000	2028 =N='000	Yearly growth Assumption %
Fixed cost	3,265,191.77	3,395,799.44	3,531,631.41	3,672,896.67	3,819,812.54	3,972,605.04	4.00%

Admin cost (fixed)	16,156,940.65	19,713,217.93	24,052,261.47	29,346,364.65	35,805,744.07	43,686,886.72	22.01%
Variable cost	18,068,723.79	22,045,800.47	26,898,264.87	32,818,797.12	40,042,487.86	48,856,173.13	22.01%
Total	37,490,856.21	45,154,817.84	54,482,157.76	65,838,058.45	79,668,044.47	96,515,664.88	20.44%

Table 26: IE 6 Years OPEX Projection:

	2023 =N='000	2024 =N='000	2025 =N='000	2026 =N='000	2027 =N='000	2028 =N='000	Average Yearly growth %
Fixed cost	10,731,000.00	11,160,240.00	11,606,649.60	12,070,915.58	12,553,752.21	13,055,902.30	4.00%
Admin cost (fixed)	17,494,000.00	21,344,575.18	26,042,694.05	31,774,908.04	38,768,830.09	47,302,172.66	22.01%
Variable cost	36,047,000.00	43,981,245.09	53,661,883.65	65,473,311.42	79,884,532.87	97,467,784.26	22.01%
Total	64,272,000.00	76,486,060.28	91,311,227.30	109,319,135.04	131,207,115.17	157,825,859.22	19.68%

If the OPEX is not reset based on the cited business reality above, the shortfall in 2023 will exceed N26 billion, with an average annual shortfall of N42 billion over the next six (6) years. The table 27 below illustrates the shortfall between the current MYTO estimates and the actual projection by Ikeja Electric (IE).

Table 27: OPEX Potential Shortfall (MYTO Vs IE Projection):

	2023 =N='000	2024 =N='000	2025 =N='000	2026 =N='000	2027 =N='000	2028 =N='000
Fixed cost	(7,465,808)	(7,764,441)	(8,075,018)	(8,398,019)	(8,733,940)	(9,083,297)
Admin cost (fixed)	(1,337,059)	(1,631,357)	(1,990,433)	(2,428,543)	(2,963,086)	(3,615,286)
Variable cost	(17,978,276)	(21,935,445)	(26,763,619)	(32,654,514)	(39,842,045)	(48,611,611)
Total	(26,781,144)	(31,331,242)	(36,829,070)	(43,481,077)	(51,539,071)	(61,310,194)

Table 28: 5 years Potential Impact on Waterfall obligation if no review on the tariff:

Remittance Waterfall	2022 =N='Billion	2023 =N='Billion	2024 =N='Billion	2025 =N='Billion	2026 =N='Billion
NEMSF	4.61	12.6	9.97	8.26	8.11
NBET	100.13	225.84	254.88	284.52	317.92
MO	22.29	34.05	37.46	41.06	45.27

Depreciation	4.65	9.91	11.04	12.16	13.28
OPEX	43.95	64.27	76.48	91.31	109.31
RO Investment	10.69	24.17	39.61	45.09	50.63
Total Remittance	186.32	370.86	429.44	482.40	544.51
Deficit	(27.89)	(60.50)	(64.00)	(69.27)	(82.50)

Remittance Waterfall %

Breakdown	2022	2023	2024	2025	2026
NEMSF	100%	100%	100%	100%	100%
NBET	89%	88%	95%	96%	95%
MO	100%	100%	100%	100%	100%
Depreciation	100%	100%	100%	100%	100%
OPEX	85%	85%	85%	85%	85%
RO Investment	0%	0%	0%	0%	0%
Total Remittance	85%	84%	85%	86%	85%
(Under)/Over Recovery	15%	16%	15%	14%	15%

OPEX funding from waterfall cannot be less than 85% (as this are made up of mandatory fixed overhead cost necessary to keep the business running), while the balance of 15% can be funded through short term borrowings and vendors credit lines in order to sustain the proposed energy level and planned collection. However, any shortfall in recovery of OPEX from the tariff will result in the inability to meet market obligations (NBET and Bilateral Gencos), which will be unacceptable under the proposed the Bilateral contract regime and will cause a total collapse of the bilateral arrangement.

5. Weighted Average Cost of Capital Reset

Due to inadequacy of cost recovery from the MYTO tariff, the business in a bid to survive and keep the operations afloat must explore various means of funding for survival. The most readily available source of funding are the Commercial lenders, who are very skeptical to lending Discos because of the perceived high risk of loan recovery due to tariff inadequacy, fund escrow arrangement, customers apathy to payment and poor state of the financial position as shown the Audited Financial Statements.

Although with the intervention of NERC, this has improved with cleaner financial statements through tariff shortfalls set off against Market obligations and cost of sales, also with the approval and facilitating funding for the PIP, Commercial lenders have now become open to providing short-term funding to DISCOs perceived to be solvent. This debt comes at high interest rate due to risk premium place of DISCOs. Ikeja Electric in 2022 had to take these commercial loans as bridging funds to meet critical operational expenses, with interest rate of between 25% and 28% per annum.

Single digit cost of debt assumed by NERC in the tariff MYTO have significant impact on Ikeja Electric return on investment, recovery of cost and funding of operations, while NERC presumed a 9.7% cost of debt, cost of borrowing from these commercial banks is within 25% to 28% depending on risk attached to the corporate. MYTO should be updated to reflect our Disco's real cost of debt as demonstrated below:

Table 29: WACC Scenario if: CBN / Government funds 86% of 2023 CAPEX Requirement

Sources of Funding	Cost of Fund % Per annum	Amount N 'million	Cost of Fund per annum N 'million
Equity – from Internal generated funds	11%	1,577	173
CBN Funded under PIP	9%	31,370	2,823
Budgeted under DISREP	9%	7,777	700
Budgeted under SIEMENS Projects	9%	6,349	571
Vendor Financing/ Commercial Banks	25%	7,598	1,890
		54,671	**6,157**
Weighted Average Cost of Capital	**11.26%**		

Table 30: WACC Scenario if: CBN / Government funds 40% of 2023 CAPEX Requirement

Sources of Funding	Cost of Fund % Per annum	Amount N 'million	Cost of Fund per annum N 'million
Equity – from Internal generated funds	11%	1,577	173

CBN Funded under PIP	9%	21868	1,968
Vendor Financing/ Commercial Banks	25%	31,226	7,807
		54,671	**9,948**
Weighted Average Cost of Capital	**18.2%**		

Table 31: WACC Scenario if: CBN / Government funds 20% of 2023 CAPEX Requirement

Sources of Funding	Cost of Fund % Per annum	Amount N 'million	Cost of Fund per annum N 'million
Equity – from Internal generated funds	11%	1,577	173
CBN Funded under PIP	9%	10,934	984
Vendor Financing/ Commercial Banks	25%	42,213	10,553
		54,671	**11,710**
Weighted Average Cost of Capital	**21.4%**		

From the above scenarios, the Weighted Average Cost of Capital cannot be at single except CBN / government provides all the funds required by Ikeja Electric for CAPEX and short term OPEX intervention, which is not practicable in any instance, as shown above the DISCO's WACC is between 18% - 22% hence there is need to update WACC in the MYTO tariff model to position the business to be able to attract funds required for expansion and efficiency improvements, especially as we move to direct Genco bilateral contract regime, where access to funds will be critical to meet contractual obligations within stipulated times.

5.1. Capital adequacy / injection program including a consideration for the provision of payment guarantees to NBET and MO.

Currently Ikeja Electric operates on a negative working capital and the assessment of capital adequacy is less than 1, which means, we are not able to cover our immediate cash obligations as at when they fall due, caused by the under recovery of cost through the current tariff model as all parameters are no longer realistic. See table below for **abridged unaudited management account for 2022.**

Table 32: abridged unaudited management account

Abridged Unaudited Statement of Financial Position for the Year Ended December 2022		
Assets	**₦'m**	**Remarks**
Non-current assets	135,906	
Current assets	84,117	This includes Trade receivables, inventory and other advances (of the total receivable of N67b has been impaired)
Total Assets	**220,023**	
Equity		
Issued Share Capital	25	
Revaluation reserve	89,593	
Accumulated deficits	(201,895)	These are losses accumulated due to underrecovery of tariff over the years, gradually eroding the shareholders fund
Other reserve	131,393	
Total Equity	**19,116**	
Liabilities		
Non-current liabilities	47,843	
Current liabilities	153,064	
Total liabilities	**200,907**	This warehouses all the company debt as analysed long and short term
Total Equity and Liabilities	**220,023**	
Working Capital Adequacy Ratio	**0.55**	**Current Asset of N84b can only cover 55% of current liabilities of N153b when due,hence, working capital not adequate**

As we move into Genco full bilateral power purchase regime, it is pertinent to ensure that there is adequacy of working capital to meet contractual obligations within stipulated times, as cash deposit will also be required to seek Bank Guaranties to support the transactions, which will involve injection of funds.

For this to happen Ikeja Electric must be able to demonstrate to lenders and shareholders the viability of their investments, security of the funds and adequate return on their investments, hence the need to reset all targets to set the business on a journey of bankability and credibility. As the business as suffered loss of capital, erosion of funds over the years due to the under recovery in the current tariff structure.

Our lenders are willing to support with working capital once all the business parameters are realizable and realistic.

6. Summary:

Based on the findings presented above, we hereby propose a review of our current tariff parameters, as this review is crucial to the survival of the business now and even much more so as we move into direct bilateral contracting with GENCO's as the business is facing significant challenges that could potentially threaten its continuity if not addressed.

To avoid this, it would be more practical to implement a fully cost-reflective tariff regime, as this approach would bring the following advantages to NESI and the economy as a whole:

a.) This Disco continues as going concern, eliminating the risk of insolvency, continuous erosion of assets and shareholders' funds due to huge annual losses and threaten of unserviceable obligations.

b.) Shifting the burden of the real cost of energy from the government, relieving them of further financial commitments in terms of tariff shortfalls to industry, freeing up government resources to focus on more strategic economic expenditure.

c.) It would also guarantee the provision of sustained energy to customers commensurate in value, making the electricity supply in our network more reliable and more accessible. Improve customer service delivery and transforms customer overall experience.

d.) Ensuring the operational and financial viability of the Nigerian Electricity Supply Industry (NESI) as a whole, by ensuring the successful transition to full bilateral market, where all parties met their financial commitments and are adequately compensated for services rendered.

e.) Revamping the industry sets the business on a path of growth, transformation and operational efficiency and making it attractive for the required investments and partnership needed for growth, expansion and improved efficiencies.

Our prayers are summarized as follows:

- **Review of Energy:**

The projected energy levels in the MYTO model do not align with the actual energy levels of Ikeja Electric, considering the current network status and project implementation. Based on our analysis, **we propose 4,762 GWh for Ikeja Electric in 2023** and the projected incremental energy levels for the next five years, as shown in Table 1(c) above. It is important to note that achieving the MYTO energy level targets is contingent upon the availability of adequate funding, which has historically been lacking for network strengthening, capacity growth, and operational efficiency. Therefore, we kindly request a review of the energy allocation for Ikeja Electric within the MYTO model.

- **Reset of ATC&C loss target:**

The ATC&C loss targets utilized in the calculation of Ikeja Electric's tariff are not aligned with the current situation and do not reflect the reality of the business. Currently, there have been delays in implementing strategies aimed at reducing losses, such as insufficient Operational Expenditure (OPEX) to support revenue initiatives, a lack of liquidity to facilitate vendor financing for metering, franchising arrangements, and other infrastructure and technological enhancements intended to mitigate losses.

Due to the persistent disparity between our current ATC&C losses and the projected ATC&C losses in the MYTO, meeting our market obligations in their entirety would result in an inability to fully recover our costs and would pose challenges to our business operations and efficiency. Therefore, we strongly urge the commission to review and acknowledge our loss position and utilize a realistic loss forecast for Ikeja Electric from 2023 to 2028 in calculating the tariff, as shown in Table 2(d) above. We also request a cost recovery mechanism that incorporates the actual ATC&C losses of Ikeja Electric in previous years during the recalculation of our tariff shortfall.

- **Reset of OPEX and funding availability of CAPEX:**

The actual level of operating expenses (OpEx) and capital expenditure (CAPEX) required for the efficient operation of our business should be considered when designing rates in the pricing model. Based on our previous records in 2022, the OpEx specified in the MYTO for Ikeja Electric accounted for only approximately 58.1% of the actual OpEx utilized to run the business. This percentage is significantly lower than the OpEx required to operate a distribution company at the desired efficiency levels. Over the period from 2021 to 2022, the average annual unrecovered OpEx amounts to about N28.6 billion, contributing to recurring annual losses, liquidity challenges, and erosion of net assets.

Furthermore, the MYTO model does not provide sufficient CAPEX provisions to support the ambitious performance improvements required for the distribution company. The unavailability of CBN funds and the required foreign exchange have further hindered the initiation of major projects and weakened the business's liquidity position. The resulting gap, which must be financed, needs to be reflected in the pricing model. Therefore, we kindly request a review of our OpEx forecast and availability of CAPEX funding of projects for the years 2023 to 2028, as presented above in Tables 7(b) and 3(b) respectively.

In addition, we request that the cumulative OpEx shortfall incurred in the past years be recognized in the pricing model, and that a recovery mechanism be allowed for over a period of five (5) to seven (7) years. Another alternative is to recalculate the tariff shortfall and for the government to compensate Ikeja Electric and other affected Discos for these shortfalls.

- **Reset of Weighted Average Cost of Capital:**

MYTO model should be updated to reflect disco's real cost of debt, single digit cost of debt assumed by NERC had a significant impact on Ikeja Electric return on investment, operations and sustainability, it makes it difficult for the business to seek alternate funds as side CBN intervention which are not readily accessible and promptly disbursed when required. This as we have experienced in past years have slowed down the growth of the industry, impacted negatively on projects timelines and project costs. Eventually all the benefit of the cheaper funds are lost in variations due to inflation and changes in economic factors.

7. Impact on Reset Tariff:

If the realistic parameters are taken into consideration, Ikeja Electric's end-user tariff will be as shown in Table 8 below.

Table 33: Impact on tariff (MYTO vs IE Projection):

Weighted Average Tariff				
Year	Proposed MYTO ₦	Ikeja Electric ₦	Shortfall ₦	Variance %
2023	75.14	98.88	(23.74)	-32%
2024	77.49	98.20	(20.71)	-27%
2025	77.27	97.58	(20.31)	-26%
2026	77.02	99.33	(22.31)	-29%
2027	82.61	104.76	(22.15)	-27%
2028	85.26	107.33	(22.07)	-26%

Proposed weighted tariff of ₦98.88 per kwh for 2023 is significantly lower than an alternative source of power currently trading between ₦150 to ₦180 per kwh. Therefore, if Ikeja Electric is supported with the proposed tariff, would be reliable, affordable and more accessible cleaner energy for the end users.

Table 34: Weighted Average Tariff:

	2023	2024	2025	2026	2027	2028
IKEJA SUBCLASS DATA						
Energy Tariffs, N/kWh Before CS						
Category	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Life-line	4.00	0.00	4.00	4.00	4.00	4.00
A - Non MD	121.52	117.86	114.88	110.03	116.05	118.89
A - MD1	129.72	123.20	120.67	113.80	120.03	122.96
A - MD2	127.30	124.49	121.76	119.67	126.22	129.30
A - Bilateral	126.55	123.63	120.90	118.82	125.32	128.39
B - Non MD	109.22	109.09	104.99	96.47	101.75	104.24
B - MD1	110.41	110.45	106.83	105.00	110.74	113.45
B - MD2	121.91	123.63	120.90	118.82	125.32	128.39
C - Non MD	80.05	91.69	91.11	88.23	93.06	95.34
C - MD1	87.44	100.16	106.10	94.69	99.87	102.32
C - MD2	93.35	106.93	112.14	105.42	111.19	113.90
D - Non MD	54.61	62.55	79.31	81.52	85.98	88.08
D - MD1	79.16	90.68	87.82	86.32	91.04	93.26
D - MD2	79.16	90.68	88.80	87.27	92.05	94.30
E - Non MD	54.61	62.55	68.31	79.26	83.60	85.64
E - MD1	79.16	90.68	84.89	83.44	88.00	90.15
E - MD2	79.16	90.68	85.87	84.40	89.01	91.19

Table 35: Extract Revised Tariff Model Summary:

IKEJA SUBCLASS DATA

ENERGY AT WHICH SALES IS COLLECTED (NET EXPORT) ENERGY- IKEJA

	2023	2024	2025	2026	2027	2028
Delivered to Transco (GWh)	5,184	6,061	6,661	7,211	7,858	8,411
Delivered to Discos (GWh)	4,767	5,573	6,125	6,631	7,225	7,734
Collected Sales (GWh)	3,833	4,520	5,120	5,649	6,279	6,854

GENERATION & TRANSMISSION & DISCO COSTS (NET EXPORT) - IKEJA

	2023	2024	2025	2026	2027	2028
			12	13	14	15
Ikeja, %	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Capacity	106,229	122,256	136,220	151,596	180,856	197,847
Opex	132,316	147,980	165,557	185,387	192,631	211,596
Genco - Ikeja	238,545	270,236	301,778	336,983	373,487	409,442
Opex	7,777	9,638	11,751	14,278	16,700	20,415
RO Investment	(38)	128	232	349	22,203	24,605
Depreciation	22,642	23,626	24,432	25,230	25,816	26,597
Transco - Ikeja	30,380	33,392	36,415	39,857	64,719	71,617
Opex	4,172	4,561	4,984	5,467	6,033	6,689
RO Investment	178	228	250	274	302	335
SO	4,349	4,789	5,234	5,741	6,336	7,024
Opex	462	499	537	580	630	686
RO Investment	20	25	27	30	32	35
MO	482	524	565	610	662	721
Ancillary Service	700	1,016	1,378	1,837	2,466	3,248
Opex	64,643	77,201	92,504	111,168	133,944	161,755
RO Investment	24,174	39,606	45,086	50,626	57,780	63,368
Depreciation	9,915	11,040	12,160	13,281	17,323	18,443
Debt Repayment	5,776	6,066	4,533	1,051	1,051	-
Disco - Ikeja	104,508	133,913	154,284	176,125	210,098	243,566
Revenue Required	378,965	443,868	499,652	561,153	657,768	735,618
Average Tarriffs						
Average Tariff (N/KWh)	98.88	98.20	97.58	99.33	104.76	107.33