Performance Improvement Plan

For Ikeja Electric

Date 27th September 2019

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Acronyms

Acronym	Definition
AMI	Advanced Metering Infrastructure
ATC&C	Aggregate Technical, Commercial and Collection Losses
BPE	Bureau of Public Enterprises
BU	Business Unit
CAPEX	Capital Expenditure
CAPMI	Credited Advanced Payment for Metering Implementation
CIS	Customer Information System
CMS	Commercial Management System
CSR	Corporate Social Responsibility
Disco	Distribution Company
DT	Distribution Transformers
ERP	Enterprise Resource Planning
ESR	Energy Sales Representative
FEC	Federal Executive Council
FGN	Federal Government of Nigeria
Genco	Generation Company
GIS	Geographical Information System
H20	Harm to Zero (IE's corporate safety vision)
IE	Ikeja Electric
ISS	Injection Substation
IRMS	Incidents Recording and Management System
ISS	Injection Substation
IT	Information Technology
KPI	Key Performance Indicator
KYC	Know Your Customer
LT	Low Tension
MAP	Meter Asset Provider
MD	Maximum Demand
MDA	Ministries, Departments and Agencies
MO	Market Operator
MPR	Management Performance Review

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Acronym	Definition
MSA	Meter Service Agreement
MYTO	Multi-Year Tariff Order
NBET	Nigerian Bulk Electricity Trading Plc.
NEPA	National Electric Power Authority
NESI	Nigeria Electricity Supply Industry
NPF	Nigerian Police Force
NSCDC	Nigerian Security and Civil Defence Authority
P&C	Planning and Construction
PC&M	Protection, Control and Metering
PHCN	Power Holding Company of Nigeria
PP	Premium Power
PIP	Performance Improvement Plan
PPA	Power Purchase Agreement
QHSE	Quality, Health, Safety & Environment
RPP	Revenue Protection Project
SCADA	Supervisory Control and Data Acquisition System
SLA	Service Level Agreement
TUOS	Transmission Use of Service
UT	Undertaking
WACC	Weighted Average Cost of Capital
WMS	Works Management System

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1 One-page Summary for Stakeholders

During the privatization process, Sahara Group through a special purpose vehicle, New Electricity Distribution Company Limited (NEDC) (with KEPCO as its technical partner) acquired a 60% stake in Ikeja Electricity distribution Company (IKEDC) PLC in 2013. The company was subsequently rebranded in 2015 into Ikeja Electric Plc (IE) with 32% and 8% stake held by the Bureau of Public Enterprises (BPE) and the Ministry of Finance Incorporated, respectively.

Ikeja Electric is primarily responsible for the distribution of electricity to the mainland area of Lagos (Lagos North) and some parts of Ogun State. Our goal is to improve the quality of lives of our customers through the provision of reliable power and delivery of quality customer services. IE is responsible for maintaining, modernizing and strengthening our network grid, and ensuring that there is adequate capacity to support the needs of our customers.

Ikeja Electric is governed by a board of directors accountable to shareholders for creating and delivering sustainable value to our customers, employees and other stakeholders. We currently serve about a million customers and have a staff strength of about 3,100 dedicated employees.

The Ikeja Electric network is supplied from a transformation capacity of 2,375MVA from across 17 TCN transmission stations. 89 33kV feeders supply 33/11kV power transformers across 113 injection substations. There are 16,412 11/0.415kV distribution transformers and 1,302 33/0.415kV distribution transformers served by IE. The total transformational capacity of the 11/0.415kV and the 33/0.415kV distribution transformers are 3,499.9MVA and 991.9MVA respectively The route length for the 33kV, 11kV, and 415V feeders are 1,642.3km, 2,496.6km, and 5,927.4km respectively, resulting in a total route length of 10,065.2km.

Key outcomes from Ikeja Electric's PIP include the reduction of ATC&C losses to 8.8% by 2024, 100% metering of all customers by 2022 and the improvement of customer satisfaction to 95% by 2024. The investment requirements to achieve the performance agreement targets will result in a tariff increase that reflects our actual loss performance. This increase in tariff will enable us to successfully deliver our performance plan.

Over the next five years, Ikeja Electric plans to invest N105billion in its network 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.

Our strategy over the next years is to aggressively reduce losses by deploying meters across our network to improve energy accountability and collection efficiency. This is will coincide with the rollout of our premium power supply project across our network as we deliver reliable supply to customers. Our performance strategy will be achieved by driving our efficiency through innovation.

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2 Overview

We are committed to adequately powering Africa's most populous city, Lagos. We understand that our activities impact on millions of Nigerians and their businesses on a daily basis, so we are strategically driven to deliver improved standards of living to the numerous Nigerians who depend on our services by lighting up homes and businesses, thereby stimulating economic growth and development "BY BRINGING ENERGY TO LIFE".

For Ikeja Electric, we are committed to our vision of being the provider of choice wherever energy is consumed, and we remain dynamic and innovative in our approach to realizing this vison. Our goal is to generate and increase value for our customers, shareholders and other stakeholders in a sustainable manner while responsibly managing the socio-economic and environmental impacts of our activities. We are constantly improving on our service delivery and customer service standards while aiming at surpassing performance standards.

Since takeover we invested heavily in improving our systems and infrastructure geared towards improved service delivery and meeting our target baseline Aggregate, Technical, Commercial and Collection (ATC&C) losses. A huge amount of investment (funds, human capital development, etc.) has gone into acquiring leading edge information technology (IT) infrastructure to achieve automated systems geared towards eliminating the incidence of human errors in order to significantly reduce losses. This has culminated in a substantial improvement in the reduction of our collection and commercial losses, with an ATC&C target of 21.3% by the end of 2019, from between 39-41% which was submitted to NERC for the baseline loss study in 2014.

To consolidate on our successes which has focused on building customer and stakeholder confidence in our business and processes, and advance our vision of being the provider of choice wherever energy is consumed, our performance improvement plan focuses on reducing losses by driving efficiency through improvement in business processes by implementing strategies to actualize our goals over the next five years. Some of these goals include reducing out ATC&C to 8.8% by 2024, recording zero deaths and casualties to both employees and stakeholders in our coverage area, achieving 100% metering of all customers by 2022, and achieving at least 95% customer satisfaction.

Key challenges such as the lack of a cost reflective tariff, eligible customer declaration, customer apathy to payments, energy theft and meter bypass continue to plague our business and in effect, the market illiquidity being experienced by NESI. Our ability to attain our goals depends on the successful implementation of our risk mitigation strategies and obtaining the necessary regulatory support over the next five years. The challenges in the industry are daunting, the stakes are high, but we are determined to succeed.

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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.

2.1 Summary of process

Ikeja Electric has followed a robust process to prepare this plan and justify our planned expenditure. We have adopted a bottom up approach to developing our performance improvement plan by designing a strategy with inputs from stakeholders and all the departmental teams in Ikeja Electric. This approach fosters a shared sense of responsibility and deepens collaboration between both internal and external stakeholders, which are key ingredients required for the successful implementation of this plan.

Business planning has been aligned with stakeholder expectations to determine our achievable goals, the cost of implementation, manpower requirements, required technology to be deployed and the innovative approaches to maximise available resources to attain optimal operational efficiency and business performance.

We have also performed a risk evaluation of our business by considering the key challenges to the successful implementation of this plan and have designed risk mitigation strategy to enable us to attain our goals.

The process is described in more detail in Section 3.

2.2 Scenarios

This PIP considers two scenarios – one "no intervention" and one "with intervention" scenario.

The key characteristics of the two scenarios are:

- A business as usual scenario called "no intervention" based on NERC tariff assumptions from the latest minor review (June 2019), which treated the end of 2020 as year 4 of ATC&C loss reduction;
- A "with intervention" scenario based on a cost-reflective tariff, which recognises that tariffs have not permitted loss reduction to date (end of 2020 is treated as year 1 of ATC&C loss reduction) and allowing full required CAPEX to achieve the Disco's ambitious loss reduction and other output targets.

The "no intervention" scenario is currently the most probable, as it is consistent with NERC's public statements to date. However, the "with intervention" scenario allows IE to achieve their most ambitious output goals.

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The scenarios are described in more detail in Section 4.3.

2.3 Outputs with intervention

Over five years, the ambitious "with intervention" scenario will allow IE to:

- Reduce ATC&C losses from the current level of 26.0% to 8.8%, which will allow our business to be sustainable;
- Reduce the number of customer interruptions from the current level of about 11,000 in 2019 to about 3,500 by 2024, increasing reliability for our customers;
- Achieve 100% metering by 2022 by increasing the number of new meters installed to an average of approx. 268,000 per year by 2022, allowing customers to trust the bills they receive;
- Reduce the number of deaths and accidents in our service area to zero; and
- Increase the number of new customer connections from the current level of 63,749 per year between 2014 and 2018, to approx. 100,500 per year between 2020 and 2024.

These outputs are discussed in Section 4.4.

The justified investment plan to achieve these objectives is in Section 6.

2.4 Navigating this report

A map is required by the NERC Guidelines (p23)

> *Each Disco should include a section upfront explaining how its plan fits together. This should include a table that maps our assessment criteria to relevant parts of the plan and another that maps individual cost, output, uncertainty and finance areas to the relevant sections of the plan.*

Table 1: Mapping the structure of this report to NERC criteria

NERC criteria for evaluating the PIP	NERC questions for the PIP	Hyperlinks
Criterion 1 - Process	Has the Disco followed a robust process?	Section 3: Process
Criterion 2 - Outputs	Detail of individual outputs.	Section 4.4: Outputs: strategic objectives

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	Does the Plan deliver the required outputs?	Section 6: Detailed Program Plans
Criterion 3 - Expenditure	Are the costs of delivering the outputs efficient?	Section 6.2: Delivering outputs efficiently
	Detail of individual cost items.	Section 6: Detailed Program Plans Section **Error! Reference source not found.**
Criterion 4 - Financing	Are the proposed financing arrangements efficient?	Section **Error! Reference source not found.**: Funding Plans
	Detail of individual financing areas.	Section **Error! Reference source not found.**: Funding Plans
Criterion 5 - Uncertainty and Risk	How well does the Plan deal with uncertainty and risk?	Section 8.2: Approach to managing risk
	Detail of individual uncertainty area.	Section 8.3: Risk analysis

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3 Process

3.1 Overview

NERC PIP Guidelines p23:

> *Each section of the plan should have an overview and contents page. It should be easy for readers to get to the information they require (using hyperlinks).*

This section covers:

- Process for stakeholder consultation and engagement;
- Process for demand forecast;
- Process for setting output goals; and
- Process for investment planning.

3.2 Process for stakeholder consultation and engagement

> *The Disco is required to demonstrate clearly that in the preparation of the PIP, it has engaged stakeholders and that the outcome of such engagement has influenced the content of its Plan.*

As providers of an essential service and as users of natural resources, stakeholders expect electric utilities to build trusting relationships that will enable them to secure a social license to operate legitimately towards sustainability. Ikeja Electric considers it very important to sustain a healthy relationship with the communities in which we operate as such community engagements are critical for the successful delivery of the PIP outcomes over the next five years.

For the PIP, the purpose of our stakeholder engagements was to help Ikeja Electric better understand the aspirations, concerns and value of stakeholders. We used the opportunity to share vital information about our plans over the next five years and to gather feedback in the community. We were able to sensitize and enlighten customers on campaigns, products and services that will be made available to stakeholders in future. The opportunity allowed us to finetune our delivery strategy of an excellent customer experience by ensuring stakeholders complaints are resolved on time and promptly address issues trending online about Ikeja Electric. Key deliberations included resolution of issues with hostile communities for safety operation of Ikeja Electric staff in such communities. We also used the opportunity to address

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the media on campaigns and salient issues affecting customers to enhance the positive image of Ikeja Electric.

We adopted different approaches for different customer groups based on a critical study of methods of approach before engagement with clear a definition of our goals and objectives. We established the nature of information required from each stakeholder group and identified the messages we needed to convey. Information gathering was facilitated by implementing our engagement with effective communication and focusing on the "A" segments of our Q&A sessions.

Our stakeholder definition is based on several factors including demographics, influence, residential and non-residential customer type, organization and companies, intergovernmental agencies, local communities – Community Development Committees, Community Development Associations and traditional rulers, media, and associations.

Figure 1: PIP Stakeholder Engagement in Akowonjo BU

Figure 2: PIP Stakeholder Engagement in Shomolu BU

Key engagement risks that were planned for during the process include stakeholder management risk which can result from conflicting incentives and objectives of multiple parties, reputation risk which can arise from unfavourable views and notions about the objectives and mission of Ikeja Electric, and social risk from community resistance as a result of poor power supply and estimated bills. These risks were mitigated using strategies we have developed since takeover and which we intend to update and make more robust in the future. Some of these strategies include clear communication of the obligations of Ikeja Electric and stakeholder for better collaboration, involvement of stakeholders especially communities throughout the development and operation of new innovations, and partnerships with local organizations to facilitate the relationship between Ikeja Electric and stakeholders. Others include the involvement of local communities on project locations and construction scope,

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securing positive public opinion via transparency and involvement of local capacities and ensuring the accurate capture of stakeholder feedback. Feedback from the PIP stakeholder engagement was obtained from the open interactive sessions held with stakeholders. Annex A provides the detailed results of the stakeholder engagement.

For effective outcomes, feedback has been forwarded to the respective departments for action and internal meetings were organised to deliberate on the feedback. This approach enables us to enhance the mutual relationship between us and our stakeholders, increase motivation, provides value for the next line of action, helps formulate engagement policy for improved working relationships and aligns the goals and objectives of Ikeja Electric for better service delivery. Key topics raised through stakeholder engagement include efficient billing, pattern of power supply, faulty electricity distribution equipment, safety issues and bill payment.

In line with the feedback from stakeholders, our performance plan has been developed to ensure our outcomes are in sync with stakeholder expectations. Our electricity distribution plan has been designed to improve power supply reliability and ensure optimal equipment availability by utilising a detailed demand forecast to drive network investment. Our metering investment plan via MAP will deliver 100% customer metering by 2022 and thereby eliminate customer mistrust issues arising from estimated billing. Our commercial operations plan will see Ikeja Electric invest in state-of-the-art software that will guarantee efficient billing, incident reporting, customer complaint resolution efficiency, real-time equipment monitoring, operational efficiency and business cost visibility to enable cost savings. Our customer service plan will deliver customer interface platforms that facilitate 100% customer complaint resolution and improve revenue growth through the accurate capture of customer data. Our safety plan which enhances safety accountability at all levels, aims to deliver zero casualties through resourceful safety training programmes for both staff and stakeholders, and the procurement of quality safety equipment.

Over the next five years, Ikeja Electric will continue to build customer and stakeholder confidence in our business and processes by continuous engagement to ensure we capture feedback on our performance and by identifying new areas of service delivery improvement in line with our commitment to innovation.

3.3 Process for demand forecast

The problem faced by Discos in Nigeria is that due to the chronic shortages of power and in some cases unreliability of equipment, feeders are not always energised, and consequently only parts of the network are energised at any point in time. Consequently, the underlying *total* load is difficult to determine.

To combat this issue of sparseness in the data, IE modelled the time series of load of feeders using a "structural model". The Structural Model approach calculates the Unsuppressed Demand by forecasting the demand that would otherwise exist on the disconnected feeders if they were connected. Figure 3 and Figure 4 demonstrates how demand is “reconstructed” for one feeder by filling in missing periods with the value predicted by the structural model. The structural model is described in more detail in Annex C.

Figure 3: Ishaga feeder readings

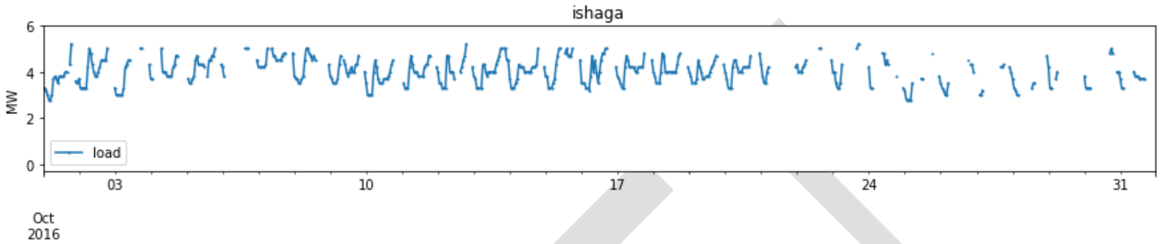

Figure 4: Ishaga feeder readings and forecasted series

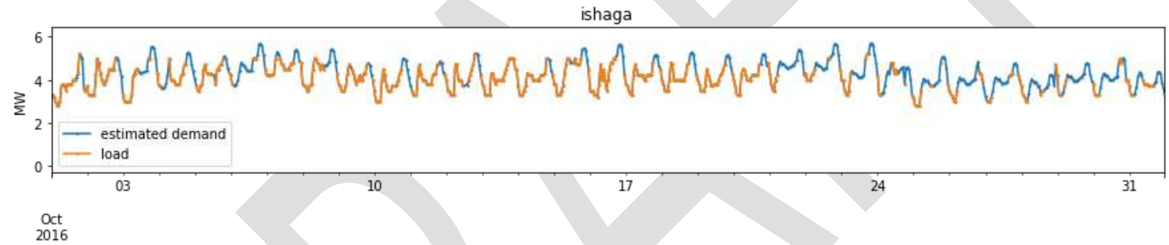

Table 2 shows the summary of the structural model results against the raw data, and the suppressed demand. Analysis of the raw data reveals a simultaneous peak demand of 688MW which occurred on the 26th of October 2018 at 7pm, while the structural model gives an unconstrained simultaneous peak demand of 1,119MW. Analysis of the raw data reveals a non-simultaneous peak demand of 1,251MW, while the structural model gives an unconstrained non-simultaneous peak demand of 1,444MW. This gives a supressed simultaneous peak demand of 430MW, non-simultaneous peak demand of 193MW, and suppressed energy of 3.4TWh.

Table 2: IE Peak Demand Summary

Data Source	Simultaneous Peak Demand (MW)	Non-Simultaneous Peak Demand (MW)	Energy (GWh)
Structural Model (Unconstrained)	1,119	1,444	7,474
Demand Supplied (Raw data)	688	1,251	4,068
Suppressed Demand	***430***	***193***	***3,406***

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Defining this baseline then allows for future demand projections of unconstrained demand. In order 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 over 2018. These potential customers per tariff class are applied to both 11kV and 33kV feeders over the 5-year forecast resulting in a customer growth from 1.0 Million in 2018 to 1.4 Million in 2024, representing an increase of 42% and summarised in Table 42.

A dynamic regression model, described in Annex C, is applied to each feeder on the IE network to generate its hourly demand using the hourly regression coefficients, for each customer tariff category generated in the baseline year (2018). This methodology assumes a constant level of customer electrical appliance ownership over the forecast period, which is reasonable given the unresponsive relationship between GDP and electricity demand in Nigeria given the poor historical supply of on-grid energy. Essentially it looks at the temporal relationship between customers on a feeder and the feeders' hourly demand in the baseline year, to project the demand of feeder for the same period in future years. This feeder by feeder forecast approach allows IE to assess the levels of unsuppressed demand across the network, providing a basis to determine which feeders are unable to be fully served by TCN injection stations over the forecast period, in a bid to plan potential grid supply augmentation mechanisms at or across those feeders. This methodology allows the effect of each additional customer on IE's network to be individually analysed in each hour over the forecast period, providing a robust assessment of demand growth. This methodology also captures the seasonal effects of external temperature on demand ensuring that annual variations in demand due to climatic changes are captured. In the current analysis, projected temperature values have not been used, however, this can be included in future analysis.

The dynamic forecast approach allows for a projection of both the simultaneous and non-simultaneous peak demand given in Table 43.

3.4 Process for setting output goals

Our stakeholder engagement process provided feedback on the customer priorities and informed our overall strategy which is to deliver a reliable energy service and guarantee customer satisfaction. In order to define our goals, we assessed our performance against our performance agreement with the Bureau of Public Enterprises (BPE) to identify key successes and challenges for unattained KPIs. A demand and energy supply gap analysis was performed, which was fed into the network expansion plan to determine network infrastructure investments. Investment plans and innovative strategies to meet other KPIs including loss reduction, MAP support and customer connections were then developed.

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Our investment plans were then prioritized using the feedback from stakeholders, supported by an optimal plan for network expansion. The impact of our investments and outcomes on tariffs and business performance were assessed using two scenarios with different ATC&C loss trajectories. The feedback on our planned outcomes were then shared with stakeholders who gave feedback, and which has been used to finalize our performance plan.

3.5 Process for investment planning

Our investment plan is guided by our strategic pillars and initiatives

1) Building a Customer Centric System
    - The WOWE (WOW Experience)
    - Managing Customer Complaints
    - Connecting with
2) Entrenching a Safety Culture
    - Safety Monitoring and Compliance Audit
    - ISO1400:2015 Certification, OHSAS 18001 and ISO 9001:2008QMS
    - Safety Mentorship and Empowerment
3) Running a Financially Sustainable Business
    - Responsible Procurement Practices
    - Managing Commercial and Collection Losses
    - Metering
    - Billing and Collection Efficiency
    - Demand Side Management
4) Engaging with Local Communities
    - Protective Communication and Engagement
    - Personal Corporate Social Responsibility
5) Building a Sustainable Workforce
    - Talent Management and Succession Planning
    - Performance Management
    - Learning and Development
    - Culture Change Management
6) Building Stable Networks and Improving Infrastructure
    - Investing in our Network
    - Strengthening our Network
    - Expanding our Network and improving access to electricity
    - Leveraging Technology
    - Measuring our Performance
    - Managing Technical Losses

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The objective of our investment planning process is to deliver cost efficiency through innovative strategies implemented using a least cost plan that guarantees optimal returns, operational efficiency, safety, excellent customer experience and sustainable energy supply. The liquidity challenges currently being experienced by NESI requires financial prudence and sensible utilisation of scarce capital to underpin our investment plans.

The budget and investment planning process of Ikeja Electric is an all-encompassing one that seeks to ensure all the budget owners have input into the final budget document. The objectives of the budget process include the following:

1. To ensure improvement in operational efficiency.
2. To achieve performance targets.
3. To ensure optimal utilisation of the network.
4. To ensure network strengthening and expansion.
5. To improve metering.
6. To ensure correct energy accounting.

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The overall budget strategy for the period is determined by the IE management and communicated to the business. Inputs including stakeholder feedback are received from the various departments and/or units are reviewed and evaluated. The various assumptions including economic, tariffs, power generation are included. Technical capital expenditure is evaluated to determine profitability.

All the inputs are consolidated into the companywide budget. The budget is reviewed by IE management and subsequently approved. The approved budget is communicated to the IE board for the approval. Upon approval, the budget is signed by the board. The signed budget is communicated to the business for implementation. The following sections detail the summary of our processes in developing our investment plan.

3.5.1 Process for electricity distribution planning

Electricity distribution investment will help Ikeja Electric achieve the following targets:

- Reduce ATC&C losses from the current level of 26.0% to 8.8%, which will allow our business to be sustainable;
- Reduce the number of customer interruptions from the current level of 10,845 in 2019 to 3,554 by 2024, increasing reliability for our customers;
- Increase the number of new customer connections from the current level of 63,749 per year between 2014 and 2018, to 100,601 per year between 2020 and 2024.

Our distribution network investment planning process is driven by the need to optimise available capital, leverage technology, and employ innovative strategies in guaranteeing maximum availability and operational efficiency of our network assets. Our network investment strategy is guided by our demand forecasts and network constraints analysis to deliver reliable power supply and significantly reduce technical losses. Our demand assessments enable us to understand the trends in energy consumption across our coverage area, and their short- and long-term impacts on our network.

By accurately determining demand growth patterns across our network and by customer categories, Ikeja Electric can structure its infrastructural investment plans to deliver a good balance between demand and supply, siting of new projects and timing investments to deliver optimal services. The various outcomes of our methodological demand and load flow studies, sets up the basis by which Ikeja Electric designs and implements plans to expand and/or modify our network to meet customer demand expectations and increase service delivery excellence.

Our five-year network expansion plan has been designed to meet our demand forecast of 2,824MW by 2024 – see section 4.3.1. Our plan, through the upgrade of existing network infrastructure, including radiation of new 11 and 33kV feeders, capacity upgrades at injections substations, construction of new injection substations and the deployment of new distribution stations, will enable us guarantee efficient service delivery in our coverage area. Our investment plan is discussed in more detail in Section 5 and Section 6.

3.5.2 Process for commercial operation planning

NERC has set out expectations for several software applications to support commercial operations. The status of applications used for IE's operations are captured below

- Incidents Recording and Management System (IRMS): IE currently logs customer complaints and issues from dispatch, however IE plans to deploy an enterprise resource planner (ERP) from Oracle by 2022, Oracle Smart Grid Footprint, that comprises of a commercial management system (CMS), IRMS, Revenue protection and works management system (WMS) - Figure 5.
- Commercial Management System (CMS): IE has a system with adequate functionality for commercial management, however without modules for meter management and information system. These functionalities will be added by 2020 and 2021 respectively.
- Enterprise Resource Planning (ERP): IE currently has four applications that manages procurement, human resource, finance and inventory information, with a view to implementing an ERP by 2022.

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- Geographical Information System (GIS): IE currently uses ArcGIS by Esri, equipped with a customer and asset database. IE has plans to extend its functionality to include a network database.

- Supervisory Control and Data Acquisition System (SCADA): IE plans for a phased implementation of SCADA to be completed by 2024. The planned phases are detailed in Section 6.5.5.

- Works Management System (WMS): IE currently has three distinct tools, IE Force, CRM and Mobi works which together deliver WMS capabilities. The ERP to be procured by IE includes a WMS.

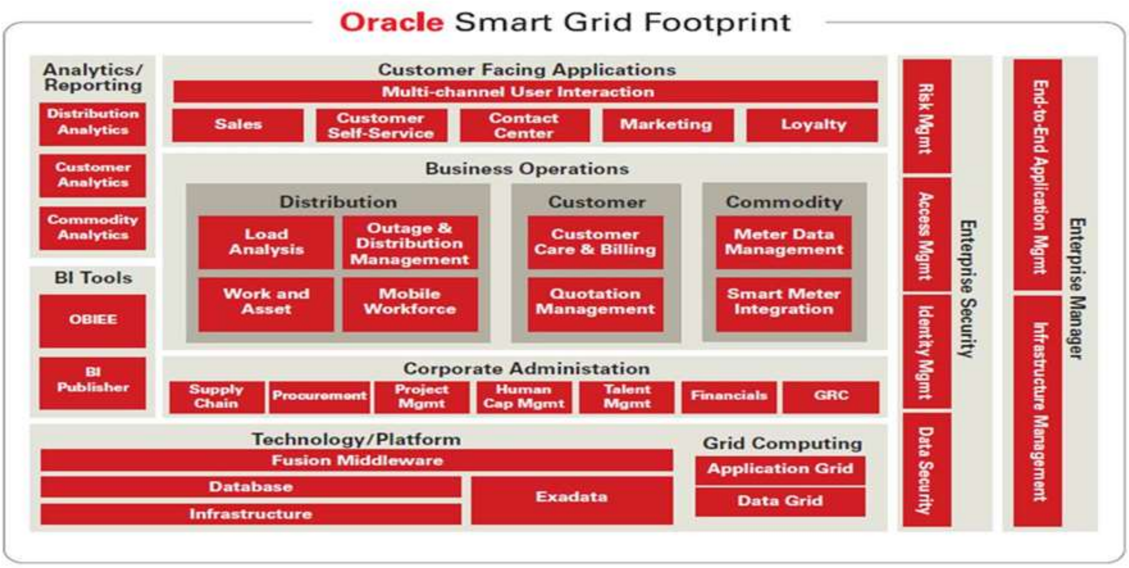

Figure 5: Oracle Smart Grid Footprint

The IRMS will provide efficiency in the logging, tracking and resolution of customer complaints with a plan to reduce customer interruptions from 8,676 in 2020, to 3,554 in 2024, and guarantee optimal customer satisfaction, with an improvement in customer complaint resolution from 85% in 2020, to 95% in 2024. The GIS system will provide an active customer and network database that integrates the mapping of network assets to other network infrastructure, and connectivity of customers to network distribution assets. The mapping of customers to network assets will aid in timely complaint and fault resolution which will leverage the detailed mapping of the network topology. Using our customer database, customer enumeration, new connection management, billing and regularization services will be provided efficiently and promptly. The SCADA system contributes to increase quality and reliability in electricity supply and reduce operating costs. It provides real-time visibility of network infrastructure and significantly reduces the effort and cost associated with fault resolution, thereby improving energy throughput to consumers, increasing customer satisfaction and willingness to pay.

The ERP system comprising of business unit modules including finance, logistics, procurement and human resources will provide an integrated platform that delivers operational cost visibility, cost efficiency management, timely business operations data for decision making and productive business operations management. Systems that will enable IE guarantee cost efficiency in its operations are vital in aiding IE to achieve its market remittance commitments, deliver profitable returns for its shareholders and efficient service to its customers.

The CMS system is key in monitoring and improving billing efficiency as it provides accurate and real-time visibility of energy sales, customer consumption, metering data to track performance and accuracy of energy consumption which will support the planned ATC&C reduction from 26.0% in 2020 to 8.8% in 2024.

3.5.3 Process for meter investment planning

Meter investment via Meter Asset Providers will help IE achieve the following targets:

- Increase the number of new meters installed to an average of 268,728 meters per year, allowing customers to trust the bills they receive.

IE has a total metering gap of 1,074,411, and has contracted three Meter Asset Providers, CIG, Mojec and New Hampshire to deliver and install customer meters over a 36-month period, to be completed by 2022.

The actual MAP plans are discussed in section 6.

3.5.4 Process for safety investment planning

Health and Safety investment will help IE achieve the following targets:

- Reduce the number of deaths and accidents in our service area to zero.

With IE's mission and corporate safety vision tagged Harm to Zero (H20), IE plans to continue the reduction of electricity related fatalities to both staff and stakeholder within its franchise area, to zero. The H20 vision is supported by safety programmes such as the "Beyond Zero", which enhances safety accountability at all levels; i-Empower (QHSE Academy), which is an employee initiative to develop in-house safety leads companywide; and "What Went Wrong", a safety feedback mechanism used to improve business safety processes.

Over the next five years IE intends to complement recent achievements through a combination of detailed and resourceful safety training programmes for both staff and stakeholders, and the procurement of quality PPE that will protect staff from health and safety risks. New health and safety initiatives will also be developed to mitigate any identified risks and ensure the safety of life.

The actual H&S plans are discussed in section 6.

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4 Introducing the Context for this PIP

4.1 Overview

This section covers:

- Introduction to Ikeja Electric;
- Scenarios in this PIP
- Strategic objectives; and
- Challenges.

This chapter provides the information required by NERC in an "introductory chapter".

4.2 Introduction to Ikeja Electric

4.2.1 Vision

To be the provider of choice where energy is consumed.

4.2.2 Mission

The provision of quality and reliable services to our customers and adherence to the highest standard of safety at all times.

4.2.3 Overall strategy

IE effectively drives its commitment to deliver efficient and sustainable power supply through investments in new technology, infrastructure upgrade, and human capital development.

4.2.4 Business environment 2013-2019

Following the privatization of the distribution companies in November 2013, the Discos have continued to operate in an adverse business environment which has led to limited progress in the performance improvement of the Discos. Some of the factors that have made the business environment very challenging are discussed below.

4.2.4.1 *Lack of cost reflective tariff*

At the time of privatization of the Discos, the Multi Year Tariff Order II (MYTO II) was in effect. However, it became clear during the privatisation process that the key assumptions of the MYTO II (including generation levels, ATC&C losses and customer numbers) were inaccurate and resulted in tariffs that were not cost reflective. Since the true PHCN performance was not known, NERC and BPE agreed that the new owners of the Discos should carry out a study to determine their baseline losses and real customer numbers at the time of privatization, and this would be the basis of a tariff reset. Unfortunately, the results obtained for the Baseline ATC&C loss was significantly reviewed upward from 39% - 42% as submitted by IE to 33% by NERC.

Despite this commitment, the full cost of the electricity value chain has never been allowed to pass-through to tariffs since privatisation. Table 3 shows a summary of the major events that mean tariffs have not been cost reflective. Table 41 in Annex B provides a more detailed timeline.

Table 3: Summary timeline of key tariff challenges

Year	Tariff cost reflective?	Events
2013	No.	– Privatisation process recognised that tariff review would be required once true level of ATC&C losses were understood. Interim Rules Period (IRP) introduced to recognise Disco's inability to pay the market until tariffs were cost reflective. The deficit in MYTO 2012 was never funded. That meant a revenue deficit from the very beginning of the implementation of the order.
2014	No.	– Discos conducted Baseline Losses Studies to determine true levels of ATC&C losses.
2015	No. Only 2 months (February and April) where tariffs were close to cost reflective.	– Commencement of TEM in February 2015. Discos were expected to pay full market invoices from this date. – February 2015 was the start of revised tariffs based on a new tariff model known as MYTO 2.1 which recalculated tariffs based on the results of the Disco's baseline losses study. However, MYTO 2.1 assumed that the Discos has started their loss reduction path in January 2013. This meant that tariffs were not truly cost reflective. – In April 2015, tariffs are amended to strip out collection losses. The removal of collection loss led many of the Discos to issue notice of Force Majeure under their Performance Agreements in 2015. – Minor reviews not implemented.
2016	No. MDA debts still not resolved.	– New MYTO 10-year tariff order from February 2016, reinstated most collection losses but reduced allowed losses by removing Ministries, Departments & Agencies (MDA) debt. The intention was for FGN to pay these historic liabilities and introduce a mechanism to meet future

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Year	Tariff cost reflective?	Events
	Minor reviews not implemented.	bills. Addresses one of the flaws of MYTO 2.1 by adjusting the assumed first year of loss reduction from 2013 to 2015. – From March 2016, generation dropped dramatically as a result of insurgency, Discos revenue decreased dramatically as a result of less power to sell. – From May 2016, foreign exchange weakens considerably, and PPA indexation means cost of generation jumps from 12 N/kWh to 18 N/kWh. – Six monthly minor reviews in June and December were not implemented, these should have incorporated the impact of the generation level and foreign exchange in retail tariffs.
2017	No.	– Six monthly minor reviews in June and December were not implemented in tariffs. – MDA payments have still not been resolved.
2018	No.	– Tariff freeze in January 2018, when NERC instructed the Discos to freeze their tariff at the 2017 level. – Six monthly minor reviews in June and December were not implemented. – MDA payments have still not been resolved.
2019	No.	– Six monthly minor review in June was implemented, but revised tariffs were delayed until January 2020, so tariff remains not cost-reflective. – MDA payments have still not been resolved.

The NERC tariff review process was designed with the intent to undertake major reviews every five years, with an extraordinary tariff review triggered by a Disco's need for additional investment outside the allowed capital expenditure, and also to allow encountered unforeseen operational, legal or regulatory costs to be reasonably passed on to the consumers. This is in addition to minor reviews which are to occur every six months to adjust tariffs for changes to the gas price, the foreign exchange rate, generation output, and inflation. The minor reviews have not been implemented since the release of MYTO 2015 and as a result, tariffs continue to slide further below cost-reflective levels, undermining the Discos ability to fulfil their obligations under the Performance Agreements and Vesting Contract.

There is inadequate CAPEX provision in the MYTO model for the ambitious performance improvement required. It is hoped that this PIP will form the basis for revised CAPEX.

The lack of a cost reflective tariff has resulted in accrued liabilities of N203.2Bn to NBET and MO, accumulated losses of N350Bn and working capital deficit of N246.8Bn that have really inhibited bankability. This means that Discos are unable to raise finance for performance improvement.

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4.2.4.2 *Eligible Customers*

The eligible customer regulations will allow large ("eligible") customers to purchase power directly from generating companies. Large customers are a major source of revenue for Discos due to their ability and willingness to pay, and heavy cross subsidies between tariff classes. Although a Competition Transition Charge and Distribution Use of System Charges were intended to address the financial impact of losing these customers, they have not yet been put in place.

Under the regulations, eligible customers are required to apply to NERC for eligible customer status, with their proposed supplier. NERC has not officially granted eligible customer status to any customers yet, but eligible customers are still taking advantage of this new policy. Since 2018, Discos have been reporting that some transmission-connected customers are defecting without approval from NERC. Ikeja Electric currently has 34 customers at risk, with a monthly risk impact of N1.07billion. We are aware of at least six cases across different Discos in which these customers are refusing access to the Disco to read meters and invoice them for demand. If the customers do have a PPA with a provider to supply them power, the Market Operator would need to be aware of it and account for it in Settlement Statements.

4.2.4.3 *Customer perceptions*

The lack of liquidity has resulted in an adversarial public discussion, with various participants blaming others. This has reinforced negative customer perceptions, and together with a perception of electricity as a public good that should be consumed freely, has led to low willingness to pay, energy theft, meter bypass and vandalization of power assets. This is exacerbated by insecurity in some areas of operations. This is inclusive of Government Ministries, Departments and Agencies (MDAs).

The sector should try to present a more unified vision in the future, to support customer confidence and encourage customers to pay their bills.

4.2.4.4 *Policy and regulatory uncertainty*

The regulatory framework in Nigeria has changed very rapidly since 2013. There is a need for regulatory stability, and for regulations to be applied consistently. We recommend:

- The MYTO minor reviews should be implemented in tariffs every six months, without delay;
- Conditions precedent should be met – the conditions for the TEM were not met before it was declared. This materially contributed to the failure of participants to meet their obligations;

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- New regulations such as Eligible Customers and Meter Asset Providers (and in the future potentially Franchising) have increased the number of players in the sector, but it is not yet clear that they will increase investment unless the resulting risks are reduced;

- Proposed regulations, the Business Continuity Regulations, may make it impossible to raise finance in the sector;

- Transparency is essential – instructions by NERC to specific market players (such as the MO or NBET) should be made public and consulted on – as they may result in changes to market charges that are not reflected in retail tariffs; and

- The pace of regulatory change should be slowed, and full regulatory impact assessment conducted, so that new regulations do not have unintended consequences, such as worsening the ability of market participants to raise capital or reducing the liquidity of the sector.

4.2.5 Description of achievements 2013-2019

2014 Achievements

- By strengthening the distribution network, we were able to reduce the frequency of electric service interruptions to our customers by 21% 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.

2015 Achievements

- Reduction in the frequency and duration of electric service interruptions to our customers by 62% and 21%, respectively.

- Implemented an improved organizational model that was geared towards increasing the number of customer touchpoints 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.

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- Centralization of billing operations as means of driving more operational efficiency and reducing losses.
- Over 4,000 MD meters were installed (2344 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.

2016 Achievements

- "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.
- Expansion of platforms for customer engagement, which included the introduction of the Live Chat platform
- Continuation of the Customer Enumeration, Technical Audit and Asset Mapping exercise (CETAAM)
- 60% 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%
- Continued metering. Over 32,000 customer meters were successfully installed in 2016.
- Success completion of both the Occupational Health and Safety Assessment
- Series (OHSAS) 18001:2007 and ISO 9001:2008 Stage 1 Audit.

2017 Achievements

- Reduction in ATC&C losses from 49.2% in 2016 to 38.62% in 2017
- Business process automations such as Mobi works application, Estimated Billing Methodology EBM software, Meter Reading software,
- 744 meters deployed under the Debt-for-Metering scheme
- OHSAS 18001:2007 certification.
- ISO 9001:2008 Certification

2018 Achievements

- Reduction in ATC&C losses from 38.6% in 2016 to 31.8% in 2018

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- Established and inaugurated functional i-Empower (QHSE Academy) to help develop in-house safety leads (Safety Leadership Team) companywide.
- 22,248 meters installed under the Debt-for-Metering scheme
- Launched Beyond Zero, Take Ownership programs and i-SAFE App for easy and faster escalation of hazards.

2019 Achievements

- Reduction in ATC&C losses from 31.8% in 2016 to 26.5% in 2019 August YTD
- Successful establishment of a fully operational customer care unit with walk-in centres; call centres, 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.

4.3 Scenarios in this PIP

There are two scenarios considered in this PIP:

- A business as usual scenario called "no intervention" based on NERC tariff assumptions from the latest minor review (June 2019), which treated the end of 2020 as year 4 of ATC&C loss reduction. In our financial analysis, we present two outcomes of this scenario where in outcome one, Ikeja Electric cannot fund CAPEX (Zero CAPEX) and Ikeja Electric borrows to fund CAPEX (MYTO CAPEX);
- The second, "with intervention" is based on a cost-reflective tariff, which recognises that tariffs have not permitted loss reduction to date and allowing full required CAPEX to achieve the Disco's ambitious loss reduction targets. We present this one outcome of this scenario as Full CAPEX with Ikeja Electric able to fully finance its required investments.

In the "no intervention" scenario, it will not be possible to achieve the full ATC&C loss reduction improvement. The "with intervention" scenario allows more ambitious levels of loss reduction and performance against other outputs.

Cost-reflective average tariffs and payments to the market (expected % payment to MO and NBET) are outputs of both scenarios.

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In our scenario analysis, we assume we can retain all our customers as modelled in MYTO 2019 and do not include the impact of eligible customer attrition on our financial performance. Ikeja Electric has 37 customers at risk, with a monthly risk impact of N1.07billion.

The two scenarios are summarised in Table 4.

Table 4: Summary of the two scenarios

Assumption	"No intervention" scenario NERC tariff assumptions for ATC&C	"With intervention" scenario Cost-reflective tariff and full CAPEX	Detailed description
Demand	Consistent demand scenario		Section 4.3.1
Generation levels	Stable at 2019 levels		Section 4.3.2
Generation tariffs	Increasing with foreign exchange; increasing due to additional capacity charges once PPAs are activated		Section D. 1
Tariffs	Tariff assumes NERC's ATC&C loss reduction trajectory with the end of 2020 as year 4 of ATC&C loss reduction	Cost reflective tariff from Jan 2020 with 2020 as year 1 of ATC&C loss reduction	Section 7
Allowed CAPEX	MYTO levels	IE proposed levels in 2020-2024	Section 7
Access to capital	70% debt; 30% from free cash flow	70% debt; 30% from free cash flow	Section 7
Actual ATC&C	2020 is year 4 of ATC&C loss reduction; limited access to capital means slow loss reduction; no solution for MDA payment	2020 is year 1 of ATC&C loss reduction; full CAPEX means faster loss reduction; FGN solution for MDA payment in place	Section 7

4.3.1 Demand forecast

The unconstrained non-simultaneous peak demand of Ikeja Electric is expected to grow from 1,444MW in 2019 to 2,248MW by 2024 representing a growth of 56%, as shown in Figure 6. Similarly, the simultaneous peak demand is expected to grow from 1,119MW in 2019 to 1,793MW by 2024, representing a growth of 60%. This translates to an unconstrained energy consumption increase of 72%, from 7.4TWh in 2019 to 12.8TWh in 2024.

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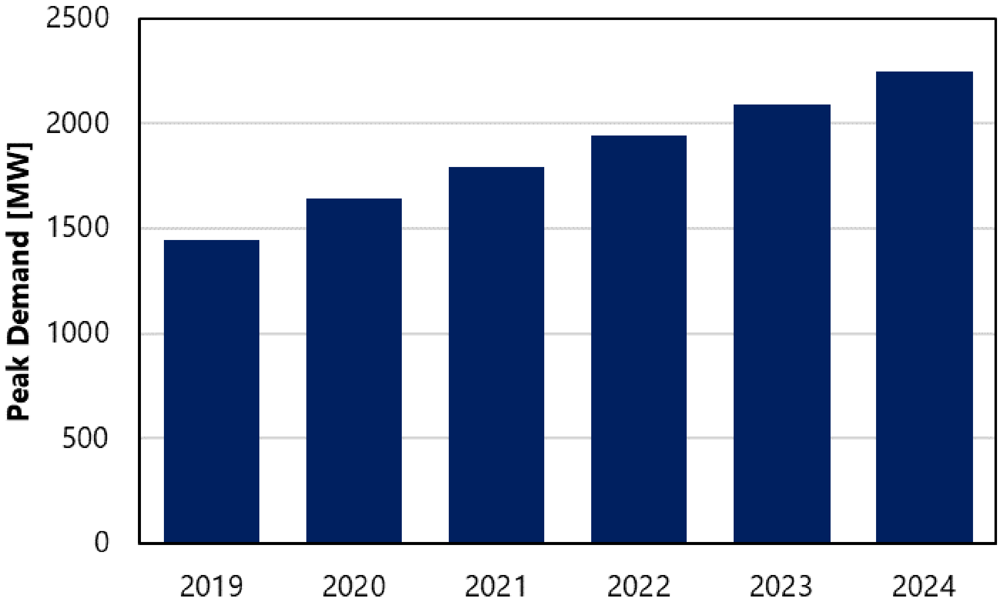
Figure 6: IE Non-simultaneous Peak Demand (MW) 2019-2024



The customer and demand forecast projections are detailed in Annex C.

Demand forecasting is a significant step in the power planning process as investment risks are sensitive to the accuracy of forecasts. If future demand growth is underestimated, this may lead to under-investment in network infrastructure resulting in over utilisation of network assets and an increase in unplanned maintenance and replacement costs. If future demand growth is overestimated, this may lead to over-investment in network infrastructure resulting in underutilisation of network assets and a sub optimal use of scarce investment resources.

We expect greater demand certainty once meters are fully deployed to all Ikeja Electric customers. The demand forecast methodology adopted by IE captures the discrete temporal changes in consumption patterns and will be reflected in our annual analysis as stipulated by the Distribution Code. This will allow for adequate adjustments to our plans if there are any significant deviations from our projections.

4.3.2 Generation

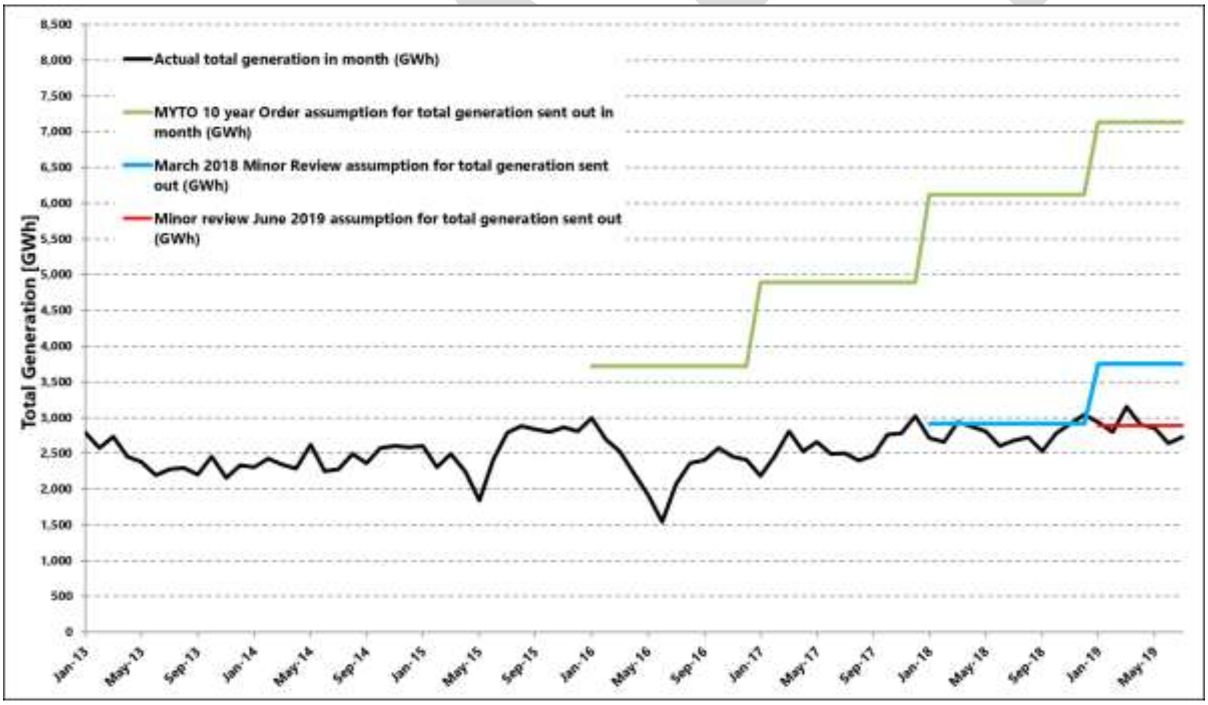
4.3.2.1 *Energy generation*

Table 5: Ikeja Electric forecasted power delivered by TCN

	2019	2020	2021	2022	2023	2024
Power Received from TCN (GWh)	3,784	5,855	6,387	7,113	7,675	8,113

Energy generation is assumed to remain at current levels in all scenarios - Table 5. For IE this means an average of 585.72MWh/month. The average monthly generation levels since 2013 have fluctuated but have not significantly improved (see Figure 7). Our ability to deliver this plan is dependent on the energy allocation in the MYTO 2019 Tariff Order.

Figure 7: Energy sent out by Gencos from January 2013 to July 2019



If future generation rises above this level, it can be considered in future major tariff reviews. However, while it seems more appropriate to base this performance improvement plan on historic expectation(see Figure 7), we planning with MYTO projections that have been provided by the regulator.

4.3.2.2 *Generation capacity*

Although energy generation is assumed to be constant, generation capacity is assumed to increase from January 2020, as PPAs will be activated. This means that Gencos who currently do not have active PPAs will be able to charge for their capacity that is available but not used.

- **Generation capacity charges for those Gencos with active PPAs in 2019** (Omotosho, Olorunsogo, Agip, Shell and Azura): Capacity charges were calculated based on the average capacity factor for each Genco in the months January to May 2019. These are 66%, 84%, 28%, 43% and 64% respectively.
- **Generation capacity charges for those Gencos without active PPAs in 2019:** Using data on the daily energy sent out from stations and the daily available capacity from the TCN daily operational reports from the start of 2013 to the end of May 2019, an average capacity factor of 54% was calculated. The average monthly energy in MWhs and the capacity factor of 54% was used to project the capacity charges expected from the remaining Gencos once their PPAs are activated in 2020.

The expected energy and capacity levels to be borne by Discos are shown in Table 44.

4.4 Outputs: strategic objectives

4.4.1 Performance Agreement

Our initial performance agreements are captured in Table 6.

Table 6: Performance Agreement metrics

No.	Key performance index	Measurement criteria defined in privatisation	Annual Performance					
			Base line	Y1	Y2	Y3	Y4	Y5
1	Loss reduction	ATC&C (%)	44.98 (2013)	32.9	28.0	20.8	15.2	10.8
2	Reliability/ availability	Frequency of system interruptions	N/A	100	50	25	10	2
3	Reliability/ availability	Duration of system interruptions	N/A	400	100	10	3	1.5
4	Metering	Number of new consumer meters installed	N/A	975	975	975	975	780

No.	Key performance index	Measurement criteria defined in privatisation	Annual Performance					
			Base line	Y1	Y2	Y3	Y4	Y5
5	New connection/ network expansion	Number of new customer connections	N/A	87871	101046	116198	133623	153661

4.4.2 Current service deficits

Since handover, Ikeja Electric has consistently delivered strong operational and business performance supported by a comprehensive operational framework that aligns overall business strategy and delivery with our KPIs. Despite the challenges of our operational environment and headwinds occasioned by the slow economic growth trajectory since takeover, Ikeja Electric has leveraged technology, teamwork and accountability to drive efficiency through innovation. Despite the enormity of the challenges, Ikeja Electric has not lost sight of its role as a provider of critical service, fomenting our desire to surmount all challenges. Our achievements are documented in Table 7.

With ATC&C loss reduction being the Nigeria Electricity Supply Industry (NESI) key objective, Ikeja Electric has executed a resolute strategy to significantly reduce the losses experienced in our business. Despite the ATC&C baseline study in 2014 at privatization under-representing true loss levels (39-42% submitted by Ikeja Electric vs 33% adopted by NERC), Ikeja Electric has employed innovative strategies to progressively reduce losses. Some of these initiatives include

- Metering of all trading points, from feeders all the way to distribution transformers, to ensure proper energy accounting
- Installation of distribution transformer meters for accurate energy accounting and to improve the Estimated Billing methodology.
- Ongoing enumeration and mapping of customer to network assets with the objective of improving the integrity of our customer database.
- Increased energy vigilance and surveillance activities to guard against energy theft and identify free riders for possible energy recovery
- The introduction of the Meter Reading Application across the network to enhance the reliability of customer meter readings
- Continuous installation and recertification of meters.

These initiatives have enabled Ikeja Electric achieve a 21% reduction in ATC&C from 32.9% at hand-over to the current value of 26%. Our commitment to improved power supply reliability and equipment availability through optimised investments and technology interventions to

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reduce equipment failures, has seen the number of customer interruptions reduce by 72% from 29,342 at handover, to the current level of 8,133. Our efforts to improve access to energy in Lagos state, has seen a total number of 383,307 new customer connections since handover, supported by an average annual increase of 11%. The regulatory directive on customer metering has witnessed significant changes since takeover from the Credited Advanced Payment for Metering Implementation (CAPMI) scheme, to the MAP regulation in 2018. Despite the uncertainties on this front, Ikeja Electric has successfully deployed 130,641 customer meters since handover while there remains a metering gap of 67%. With our company mission and safety vision of zero fatalities, our commitment to the safety within our service area has seen a 81% reduction in third party related deaths, from 16 in 2013 to 3 in 2019, and an 80% reduction in employee fatalities, from 5 in 2013, to 1 in 2019.

Ultimately the challenges being experienced by Ikeja Electric, including low collection from non-maximum demand customers due to inadequate metering, unpaid MDA debts, energy misallocation by TCN and a significant mismatch between our actual ATC&C at handover and the baseline studies, have impacted our ability to pay our full market bills. With the required regulatory support and our innovative approach to achieving maximum operational efficiency, this should see us meet our full market obligations in the future.

Table 7: Current service levels

No.	Key performance index	Measurement criteria defined in privatisation	Annual Performance		
			2013 (handover)	2018	Six months to June 2019
1	Loss reduction	ATC&C (%)	32.9	31.4	26
2	Reliability/availability	Number of customer Interruptions (#)	29,342	10,845	8,133
3	Metering	Number of new consumer meters installed	10,550	22,248	32,295
4	New connection/ network expansion	Number of new customer connections	38,840	58,338	25,724
5	Customer satisfaction	Customer feedback	96	92	85
6	Safety	Number of deaths	Employee-5 3^{rd}-Party - 16	Employee-2 3^{rd}-Party -6	Employee-1 3^{rd}-Party -3
7	Social responsibility	Number of Community outreaches per year	0	4	2
8	Remittance	Market remittance to NBET and MO (%)	NBET – 0 MO - 0	NBET – 40 MO - 59	NBET- 35 MO - 79

4.4.3 Goals 2020-2024

Target outputs are dependent on the modelling scenario, on tariff levels and allowed CAPEX. The target outputs assume all the allowed CAPEX is spent in each scenario. If financing is insufficient to meet the required CAPEX, the achievable outputs may differ from the target outputs documented in this plan. Other challenges which may impact our ability to deliver our goals is our adverse business environment discussed in Section 8.

4.4.3.1 *Target outputs in "no intervention" scenario*

A business as usual scenario called "no intervention" based on NERC tariff assumptions from the latest minor review (June 2019), which treated the end of 2020 as year 4 of ATC&C loss reduction.

We expect the constraints on our allowable CAPEX to limit our key performance indicator (KPI) outputs over the next five years, documented in Table 8. Our ATC&C trajectory defined in this scenario aligns with our current reality. The baseline figure of 15.2% for 2019 in the MYTO Minor Review Model is lower than the current level of 26%, hence we have made an incremental adjustment to the 2020-year end figure (20.0%) to reflect reality. We then expect to drive our losses from 20.0% in 2020 by 42%, to 11.6% by 2024. While this figure is higher than MYTO expectations, the disparity between our true ATC&C figure at privatisation and the figure from the baseline study means the ATC&C loss trajectory in MYTO is aggressive and not in line with reality for Ikeja Electric. The ATC&C figure of 11.6% in 2024, would see Ikeja Electric having achieved an overall loss reduction of 65% in ten years, from 32.9% in 2014, which is comparable to [1]Tata's 81% ATC&C reduction in Northern Delhi, a network within the Delhi state of India, over a 17-year period.

Table 8: Target service levels ("outputs") in "no intervention" scenario

No.	KPI	Measurement criteria defined in privatisation	Annual Performance					
			Base line	2020	2021	2022	2023	2024
1	Loss reduction	ATC&C (%)	15.2	20.0	20.0	13.7	12.4	11.6
2	Reliability/ availability	Number of customer Interruptions (#)	10,845	9,761	8,784	7,906	7,115	6,404

[1] https://blogs.worldbank.org/ppps/power-public-private-partnerships-turn-around-dysfunctional-utilities-case-tata-power-delhi

No.	KPI	Measurement criteria defined in privatisation	Annual Performance					
			Base line	2020	2021	2022	2023	2024
3	Metering	Number of new consumer meters installed	10,550	420,000	367,199	141,212	146,000	146,000
4	New connection/ network expansion	Number of new customer connections	38,840	54,750	157,000	137,699	52,954	52,954
5	Customer Resolution (%)	Customer feedback	85	85	86	86	87	89
6	Safety	Number of deaths and number of accidents	0	0	0	0	0	0
7	Social responsibility	Number of Community outreaches per year	4	4	4	4	4	4
8	Remittance	Market remittance to NBET (%) and MO (%)	NBET – 35 MO - 79	100	100	100	100	100

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We plan to ensure optimal availability and reliability of our operating assets to guarantee minimal power supply interruptions to our customers. However, supply constraints due current grid energy supply and infrastructure limitations (section 4.3.2), will limit our ability to guarantee a 100% reliability hence we intend to reduce customer interruptions by 10% year-on-year to achieve a figure of 6,404 by 2024. Our metering projections, based on our MAP initiative discussed in section 6.4, will see meters deployed for all currently unmetered customers, new customers and for replacements. Our projected customer growth plan of over 400,000 customers by 2024 accounts for new meter installations in our MAP plan. For our customer resolution, we expect metering related complaints to increase within the first 2 years as Estimated Billing Methodology related complaints reduce. Our corporate mission and safety strategy over the next five years is for zero death and accidents.

Our core business impacts and actively promotes the achievement of SDG 7 which is to ensure access to affordable, reliable and sustainable modern energy. In line with this objective, we intend to have one corporate social responsibility (CSR) engagement per quarter over the next five years.

4.4.3.2 *Target outputs in "with intervention" scenario*

The "with intervention" scenario based on a cost-reflective tariff, which recognises that tariffs have not permitted loss reduction to date (end of 2020 is treated as year 1 of ATC&C loss reduction) and allowing full required CAPEX to achieve the Disco's ambitious loss reduction and other output targets.

The outputs of the "with intervention" scenario differ from those of the "no intervention" scenario for only two KPIs, ATC&C and the number of customer interruptions. With Ikeja Electric unconstrained by CAPEX limits, and with NESI indicators attracting the requisite appetite from investors guaranteeing full financing for our investment plan, our innovative approach to loss reduction driven by technology investments should see us reduce losses from 21.3% at the end of 2019, to 8.8% by 2024. The ATC&C figure of 8.8% in 2024, would see Ikeja Electric having achieved an overall loss reduction of 73% in ten years, from 32.9% in 2014. We intend to achieve the 8.8% target one year later (2022) than our MYTO target (2021) due to the challenge of our baseline ATC&C level discussed above.

For our customer interruptions, we intend to achieve a 20% year-on-year reduction, to achieve a level of 3,554 by 2024.

Table 9: Target service levels ("outputs") in "with intervention" full CAPEX allowance scenario

No.	KPI	Measurement criteria defined in privatisation	Annual Performance					
			Base line	2020	2021	2022	2023	2024
1	Loss reduction	ATC&C (%)	21.3	15.9	10.8	8.8	8.8	8.8
2	Reliability/ availability	Number of customer Interruptions (#)	10,845	8,676	6,941	5,553	4,442	3,554
3	Metering	Number of new consumer meters installed	10,550	420,000	367,199	141,212	146,000	146,000
4	New connection / network expansion	Number of new customer connections	38,840	54,750	157,000	137,699	52,954	52,954

No.	KPI	Measurement criteria defined in privatisation	Annual Performance					
			Base line	2020	2021	2022	2023	2024
5	Customer satisfaction	Customer Resolution (%)	85.0	85	87	90	92	95
6	Safety	Number of deaths and number of accidents	0	0	0	0	0	0
7	Social responsibility	Number of Community outreaches per year	4	4	4	4	4	4
8	Remittance	Market remittance to NBET and MO (%)	NBET – 35 MO - 79	100	100	100	100	100

4.4.4 Projected investment

In the "no intervention" scenario, we assume Disco CAPEX is limited by levels allowed in MYTO.

In the final two "with intervention" scenarios (cost reflective tariff with unconstrained CAPEX), we NERC will allow the full CAPEX levels we propose in MYTO for 2020-2024.

Table 10: Assumed CAPEX constraints in MYTO

Naira billion	2020	2021	2022	2023	2024
Allowed in MYTO Minor Review (June19	15.2	15.2	18.9	18.9	18.9
Projected in this PIP (full proposed CAPEX without constraint)	18.7	38.6	19.2	19.2	19.2

4.4.5 Justification for Ikeja Electric's goals

- Performance Agreement commitments: In developing our goals, we have measured our current performance against our initial performance agreement commitments and have identified challenges that hindered our attainments of those commitments. We have also identified key success factors in areas where we have made significant

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progress. Our challenge and success evaluation have informed our proposed strategy, required processes, risk mitigation approach and investment requirements needed to achieve our goals over the next five years.

- Stakeholder response to consultation: The feedback from our stakeholders has been the key input into developing this plan. Our aim is to deliver efficient services that meet out stakeholder expectations and this has been achieved by prioritizing our stakeholder feedback in our plan. Customer satisfaction improvement, 100% metering and zero safety incident targets are some of the goals we have set in line with our stakeholder feedback. Feedback from our stakeholder engagement is captured in Annex A.

- Disco's ability to raise finance for the plan: Due to current NESI's illiquidity, the ability of Discos to raise finance is significantly constrained. Our ability to deliver our goals may be affected by our inability to raise the required finance to execute this performance plan. Our intention for the PIP is to access the power and aviation fund of the FGN via the Bank of Industry. We also intend to utilise the Nigeria Electrification Roadmap infrastructure support facility, berthed from a collaboration between the FGN and German government. Our financing plan is discussed in more detail in Section **Error! Reference source not found.**.

- Power Sector and Nation's growth: The Sustainable Energy for All Agenda of the federal government of Nigeria (FGN) targets 30GW of on-grid supply by 2030 supplied from renewable energy generation. In line with this ambition, Ikeja Electric's network expansion has been planned with adequate capacity to distribute the projected growth in energy supply. Additionally, with Lagos serving as one of the key commercial hubs in Africa, Ikeja Electric aims to efficiently and reliably supply the power to drive its economic growth and development.

4.5 Challenges

The economic environment has continued to present challenges to the financial stability of the electricity industry. As has been the case since the handover, Ikeja Electric has continued to struggle with lack of a cost-reflective end-user tariff. Required significant changes to input factors in the Multi- Year Tariff Order (MYTO) 2015 were delayed until the July 2019 MYTO Tariff Order, due to the lack of minor tariff review implementation within the period. This delay constrained our ability to raise adequate finance and was an inducing factor for NESI's illiquidity. Some assumptions including projected generation levels and exchange rate, in the MYTO 2019 still do not reflect reality. While other players in the sector are able to pass costs down the value chain to the distribution companies, the delay to review the tariff in accordance with set mechanisms and industry agreements has meant that distribution companies, such as Ikeja Electric, have been unable to pass these costs to consumers. This means that distribution companies will continue to sell electricity at a significant loss, in the interim.

The declaration of eligible customers in 2017, before the attainment of a fully competitive NESI has led to the attrition of maximum demand customers, designed in MYTO to cross subsidize the tariffs of non-maximum demand customers. The declaration of this regulation has further worsened the liquidity position of Discos due to shortfalls realized from the reallocated energy.

Energy theft constitutes another serious challenge to the profitable running of the electricity industry. Many households indulge in different forms of electricity theft and illegal tampering of electric metering devices. These lead to distribution system faults and overload as well as loss of revenue by the distribution companies. Customer apathy to payments and of concern is the ongoing reluctance of government ministries, departments and agencies (MDA's) to pay for their energy consumption and settle outstanding obligations which has contributed to the liquidity crisis in the sector. Inflation rate, exchange rate, etc. are all major challenges to efficient running of a financially sustainable electricity distribution system. Despite the enormity of the challenges we face, we will never lose sight of the fact that as a provider of a critical service, we must be committed to intensifying our efforts in surmounting all challenges.

Our performance plan includes a risk evaluation in Section 8 that discusses our business challenges in more detail.

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5 Infrastructure Review

5.1 Overview

This section covers:

- Current state of infrastructure;
- Review of current limitations;
- Need for area strategies;
- Recent and ongoing projects; and
- Implications of the infrastructure review.

Each section of the plan should have an overview and contents page.

5.2 Current state of infrastructure

Ikeja Electric (IE) serves eight local major Local Government Areas in Lagos state, Nigeria; Alimosho, Agege, Ifako-Ijaye, Kosofe, Ikorodu, Oshodi-Isolo, Shomolu, and Ikeja, while others like Amuwo Odofin, Epe, Mushin, and Lagos Mainland are shared with Eko Electricity Distribution Company. IE also serves three Local Government Areas, under the franchise area of Ibadan Electricity Distribution Company, in Ogun state. The distribution network, operated at three voltage levels, serves major residential, commercial and industrial hubs within the state, covering six business units within its network. There are 89 - 33kV feeders, 281 - 11kV feeders, and 17,714 distribution transformers – see Table 11.

Table 11: Ikeja Electric Distribution Network

s/n	Distribution Network	Number
1.	Business Units (BU)	6
2.	33kV feeders	89
3.	11kV feeders	281
4.	Distribution Transformers	17,714

The IE single line diagram (SLD) shows the network configuration and the flow of energy from Transmission Company of Nigeria (TCN) stations to 33kV feeders, to injection substations and then to 11kV feeders as shown in Figure 8.

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The IE network is supplied from 17 TCN transmission stations with a combined nameplate capacity of 2,620MVA, with 2,375MVA supplying IE. The 89 33kV feeders, comprising 21 underground and 68 overhead feeders, supply 155 (73 public and 82 private) 33/11kV power transformers across 113 injection substations. With a total 33/11kV power transformer transformation capacity of 2,053MVA, 281 11kV feeders are energized for onward downstream power distribution.

There are 16,412 11/0.415kV distribution transformers and 1,302 33/0.415kV distribution transformers served by IE. The total transformational capacity of the 11/0.415kV and the 33/0.415kV distribution transformers are 3,499.9MVA and 991.9MVA respectively – see Table 12. The route length for the 33kV, 11kV, and 415V feeders are 1,642.3km, 2,496.6km, and 5,927.4km respectively, resulting in a total route length of 10,065.2km.

Table 12: Ikeja Electric Network Configuration

S/N	Network Parameters	Unit	Total
1.	Transmission Substations	No	17
2.	132/33kV transformers	No	44
3.	Injection Substation	No	73
4.	33/11KV Transformers	No	155
5.	33/0.415kV Transformers	No	1,302
6.	11/0.415kV Transformers	No	16,412
7.	Installed Transmission Capacity	MVA	2,620
8.	Installed Transformer Capacity (33/11kV)	MVA	2,053
9.	Installed Transformer Capacity (33/0.415kV)	MVA	991.9
10.	Installed Transformer Capacity (11/0.415 kV)	MVA	3499.7
11.	Route Length 33KV Feeders	ckt km	984.2
12.	Route Length 11KV Feeders	ckt km	2,266.4
13.	Route Length 415V Feeders	ckt km	5,599.8

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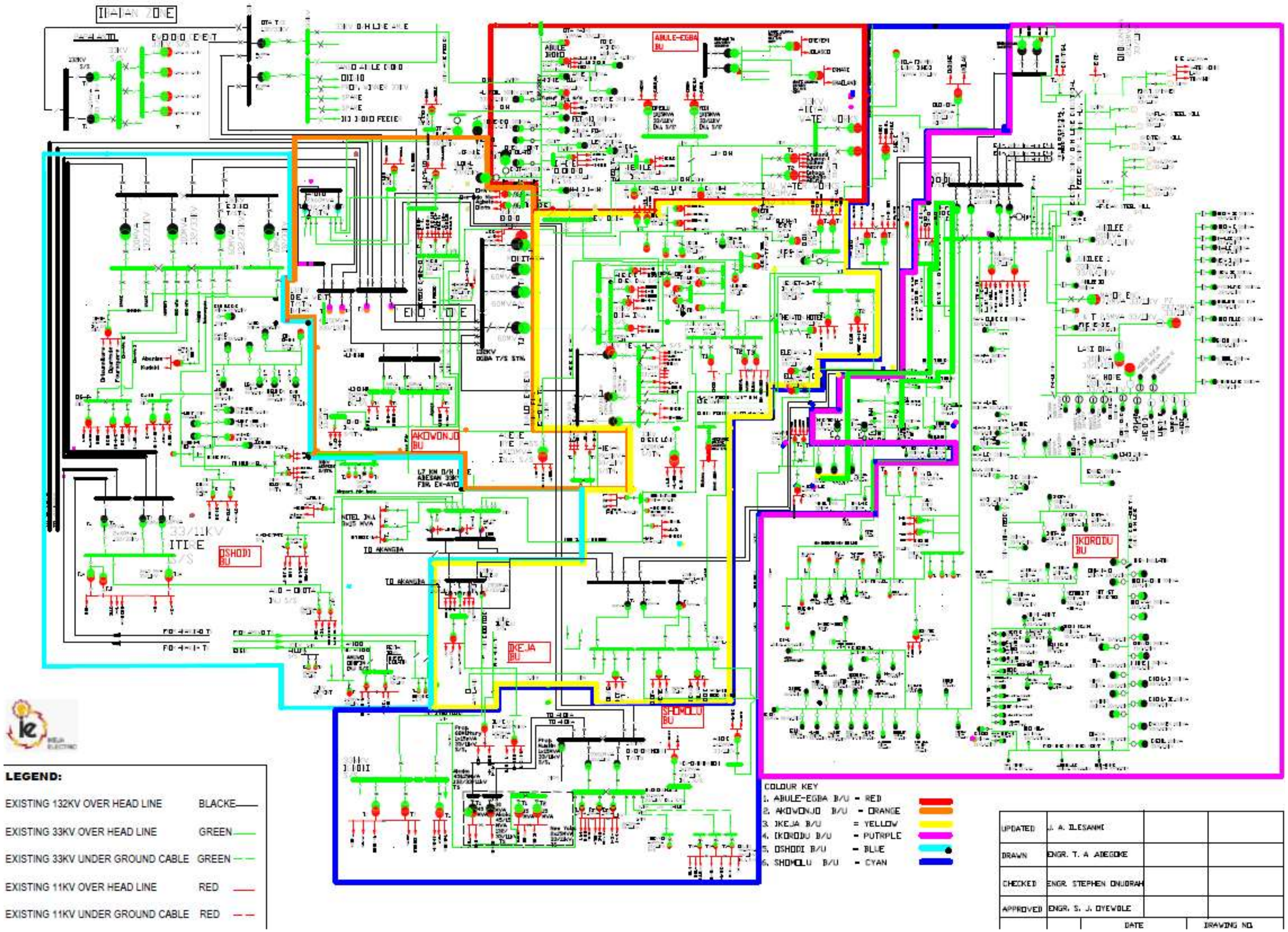
Figure 8: Ikeja Electric Single Line Diagram



Refer to to Annex I for regulatory asset inventory.

5.3 Review of current limitations

Infrastructure links primarily to the following targets:

- Reduce ATC&C losses from the current level of 26.0% to 8.8%, which will allow our business to be sustainable;
- Reduce the number of customer interruptions from the current level of 10,845 per year to 3,554 per year, increasing reliability for our customers;
- Increase the number of new customer connections from the current level of 54,750 per year to 52,954 per year.

5.3.1 Technical network constraints

This analysis uses the demand forecast discussed in section 4.3.1. Tables of the network constraints analysis are provided in Annex J.

5.3.1.1 *11kV Feeders Load Analysis*

Table 49 in Annex J. 1 shows the loading analysis of 11kV feeders. The line loading reveals the ratio of the constrained demand (peak demand) to the current rating of the feeder. The 2019 base year reveals 166 feeders of IE's 281 feeders being constrained, representing 59% of the 11kV feeders. The five most constrained feeders in 2019 are Isoto, Jakande 1, Igando- General Hospital, Isheri Oshun and Ijegun. By 2024, constrained feeders are expected to grow to 227 feeders, representing 81% of the 11kV feeders, if no investments are made. In 2024, without any investments, the five most constrained feeders are expected to be Bada, Opeilu, Governor, Abaranje and Centex.

Table 50 in Annex J. 1 shows the 11kV transformation capacity analysis and highlights the feeders where additional transformation capacity is required to prevent overloads on the network's distribution transformers. With a combined transformation capacity of 3,500MVA, for operational and efficiency reasons, IE sets a loading tolerance of 80% on its distribution transformers. Based on this loading tolerance, the 2019 base year reveals 10 feeders requiring additional transformation capacity and rising to 43 feeders in 2024 if no investments are made. The total transformation capacity required to decongest the distribution transformers in 2019 is 41.5MVA, with an additional 94MVA required by 2024 if no investments are made. The five most constrained feeders with limited transformation capacity include Post Office, Liasu, Apena, Ekoro and NAF.

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5.3.1.2 *33kV Backbone System Unconstrained Analysis*

The loading analysis of the injection substations (ISS) supplied by Ikeja Electric are captured in Table 51 in Annex J. 2 for the base year, 2019 and final year, 2024. The 33/11kV power transformer loading analysis is based on IE's network planning criteria of a maximum of 3 transformers at any injection substation. If any transformer is overloaded and there are less than 3 transformers at its injection substation, then an upgrade for an additional transformer is recommended. However, where there are 3 transformers at an injection substation, and it is overloaded, it is recommended that a new injection substation is be built on the 33kV feeder connected to the current injection substation.

In the 2019 demand analysis, 60 transformers are recorded in the network to be overloaded (at 80% loading tolerance), however due to the network planning limit of three power transformers per injection substation, only 39 (38 1X15MVA and one 1X7.5MVA) transformers can be accommodated at existing injection substations to relieve overloaded transformers, which leaves 21 overloaded transformers. In order to fully decongest all overloaded 33/11kV power transformers, 11 new injection substations are required to accommodate 21 (21 1X15MVA) transformers – see Table 52 in Annex J. 2. The five most constrained 33/11kV transformers include Ilapo 1X2.5MVA, Ekoro 1X15MVA T1, Sabo 1X15MVA T2, Iju 1X15MVA T1, and Sabo 1X15MVA T2

In the 2024 loading analysis if no investments are made, it is observed that the demand growth to be experienced in the network will result in overloads in 92 transformers across IE injection substations. Due to the network planning transformer per injection substation limit highlighted above, only 60 (59 1x15MVA and one 1X7.5MVA) transformers can be accommodated at existing injection substations to relieve overloaded transformers. In order to fully decongest all overloaded 33/11kV power transformers, 13 new injection substations are required to accommodate 32(32 1x15MVA) transformers – see Table 52 in Annex J. 2.

5.3.1.3 *33kV Feeders Load Analysis*

Table 53 in Annex J. 2 shows the loading analysis of the 33kV feeders and the amount in MVA each feeder is overloaded by. With an assumed capacity of 26.2 MVA for each feeder, in the 2019 load analysis, 22 of the 89 33kV (25%) feeders are overloaded, the most significant of which is Egbe 33kV feeder by 40 MVA. Other highly constrained feeders include Owutu, Amje, Igbogbo 33kV and Abeokuta Express 33kV. The total feeder exceedance in 2019 is 199.7 MVA. By 2024, it is expected that the number of overloaded feeders increases to 46 (51%), if no investments are made, with a total feeder exceedance of 865.5 MVA. In 2024, the most constrained feeders are expected to be Egbe, Amje, New Iju, Owutu and Bolorunpelu.

5.3.1.4 *Projected Load by TCN Station*

The forecasting methodology applied in this study was performed at the 11kV and 33kV feeder level, thereby generating a demand forecast for each feeder. A summary of the 33kV demand forecast and the TCN substation demand forecast are presented in this report. The projected load summarised at TCN substation level is presented in Table 54 in Annex J. 3 and graphically shown in Figure 9.

While the total nameplate capacity across the TCN stations supplying IE is 2375MVA (excluding 60MVA from Ojo), however, the total transformer capability, i.e., the total loading allowed on the transformers, is 1,675 MW. With the 2019 unconstrained peak demand of 1,444 MW, the current TCN operational capacity is adequate to supply IE power, however, the disaggregate values of peak demand downstream the TCN stations reveal this operational capacity is insufficient. Across the 17 TCN stations that supply the IE franchise, by nameplate, there is adequate capacity to meet the peak demand in 2019 in 16 stations, however, this reduces to 5 by 2024. However, by transformer capability, there is capacity to meet demand in 13stations in 2019, and this reduces to 4 by 2024 if no TCN investments are made.

Some specific examples are discussed in Box 1.

Box 1: TCN substation capacity – discussion of specific examples

Ikorodu TCN substation has the current highest peak demand of 276 MW	Demand expected to increase to 371 MW by 2024. While IE has a distribution transformer capacity of 712 MVA to serve this demand, the Ikorodu TCN station with a nameplate capacity of 280MVA, has a transformer capability limit of 201MW. The capability limit at the Ikorodu TCN station causes downstream supply constraints as 75MW of current peak demand cannot be served.
The largest percentage increase in demand over the period occurs at the Alausa TCN station, with a 114% increase	Increase from 102MW to 219MW.This increase is based on a 91% increase in customers from 51,232 to 98,027. The total current distribution transformation capacity connected to Alausa TCN station is 375MVA, comprising 1,294 11kV/415V transformers, and 2033kV/415 transformers, however, the Alausa TCN station with a nameplate capacity of 135MVA, has a transformer capability limit of 86MW.
Only Isolo TCN stations have more capacity than downstream distribution.	Only the Isolo TCN station with a capacity of 165 MVA, has more capacity than its downstream connected distribution transformation capacity (147 MVA).

The projected constrained TCN stations using transformer operational capacity are Alausa, Ikorodu, Itire ,and Maryland in 2019, and in 2024 without any investments, the additional stations are Alimosho, Amuwo, Ayobo, Ejigbo, Ilupeju, Ogba, Oke-Aro, Otta and Oworo – see Figure 10. Currently, constraints are being experienced at the Ogba Station.

Currently IE shares 4 TCN stations with EKEDC (Akoka, Amuwo, Itire, and Ojo) and 1 TCN station with IBEDC (Otta), hence the demand projection impact on these TCN stations are limited to IE load only. The analysis does not include the 132kV eligible customer demand.

Figure 9: Load Forecast by TCN Stations

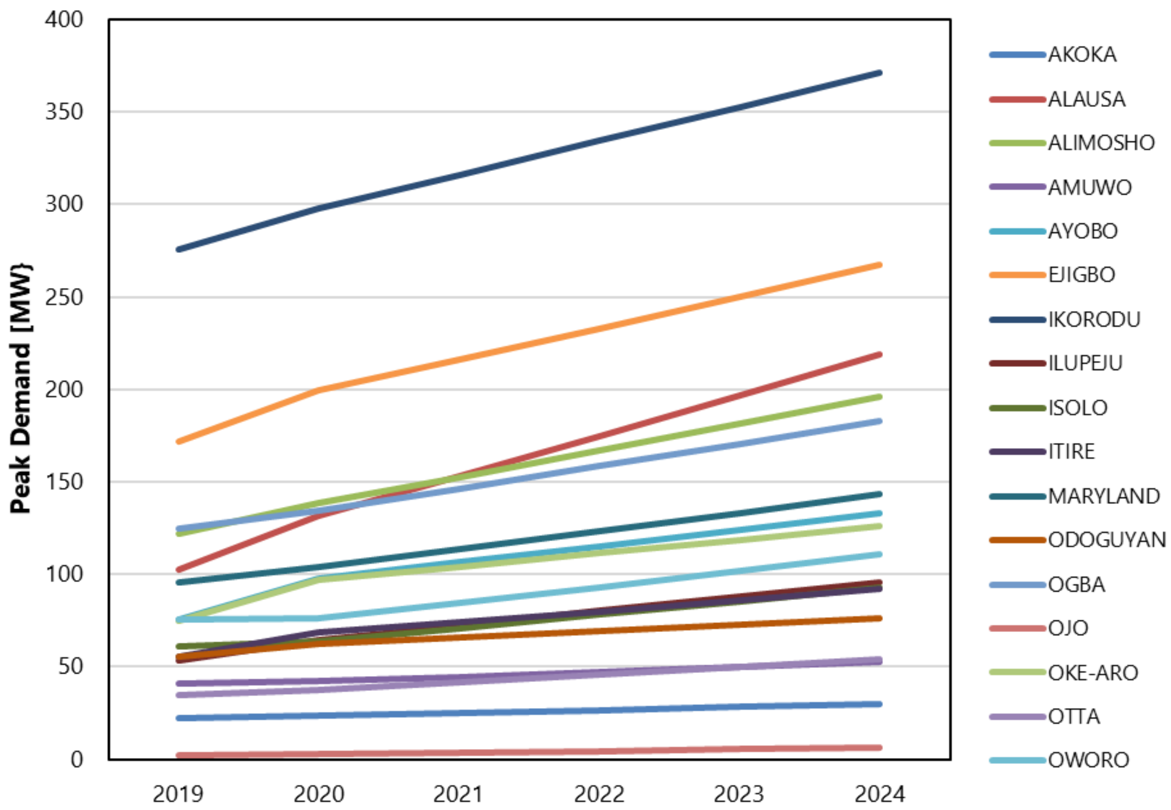
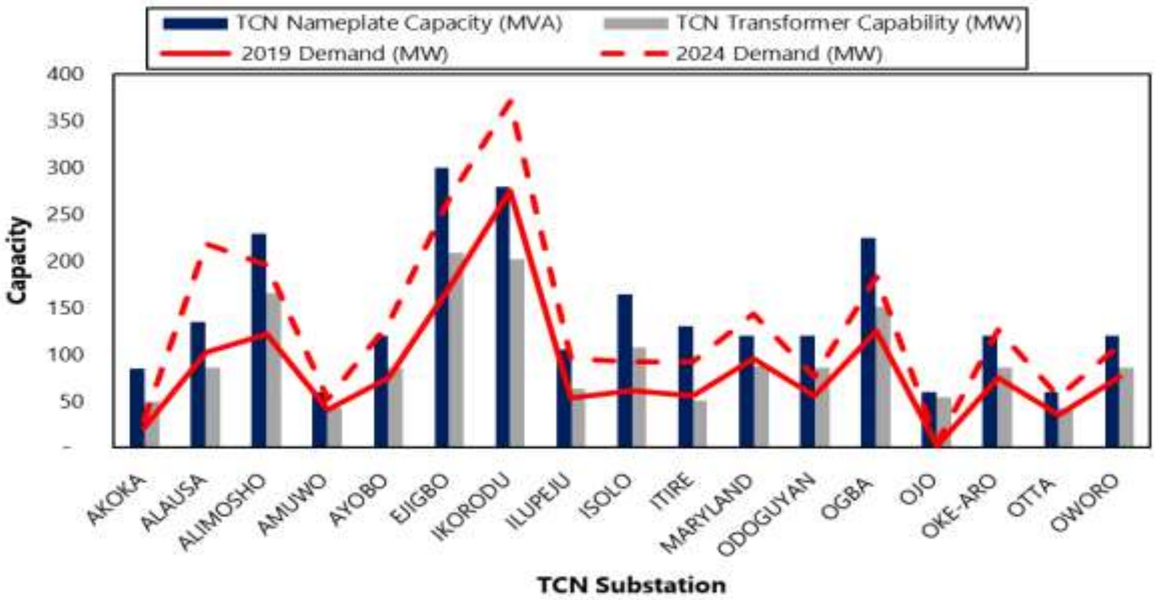


Figure 10: Demand Forecast (2019 & 2024) and TCN Station Capacity



5.3.2 Aging infrastructure

The reliability of electrical power supply is amongst the conditions that inform aging analysis at Ikeja Electric. Reliability depends both on the condition of the distribution infrastructure and the quality of energy supplied. Its value to customers may be capitalised into the value of the company.

We use an aging analysis approach, comparing initial cost of purchase to its net book value to test the reliability offered by distribution infrastructure and the asset replacement requirements.

Below is a summary in Figure 11 showing the total sum of costs of our assets, with the net book value at the end of 2018, and the projected useful life. Ikeja Electric performed an asset revaluation exercise in 2018 to reflect the actual performance of acquisition assets in our regulatory asset base. The total revalidated sum of costs was N280billion, with a 98% contribution from plant and machinery (N274billion). At the end of 2018, the net book value of our assets was N115billion. In five years, we project a net book value of N86billion and with a need for asset replacement over the next five years to maintain an average useful life that guarantees reliability.

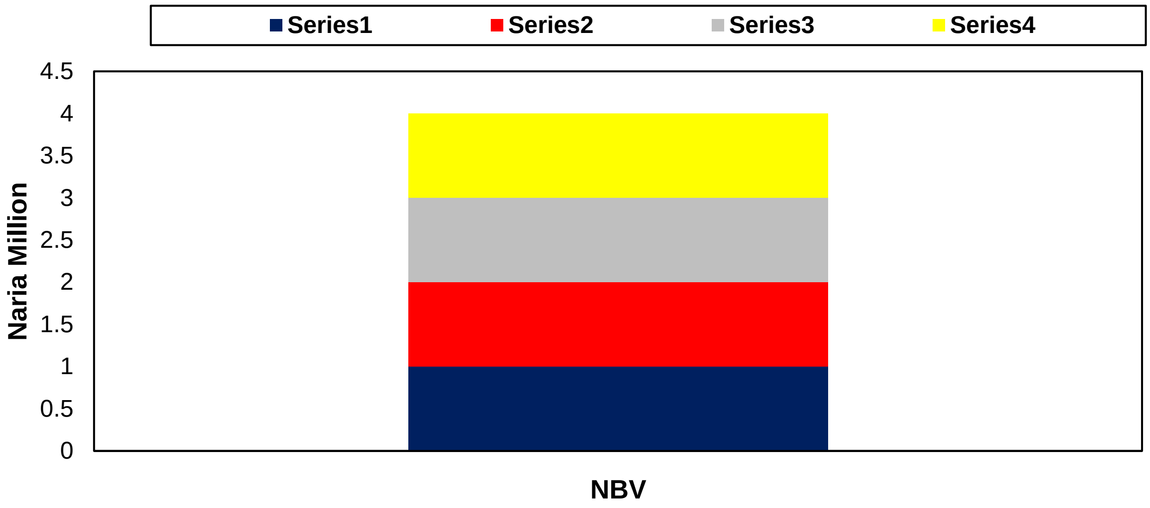


Figure 11: Ageing Infrastructure Analysis

5.3.3 Customer enumeration analysis

Customer enumeration is being achieved through the MAP know your customer process. Table 13 below shows our enumeration and metering requirement status by Business Unit as at January 2019.

Table 13: Customer Enumeration Status

Business Unit	Unmetered Customers		Total Unmetered Customers	New Customers / Replacement	Total Population
	Single Phase	Three Phase			
ABULE-EGBA	67,663	44,185	111,848	67,109	178,957
AKOWONJO	96,977	39,876	136,853	82,112	218,965
IKEJA	15,835	14,589	30,424	18,254	48,678
IKORODU	136,041	36,896	172,937	103,762	276,699
OSHODI	61,526	87,515	149,041	89,425	238,466
SHOMOLU	4,408	65,996	70,404	42,242	112,646
Total	**382,450**	**289,057**	**671,507**	**402,904**	**1,074,411**

We currently have 671,507 unmetered customers and an effective metering gap of 67%. The metering gap poses a significant challenge in reducing our collection losses as a result of a lower willingness by unmetered customers to pay bills using the Estimated Billing Methodology. Ikeja Electric has engaged the services of three MAP providers to close this gap by 2022 – see section 6.4.

5.3.4 Metering gaps

Table 14 provides a metering gap analysis, including both meters to be provided by IE and those to be provided by MAPs.

Table 14: Review of metering gaps

Metering	Priority assigned by NERC in PIP Guidelines	Current situation	IE desired implementation date
Bulk metering (market interface)	Very high priority	The Market Operator has always insisted that the Chinese-made CLOU meters deployed by IE are not acceptable because Chinese meters are not acceptable in the settlement market and therefore have never been accepted as check meters to the main meter. Metering of proposed 33kV feeders to be radiated at the rate of 3 feeder meters yearly in alignment with Technical projection. Metering of proposed 11kV feeders to be radiated at the rate of 3 Incomer meters and 7 feeder meters yearly in alignment with Technical projection. (2 outgoing feeder meters to 1 incomer meter). 3 dedicated 132/33 kV TS; all are metered with EDMI type, cl 0.2s meters. 41 incomers; all are metered with EDMI type, cl 0.2s meters. 89 33kV outgoing feeders; all are metered with CLOU type, cl 0.5s meters. 17 11kV feeders at trading points 16 have CLOU type, cl 0.5s meters while 1 feeder (shared with EKEDC) has ITRON type, cl 0.5s meter.	To procure and install around 120 class 0.2s meters with metering units by end 2024
MDA metering	Very high priority	To be metered: 21 active & suspended accounts, 10	Metering for unmetered MDAs

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Metering	Priority assigned by NERC in PIP Guidelines	Current situation	IE desired implementation date
		replacements and 23 inactive accounts	scheduled for June - August 2020. Metering procurement achieved through transparent and competitive process.
Revenue Protection Project (RPP) supported by Advanced Metering Infrastructure (AMI)	High priority	Ikeja currently has Metering Control Centres and AMI for high and medium voltage customers, and low voltage customers with monthly consumption above 1,000 kWh.	Intend to procure state-of-art Meter Data Management (MDM) software in 2020 at a competitive price. Platform design that would aggregate all current AMI platforms (Mojec, AMI etc). Module to be part of ERP suite when deployed.
Distribution transformer (DT) metering	Not assigned	Public – Ground Mounted: 172 yet to be metered and 480 for expected new DT to serve as relieve to overloaded DTs in the year 2020. Then 480 DTs yearly in the subsequent years. Public-HVDS: 2426 for yet to be connected and commissioned in the year 2020. Then 1000 HVDS in the subsequent years. The annual plan also includes the replacement of faulty DT meters – 5% of public DT meters and 10% of point load meters.	Public – Ground Mounted: Relief DTs by 2020. Thereafter, annual acquisition required for network and customer growth. Public – HVDS: Relief DTs by 2020. Thereafter, annual acquisition required for network and customer growth.
Customer metering (MAP)	Not assigned	333,633 customers metered (MD – 5,513 and Non-MD 328,120) representing 33% of customers. All customer enumeration/regularization is achieved by going	100% customer metering to be achieved by 2022 with implementation supported by 3 metering asset providers (MAP) –

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Metering	Priority assigned by NERC in PIP Guidelines	Current situation	IE desired implementation date
		through the MAP KYC process. IE has a customer metering gap of 1,074,411 meters including actual unmetered customers and replacements.	CIG, Mojec and New Hampshire.

5.3.5 IT gaps

Table 15 provides the status of all the management systems required by NERC and those identified by Ikeja Electric.

Table 15: Review of management system gaps

Management system	Priority assigned by NERC in PIP Guidelines	Current situation	IE desired implementation date
Incidents Recording and Management System (IRMS)	Very high priority	Based on logging customers call in to report outages and manual reports from dispatch.	2022
Commercial Management System (CMS)	High priority	Ikeja CMS currently has adequate functionality for Meter Reading, Billing, Service Anomalies, Billing Adjustment, Payments Processing, Service Application, Customer assistance and complaints and Energy Sales	Investment is required for Meter Management System and Meter Information System functionalities. Functionality to be added by 2020 and 2021 respectively. Procurement will be through a transparent and competitive process that guarantees cost efficiency.
Enterprise Resource Planning (ERP) information system	High priority	Currently have four different applications that manage the various areas of the business – Procurement Management System, HRMS, Sage Financials	Plan to procure an ERP solution that encompasses all the four modules defined by NERC. Procurement will be through a transparent and competitive process

Management system	Priority assigned by NERC in PIP Guidelines	Current situation	IE desired implementation date
		and Legend Inventory Management System	that guarantees cost efficiency.
Geographical Information System (GIS) mapping of customers and network assets	High priority	IE currently uses ArcGIS by Esri. Currently includes Customer and Asset Database and the capability to link customer to network and incorporate it into the IRMS.	Need to add Network Asset Database and reconcile to the on-going Customer Enumeration Exercise complete the functionality. An expert will be required to evaluate the scope and scale of the project including costs. Procurement will then be implemented through a transparent and competitive process that guarantees cost efficiency.
Supervisory Control and Data Acquisition System (SCADA)	High priority	Not currently in place.	Plan for phased implementation by 2024.
Works Management System (WMS)"	Medium priority	Isolated tools currently used are IE force, CRM, Mobi works. These tools are not integrated.	Integrated system to be purchased as a module within the ERP system. Procurement will be through a transparent and competitive process that guarantees cost efficiency.
Incidents Recording and Management System (IRMS)	Very high priority	Based on logging customers call in to report outages and manual reports from dispatch.	2022

5.4 Recent and ongoing projects

Some of the network infrastructure projects are currently ongoing include

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1) Proposed Ijegun and Igando 33kv double circuit ex- Ejigbo 2 x 100MVA + 60MVA + 40MVA 132/33kV T.S. Ijegun & Igando Undertaking, Oshodi Business Unit.

2) Proposed Oregun 33kV feeder ex Alausa T.S Oregun Undertaking, Ikeja Business Unit.

3) Proposed Obadore 11kV feeder ex - Igando 2 x 15MVA Injection S/S to relieve Akesan 11kVfeeder, Igando Undertaking, Oshodi Business Unit.

4) Proposed extension of Adiyan 11kV feeder from Pastor Oladimeji S/S to Itokin to relieve Ijoko road 11kV feeder. S/S. Adiyan Undertaking, Abule Egba Business Unit.

5) Replacement of Mangoro Injection S/S Panels

6) Proposed conversion of 2 33kV indoor breaker to outdoor at Ogudu Injection S/S.

5.5 Implications of the infrastructure review

There has been a prolonged period of underinvestment in the distribution networks in Nigeria. In November 2013, Ikeja Electric inherited networks from PHCN that had received minimal investment for many decades. In some cases, this was simply emergency investment to maintain supply, or expansion based on political rather than economic drivers. At handover, the distribution capacity was 1,684MVA, with an average daily supply of 9hours. The network assets were poorly metered, with minimal feeder and DT metering resulting in poor energy accounting. The network was dominated by undersized and over extended high- and low-tension lines supplying overloaded transformers. The network was ageing with non-resilient distribution network equipment.

Much investment is needed to turn Ikeja Electric into a modern distribution company.

In developing this PIP, Ikeja Electric has prioritised investment to best deliver the outputs given current liquidity constraints. The process for investment planning was discussed in section 3.5. The output goals are defined in section 4.4.

Resulting infrastructure investment plan is in section 6.

6 Detailed Program Plans

6.1 Overview

This section covers:

- Delivering outputs efficiently;
- Electricity distribution investments;
- Working with Meter Asset Providers (MAP);
- Commercial operations investments;
- Health and safety plans;
- Resourcing plans; and
- Overall investment plan.

Reference to **Error! Reference source not found.** for detailed breakdown

6.2 Delivering outputs efficiently

How the planning for each output delivers efficiently:

In order to efficiently deliver outputs in the PIP, we had to ensure that our internally prioritized initiatives were aligned with the feedback received from our stakeholders. The issues that were priority for our stakeholders bothered on metering and power supply availability/reliability which both coincide with our priority initiatives for investment.

Investing in improving the availability/reliability of power supply enable us increase revenues and recover our costs. Supporting the MAP metering exercise of our customers as well as investing in network metering infrastructure is top priority for us as we believe that it will greatly reduce commercial and collection losses within our network. Our investments in state-of-the-art technology will provide us the platform for real-time monitoring of our network performance and business operations which will allow us to perform efficiently. The planned acquisition of NEPLAN and SCADA will help us to better ascertain technical losses. Our optimisation model for network investments (OMNI) tool will be used to prioritise all network investments to ensure optimal use of available capital. Our planned training programmes will equip our workforce with the capacity required to deliver their KPIs efficiently. We will also keep engaging our stakeholders to identify their challenges to develop the required solutions for customer satisfaction.

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6.3 Electricity distribution investments

Linked to the following targets:

- Reduce ATC&C losses from the current level of 26.0% to 8.8%, which will allow our business to be sustainable;
- Reduce the number of customer interruptions from the current level of 10,845 in 2019 to 3,554 by 2024, increasing reliability for our customers;
- Increase the number of new customer connections from the current level of 63,749 per year between 2014 and 2018, to 100,601 per year between 2020 and 2024.

6.3.1 Network Investment Summary

Our five-year network investment plan summarised in Table 16, will see Ikeja Electric undertake projects to upgrade existing network capacity, invest in technological enhancements to reduce outages and system downtimes, acquire tools to analyse network performance and network assets that provide real-time visibility and performance data. The projected investment requirement over the five years is N101billion.

Table 16: Network Investment Plan

	Capex (N Billion)				
Network Investment Type	**2020**	**2021**	**2022**	**2023**	**2024**
Reliability, Distribution Automation	1	0.66	0.46	0.46	0.25
Planning and Construction (P&C)	12.25	10.13	16.50	19.01	21.92
Loss Reduction		0.5	-	-	-
Protection, Control & Metering (PC&M)	0.42	0.42	0.42	-	-
IT & Automation	0.08	0.05	-	-	-
Total	**13.75**	**11.76**	**17.37**	**19.74**	**22.17**

Our P&C projects involve the radiation of new 33kV feeders to increase primary distribution capacity from 1,740MVA to 2,000MVA. The radiation of new 11kV feeders to increase the network capacity from 1,360MVA to 1,610MVA. Construction of new injection substations and upgrading of existing substation capacity to increase injection substation capacity to 2402MVA. These projects will be complemented by the addition of 487 relief distribution transformers and the reconductoring of our low tension (LT) lines. Other initiatives include the replacement of faulty panels and switchgears at 27 injection substations, and the maintenance of 330km of overhead 11kV and 33kV feeders.

Our PC&M initiatives involve the acquisition of network improvement tools and machinery. For IT & Automation, our plan includes licenses for AutoCAD and NEPLAN to improve our load flow modelling and technical loss evaluation. Our loss reduction initiatives include the reconditioning of 50 power transformers to reduce variable energy losses. Our Reliability and Distribution Automation projects include distribution transformer remote monitoring module, installation of remote terminal units at injection substations and the procurement of fault indicators. The schedule of investments is presented in Annex E.

6.3.2 Incident Reporting System

Ikeja Electric currently uses a combination of logged customer complaints on CRM and manual logs from Dispatch to record network incidents. The challenge with this system is that not all customers call to log complaints thereby creating gaps in the data gathering process. To address this challenge and to reduce the dependency on human intervention, the ERP system to be procured will be enabled with a functionality for incident reporting. See section 6.5.5

6.3.3 Network metering plans

Ikeja Electric intends to purchase 11,499 meters over the next five years to improve monitoring and reconciliation of boundary point energy transactions, improve billing and collection efficiency, monitor energy sales across the network value chain and data gathering for demand forecasting and energy supply analysis. The required meters include 106 replacement meters for network feeders, 65 new meters for network feeders, 7,078 new distribution transformer meters, and 4,250 replacement meters for distribution transformer – Table 17.

Table 17: Network Metering Investment Plan

		Capex (Naira Million)				
Type of Meters	**Number**	**2020**	**2021**	**2022**	**2023**	**2024**
Replacement Feeder Meters (Cl 0.5s EDMI to replace Cl 0.5s CLOU)-33kV	89	22				

		Capex (Naira Million)				
Type of Meters	**Number**	**2020**	**2021**	**2022**	**2023**	**2024**
Replacement Feeder Meters (Cl 0.5s EDMI to replace Cl 0.5s CLOU)-11kV	17	4				
New Feeder Meters (Cl 0.5s EDMI)-33kV	15	1	1	1	1	1
New Feeder Meters (Cl 0.5s CLOU)-11kV	50	3	3	3	3	3
DT Meters (Public- Ground mounted)	172	69				
DT Meters (Public- Ground mounted)	480	192	192	192	192	192
DT Meters (Public-HVDS)	6,426	437	437	437	437	437
Replacement of public DT meters	2,250	180	180	180	180	180
Replacement of point load meters (LVMD customers)	2,000	160	160	160	160	160
Total	**11,499**	**3,087**	**2,993**	**2,994**	**2,995**	**2,996**

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In order to resolve market interface disputes with the MO on meter type deployed by IE, IE will need to procure network feeder meters that meet the MO's standard. The Market Operator (MO) has always insisted that the CLOU meters deployed by IE are not acceptable because of the product type, which the MO deems not acceptable in the settlement market, and therefore has never been accepted as a check meter to the main meter.

IE also intends to procure network meters for 33kV and 11kV feeders for new feeders annually. Metering of proposed 33kV feeders to be radiated at the rate of 3 feeder meters yearly in alignment with Technical projection. Metering of proposed 11kV feeders to be radiated at the rate of 3 Incomer meters and 7 feeder meters yearly in alignment with Technical projection. (2 outgoing feeder meters to 1 incomer meter).

For the distribution transformers, IE requires meters for existing unmetered transformers and replacements for faulty transformers. There are 172 distribution transformers yet to be metered and 480 for new distribution transformers to serve as relieve to overloaded transformers in the year 2020, and in the subsequent years. 2426 meters are also required for yet to be connected distribution transformers and those to be commissioned in the year 2020, with 1000 meters required in the subsequent years. Annually, 5% of public distribution transformer meters and 10% of point load meters are planned for replacement due to faults. Meter installations will be done by IE staff.

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6.3.4 New connections plans

New Connection Procedure

The procedure for a new customer to be connected is as follows. The customer is required to either visit any of our offices to pick up the NERC approved Meter application/New Connection request form or to download same on our website. This ensures that proper KYC is conducted on the customer's account and that the customer information is properly archived on our database.

The customer is advised alongside to register for metering via the MAP scheme to ensure all new connections are metered as stipulated by NERC.

The request is documented on the CRM and sent to the field account officers to confirm that the account doesn't already exist. If confirmed, the new account is generated, and the customer is informed of the account details. The customer is connected to the grid and metered under MAP scheme.

Existing Supply Address Procedure

If it is found that the supply address is not a new connection, the customer is informed that the address already has an electric account. However, if the customer wants separation of account on the same supply address, then the same procedure above applies.

These procedures will be implemented in line with our customer connection projections over the next years.

6.4 Working with Meter Asset Providers (MAP)

Linked to the following targets:

- Increase the number of new meters installed to an average of 268,728 per year till 2022, allowing customers to trust the bills they receive.

Table 18: MAP Rollout Plan

MAP Name	CIG	Mojec	New Hampshire	Total
Contracted Meters	397,922	399,790	276,699	1,074,411
Metering period (months)	36	36	34	36
Annual Target (Year)				
2019	47,000	49,000	49,500	145,500
2020	140,000	140,000	140,000	420,000
2021	140,000	140,000	87,199	367,199
2022	70,922	70,790	-	141,712

IE has a total metering gap of about 1,074,411 (Table 18), consisting of actual unmetered customers (671,507) and replacements (402,904). All customer enumeration and regularization are achieved through the MAP know-your-customer process. IE has contracted three Meter Asset Providers, CIG, Mojec and New Hampshire to deliver and install 397,922, 399,790 and 276,699 customer meters respectively over a 36-month period and to be completed by 2022.

Current Status

To take advantage of a phased deployment strategy that allows for early identification and mitigation of risks within a controlled environment while optimising customers experience, initial roll out was flagged off in Abule Egba Shomolu and Ikorodu Business units in May 2019. However, with effect from August 2019, MAP roll out has been extended to all business units with the onboarding of Akowonjo, Ikeja and Oshodi BUs. Our MAP to BU assignment is as follows

1) CIG: Abule Egba, Akowonjo
2) Mojec: Ikeja, Oshodi, Shomolu
3) New Hampshire: Ikorodu

Table 19: IE MAP Status

MAP	MAP Ready customers	Records Shared with MAP	Survey	Meter Payment	Installation	Run rate
CIG	22,129	22,129	3,393	3,229	1,691	**52%**
New Hampshire	13,390	13,390	4,825	512	392	**77%**
Mojec	25,832	25,832	4,762	1,836	1,393	**76%**
Total	**61,351**	**61,351**	**12,980**	**5,577**	**3,476**	**62%**

Table 19 shows our status as at 17th of Sept. Before the 16th of Sept, the total records of MAP Ready customers shared was 22, 245. The increase of 39,106 records shown was as a result of recent KYC process review. The current installation to meter payment run-rate is 62%.

Challenges

- Low level of meter stock: With the signing of the meter service agreement (MSA) in June 2019, MAPs have relied on existing meter stock as they currently experience a procurement lag of 3 months. To address this MAPs have been told to ramp up the number of available meters to cater for next three months demand.
- Manpower requirement: The lack of available skilled meter installers is another challenge being experienced. The demand for skilled installers is on the increase, with a need to retrain existing installers. To address this field officers are being recruited to meet demand by MAPs with a planned periodic retraining of identified field personnel.
- Project structure and management team. The need for an effective resource team is apparent with MAPs. Engagement with MAPs on restructuring is currently ongoing.
- An automated metering management system that allows for a controlled deployment and optimal metering experience. Most metering roll outs are done via a semi-automated system pending the deployment of an automated system.

6.5 Commercial operations investments

Linked to the following targets:

- Reduce ATC&C losses from the current level of 26% to 8.8%, which will allow our business to be sustainable;

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- Reduce the number of customer interruptions from the current level of 10,845 in 2019 to 3,554 by 2024, increasing reliability for our customers;
- Reduce the number of deaths and accidents in our service area to zero.

And to NERC's specific requirements for commercial systems.

6.5.1 Revenue protection plans

Links to the following

- Reduce ATC&C losses from the current level of 26.0% to 8.8%, which will allow our business to be sustainable

Table 20: Revenue Protection Investment Plan

Requirement	Units	Cost (Naira)	Capex (Naira Million) 2020
State-of-art software (Meter Data Management (MDM	1	20,000,000	20
Zera equipment	2	5,000,000	10
Clamp on ammeters (Fluke)	62	200,000	12
Total			**42**

6.5.2 Revenue Protection Project & Advanced Metering Infrastructure

In order to achieve our regulatory and business performance KPIs, IE strives to reduce losses through efficiency from our business process innovations. In line with this objective, Ikeja Electric operates a technology driven business model that guarantees efficient operations while reducing the dependence on human intervention.

In 2020, Ikeja Electric intends to deploy a state-of-the-art software enabled with a platform that would aggregate all current advanced metering infrastructure (AMI) - Table 20. This module is planned to be integrated with the ERP platform when deployed.

Our revenue protection plans also include the acquisition of meter testing equipment for the testing and monitoring of meters. The total required AMI related investment is N42 Million.

Table 21: Loss Reduction: strategies for manageable and difficult to manage areas

Task	Manageable	Non-Manageable
Regularization of consumers not registered as customers located in manageable areas.	Consumers in manageable areas visit our offices for KYC and the data feeds into our Billing database for proper regularization.	Energy Sales Representative (ESRs) takes the KYC forms to non-manageable areas and details are captured.
Assess consumption in areas with constraints limiting the utilities' field operations i.e. non-manageable areas.	Energy Consumed by DTs are either read remotely from the backend or physical visit by our Engineers to the DTs to capture energy consumed.	Engineers must visit DTs in non-manageable areas to capture energy consumed.
Regularization of service delivery (electricity supply and commercial operations) in non-manageable areas with high/medium commercial losses	Our Engineers carry out loss studies on feeders to determine commercial losses and take steps to reduce same. We also have a team that monitors and tracks customers who bypass their meters or connect illegally to our network.	

6.5.3 Regularisation of illegal customers

Commercial losses due to energy theft are one of the challenges Ikeja Electric intends to reduce over the next five years. Illegal energy activities result in increased cost for our customers due to the likelihood of regularised customers paying for stolen energy, which in turn is one of the factors responsible for lower customer satisfaction. With a 60% gap in customer meters, Ikeja Electric is faced with challenges of collecting revenues billed from regularised customers, with illegal activities further exacerbating our cashflow position.

Ikeja Electric will improve energy accountability through the following initiatives

- Metering of all trading points, from feeders all the way to the distribution transformers, to ensure proper energy accounting
- Procurement of distribution transformer meters to improve accuracy of Estimated Billing Methodology in billing unmetered customers.
- Continuous enumeration and mapping of customers and grid assets to ensure database accuracy.

- Increased vigilance and surveillance activities to guard against energy theft and identify free riders for possible energy recovery.
- Introduction of Meter Reading System in business units to enhance reliability of customer meter readings.
- Continuous installation and recertification of meters for non-maximum demand (NMD) and maximum demand (MD) customers.

6.5.4 Revenue protection for MDAs

Ikeja Electric plans to deploy 54 prepaid meters for MDA customers to improve billing and collection efficiency, at a cost of N85Million - Table 22. These meters include 21 for active and suspended accounts, 23 for dormant accounts and 10 replacements. NERC had issued a deadline for installation of MDA meters by August 19, 2019, however due to the challenges of the installation of the MDA prepaid meters, Ikeja Electric plans to complete installation by 2020.

Table 22: MDA Metering Investment Plan

					Capex (Naira Million)
Category	**Transformer Type**	**Meter Type**	**Unit**	**Cost (Naira)**	**2020**
Active and suspended MDA	500kVA	Prepaid Meter	5	7,000,000	35
Active and suspended MDA	less than 500kVA	Prepaid Meter	16	900,000	14
Dormant	less than 500kVA	Prepaid Meter	23	900,000	21
Replacement	500kVA	Prepaid Meter	1	7,000,000	7
Replacement	less than 500kVA	Prepaid Meter	9	900,000	8
Total			54		85

6.5.5 Management system plans

Status/Plan of various systems required by NERC:

- Commercial Management System (CMS): The CMS currently used by Ikeja Electric has the following modules, billing, service anomalies, billing adjustments, payments processing, service application, energy sales and assistance complaints. The meter management and meter information systems remain outstanding and will be procured as modules within the ERP system to be deployed by 2022.

- Enterprise Resource Planning System (ERP): Ikeja Electric intend to procure an ERP system from Oracle to be deployed by 2022. The ERP will be deployed with the following functionalities, financial, logistics, human resources and procurement. As shown in Table 23, the acquisition cost of the ERP is N4billion, with an annual maintenance cost of N400million.

- Geographic Information System (GIS): Ikeja Electric currently uses ArcGIS by Esri, with functionalities for customer and asset database, and the capability to link customer to network assets. Ikeja Electric plans to extend the functionality of its GIS with a network asset database and customer database and integrate with the ERP system. For the network database, plans to engage with Utility specialist in this subject matter. The road map and cost to develop this system will be in line with recommendations from the subject matter experts once this engagement is done. For the creation of the customer database, Ikeja Electric has the following plans

    - Ongoing customer enumeration exercise to close the gap between GIS and customer information system (CIS) database. The subsequent upload of customer information to CIS/CMS will be done after both databases are reconciled

    - GIS spatial analysis to improve customer and distribution transformer alignment. While this alignment in currently ongoing, finalisation of the GIS/CIS reconciliation will guarantee completion. Identified illegal customers will be escalated to the Business Units (BU) for regularization to reduce energy losses. The ERP to be purchased will also address this capability.

- Supervisory Control and Data Acquisition System: Ikeja Electric intends to deploy a SCADA system to be fully functional by 2024 - Table 24. The phased deployment plan consists of the following,

    - technical audit of system infrastructure

    - phased implementation of obsolete network assets to be SCADA compatible

    - phased installation of remote terminal units at injection substations,

    - Setting up of network operation centres at BUs with a master terminal unit, and a central control station at the headquarters.

The total implementation cost is N4.47billion.

- Works Management System (WMS): Ikeja Electric currently operates four isolated systems to achieve the works management system functionality. These are IE force, CRM, Mobi works. In a bid to achieve full integration of these systems, Ikeja Electric intends to procure WMS as a module within the ERP.

Table 23: ERP Investment Plan

(Naira Million)	2020	2021	2022	2023	2024
Acquisition		4,000			
Annual Maintenance			400	400	400

Table 24: SCADA Investment Plan

(Naira Million)	2020	2021	2022	2023	2024
Technical Audit of System Infrastructure	50				
Replacement of obsolete panels and switchgears to SCADA-compatible models		1,117	1,117	1,117	
Phased Installation of Remote Terminal Units (RTUs) at Injection Substations	670				
Set up a Network Operating Center with Master Terminal Units (MTU) and Human-Machine Interface (HMI)					400
Total	**720**	**1,117**	**1,117**	**1,117**	**400**

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6.5.6 Customer services

Links to the following targets:

- Improving Customer Resolution percentage from 85% to 95%;
- Achieving one quarterly CSR outreach over the next years;
- Reduce ATC&C losses from the current level of 26% to 8.8%, which will allow our business to be sustainable;

The major focus of the Customer Care Unit in Ikeja Electric is to provide exceptional service at every point of interaction. This is powered by the WOWe (Wow Experience) initiative, which is to ensure that all Customer Care Staff remember to exceed the customer’s expectation in service delivery. Our objectives are

- To improve customer satisfaction by achieving at least 90% Customer Complaint Resolution Index monthly in the short term, and 95% by 2024.

- To improve revenue growth generation by processing at least 100% of newly captured customers monthly and through on-site surveillance for energy theft and simulated collection activities.

- To build a strong and healthy customer database by capturing 100% customer information in Ikeja Electric's database

- To improve service delivery through uptime infrastructure delivery within franchise area

Our strategy to achieve these objectives include

- Developing new and improving existing Service Level Agreements (SLA) with all departments and units directly or indirectly involved in customer engagement and complaint resolutions

- Touch point (IE Connect and IE Serve) expansion in selected locations and ensure all customer care offices are revamped and well branded to reflect Ikeja Electric's mission.

As shown in Table 25, the total CAPEX and OPEX requirement over the next five years to achieve our objectives is N787million.

Table 25: New connections investment plans

			Naira Million		
	Quantity	Unit Price (Naira)	2020	2021	2022
IE Connect					
CAPEX					
Applications/Software	20	75,000	1.5	1.5	1.5
OPEX					
Furnishing & Retrofit -New Outlets	20	1,240,000	25	25	25
Commissions (Projected) -New Outlets	1	88,000,000	88	88	88
Commission DT Outsourcing-553	1	69,678,000	70	70	70
SMS System	1	3,250,000	3	3	3
IE Serve					
CAPEX					
Computer Hardware	2	2,500,000	5		
Applications/Software	2	1,000,000	2		
Queue Management System	15	5,000,000	75		

			Naira Million		
	Quantity	Unit Price (Naira)	2020	2021	2022
OPEX					
Avaya Call Center System Upgrade	1	2,500,000	2.5	3	3
Furnishing & Retrofit	2	2,000,000	4	4	4
Inverters	15	1,000,000	15	15	15
IE Serve	2	5,571,540	11	11	11
SMS System	1	15,000,000	15	15	15
Total CAPEX			84	2	2
Total OPEX			233	233	233
Total			**317**	**235**	**235**

6.6 Health and safety plans

IE’s plan over the next five years is to ensure the safety of life for both staff and the general public with a target of zero casualties and injuries recorded in our service area. This is line with the company’s mission and corporate safety vision, Harm to Zero (H20) geared towards the continue reduction of fatality to zero, thereby enhancing operational excellence and business performance in Ikeja Electric. Ikeja Electric has implemented the “Beyond Zero” programme which enhances occupational safety and health accountability at all levels. Ikeja Electric also uses a lesson learnt feedback mechanism “What Went Wrong” in updating business processes to guarantee safety. Ikeja Electric was in 2017, awarded the Corporate Pacesetter and Best Use of Social Media (organization) at the 2017 Nigeria Safety Award for Excellence and became the first company in the power sector to achieve the ISO 9001:2008 and OHSAS 18001:2007 international certifications by SGS. We have also established and inaugurated functional i-Empower (QHSE Academy) to help develop in-house safety leads (Safety Leadership Team) companywide.

The H20 target will be achieved with a combination of

- Targeted, regular and effective safety awareness trainings and campaigns within the community
- Regular staff engagements ad sensitization on safety.
- Procurement of safety equipment of our service personnel.
- Regular risk assessment for Ikeja Electric operations
- Regular facility and office inspections

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- Network monitoring for hazard identification using our Take Ownership programs and i-SAFE App, designed for easy and quick escalation of hazards.

The cost projections for IE's health and safety plan are presented in Table 26. The total CAPEX required over the next five years is N50Million, while the total OPEX required is N745Million. The cost summary comprises internal and customer facing safety requirements. For the internal costs, these include the procurement of adequate safety material and the installation safety equipment across IE substations and offices. Historical expense on internal safety requirements have seen a 60% reduction in employee casualties between 2015 and 2018, 350% increase in enforcement actions between 2015 and 2018, and a 60% reduction in major and minor injuries between 2015 and 2018.

The customer facing requirements include the cost of trainings and raising public awareness on the issues of safety. Our approach detailed in Annex E, include the annual safety (Table 45) and community engagement trainings (Table 46). Historical public awareness and safety campaigns including safety competence intervention programmes, technical safety leadership interactive forum, and technical safety discourse have seen a 63% reduction in third party casualties between 2015 and 2018. In 2019, a total of 2706 (16,737 training attendees since 2014) persons including staff have benefitted from our safety campaigns, while sensitization programmes have involved 83 communities. Proposed future trainings are captured in Table 27 and Table 28.

Table 26: HSE Investment Plan

Year	CAPEX (Naira Million)	OPEX (Naira Million)
2020	10	149
2021	10	149
2022	10	149
2023	10	149
2024	10	149
Total	**50**	**745**

Table 27: Planned annual safety trainings

Year	Name of Training	Details of each named Training
2019-2024	Technical Safety Discourse	Technical Safety Village Meeting with Technical staff and Leadership Team
	Internal QHSE Collaboration (Safety Competence Intervention Programmes)	Collaborate with Learning and Development Unit and other Departments to train employees
	Contractor Safety Engagements	Training of Contractors

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Table 28: Planned community engagements on safety

Year	Name of Training	Details of each named Training
2019-2024	Market Places and Public Safety Engagements	Market Places under the powerlines have been captured and plans to carry out radio shows are in order.

6.7 Resourcing plans

6.7.1 Human Resources plans

A Learning and Development needs analysis is done as part of the PIP to identify learning and development requirements for all staff through engagements with Heads of Departments and Unit. This exercise will drive the implementation of learning and development programmes through over the next five years; providing employees with new skills or upgrade on existing skills for improved performance in their core duties.

Adopting these techniques in identifying learning and development needs provides the Learning and Development team with insight as to the core challenges employees face on their jobs and skill gaps that cut across different job groups. This also informs the training cost of N2.1billion required over the next five years required to build and develop staff capacity in Ikeja Electric- see Table 29. These trainings include those for SCADA, NEPLAN, AutoCAD and the ERP system as described in Table 30.

Ikeja Electric's performance management system works towards the improvement of the overall organizational performance by managing the performances of teams and individuals for ensuring the achievement of the overall organizational ambitions and goals. The performance management system plays a very crucial role in managing performance in the organization.

We run a distinct performance management system. Our performance management cycle begins in January with employees agreeing with their Line Manager on their annual performance targets. Between June/July of the year, a mid-year performance review is done, while in December an annual performance review takes place.

Over the next five years, our network expansion and revenue protection plan will see the recruitment of more staff to effectively manage and monitor our operations. This will see result in a wage bill of N50billion over the period.

Table 29: Human Resource Investment Plan

	Naira Million				
HR Cost Projections	**2020**	**2021**	**2022**	**2023**	**2024**
Labor	9,053	9,505	9,981	10,480	11,004
Training	370	400	450	475	500
Total	**11,443**	**11,926**	**12,453**	**12,978**	**13,528**

Table 30: PIP Impact on HR Plans

Performance Improvement Plan Type	Details	Impact on unskilled staff	Impact on highly qualified staff
Network Expansion and Maintenance	SCADA	There is a need to acquire additional competencies for the remote monitoring of equipment	• Training on the use of the SCADA system for employees/ users • Improved operational efficiency • This also means all experienced users will need to continuously be trained due to changes and upgrade in technology and methodology of operation
	Additional feeder constructions and feeder maintenances.	Projected increase in the number of technicians required to manage the newly constructed feeders	Projected increase in the number of skilled and qualified employees (i.e. Engineers)
Metering through MAP rollout	Significantly higher metered customers in the network.	Likely decreased need for technicians who install meters internals as installation has been transferred to the MAP	Cross-functional training for field-based employees as potential changes of roles to include revenue protection and enforcement (RPE)
Improved management systems (Business Process Automation)	Purchase of ERP for companywide operations.	N/A	Cross-functional training on the new applications and processes.
	Deployment and use of software like AutoCAD and NEPLAN by	N/A	

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Performance Improvement Plan Type	Details	Impact on unskilled staff	Impact on highly qualified staff
	technical department.		

Impact of network expansion and maintenance, MAP, improved management systems on unskilled and highly qualified staff

6.7.2 Security

Since takeover Ikeja Electric has recorded significant milestones in the security of life and network assets. For our business to thrive, we believe the foundation of a strong security is a necessity, as such, we constantly assess business risks, develop adequate mitigants and adopt measures to contain or neutralise them. Our dynamic security environment, which requires regular updating of our security management approach to new challenges, is enabled through our Learning and Development programs for staff which is geared towards excellent service delivery.

Our outlook to conflict and security challenges is to deploy conflict resolution methods and involving constituted security agencies with law enforcement responsibilities in line with our corporate governance tenets on human rights. With our determination to promote sustainable development goal (SDG) 16, which seeks to promote peace, justice and strong institutions, we ensure that armed security personnel deployed on behalf IE by security agencies, the Nigerian Police Force (NPF) and Nigeria Security and Civil Defence Corp (NSCDC) comply with our internal policies which focus on protecting human rights.

Business security risks faced by Ikeja Electric include

- Violent attacks on employees on legitimate duty by delinquent customers
- Vandalism of critical assets
- Labour union activities
- Unwholesome activities of energy sales agents
- Energy theft

Historical security achievements and challenges are captured in Table 47. Significant achievements include partnerships with NPF on tackling security issues, deployment of electronic security systems in our BUs, community engagements for staff security, creation of the Ikeja Electric security command centre and the prosecution of criminals. Ikeja Electric continues to face security challenges notably from former NEPA staff, rogue security agency personnel, hostile communities and delinquent customers.

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The principles and values that underpin the implementation of our security strategic plan include

1) Maintain a collaborative culture for a safe and secure facility to work
2) Develop a comprehensive and collaborative approach to security that focus on people, property and processes.
3) Develop routine and emergency communication ability
4) Provide professional security training to security employees
5) Effective use of technology to create a safe and secure company.

To this end, Ikeja Electric intends to invest N240million over the next five years in our security - Table 31. This sum will be used to upgrade our command centre, procure additional vehicles for patrol, upgrade and install security systems, install alarms and electronic surveillance equipment.

Our outlook over the next five years is to save lives, protect the environment, prevent energy and commercial losses and the damage to network assets, preserve Ikeja Electric's reputation and ensure the confidence of employees and stakeholders.

Table 31: Security Investment Plan

		Naira (Million)				
CAPEX	**Units**	**2020**	**2021**	**2022**	**2023**	**2024**
Upgrade of Command Centre		15	-	-	-	-
Procurement of patrol vans	8	30	-	20	-	35
Upgrade of electronic systems in 3 locations	3	10	-	-	-	-
Installation of electronic systems in BU	31	-	30	-	25	-
Installation of alarms in BU & UT		-	10	-	-	-
Installation of electronic surveillance and access control systems		-	-	50	-	15
Total		**55**	**40**	**70**	**25**	**50**

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6.8 Achieving Cost Efficiency

For us, effective supply chain management ensures service delivery, avoids revenue loss due to operational downtime and ensures that the organisation receives value for money spent. For our customers, our procurement practices are important as delay in provision of necessary materials can lead to downtime in fault clearing, which in turn disrupts the lives and businesses of our customers. Our ability to secure high quality materials and equipment has an impact on customer safety and the stability of electricity supply.

Also, our procurement practices have a significant impact on our employees, as poor sourcing practices could lead to an increase in their workload and could also expose them to safety hazards. To achieve this, our vendors are evaluated for most of the categories; with competitive quotes were received for every request sent by the user department. Supply Chain policy aims at promoting fiscal discipline by entrenching planned procurement processes and cycles. It also encourages competition and reduces the reliance on single source suppliers. Thus far, the policy has helped promote fairness and transparency in dealing with third parties.

6.8.1 IE Procurement Process

Upon receipt of a request by Procurement unit, the following processes are observed from selection of vendor to award of contract:

1) Head SCM gets the approved request and assigns it to a procurement personnel.
2) The personnel sends out request for quote, thereafter carries out comparative analysis of quote to determine the most competitive quotes (i.e. in terms of quality, delivery period, price etc.). The most competitive vendor's quote is recommended and ratified.
3) The Authority to Procure (ATP) for the selected vendor is prepared for approval by the procurement personnel.
4) The ATP is endorsed by the Head, SCM and approved by the Chief Financial Officer (CFO)
5) The approved ATP is forwarded to Treasury unit for input of payment window/period for the transaction
6) The ATP is returned to procurement and works order is prepared
7) The works order is approved by CEO and Head of the requesting department.
8) The vendor signs and stamps the work order and returns the company's copy.
9) The job is carried out as contained in the contract document

In Annex F. 1, the procurement details of the Mangoro ISS project in Section 5.4 is presented. The most competitive quote of N25.9million was selected out of 7 vendor submissions (highest quote – N42.3million), evidencing cost efficiency. In Annex F. 2, the procurement details for the Adiyan 11kV feeder extension is also presented; the quote with the shortest delivery period of two weeks and lowest cost (N11.7million) was selected out of 12 vendor submissions (highest quote – N26.8million).

This approach to cost efficiency has guided the investment costs considered for our performance plan.

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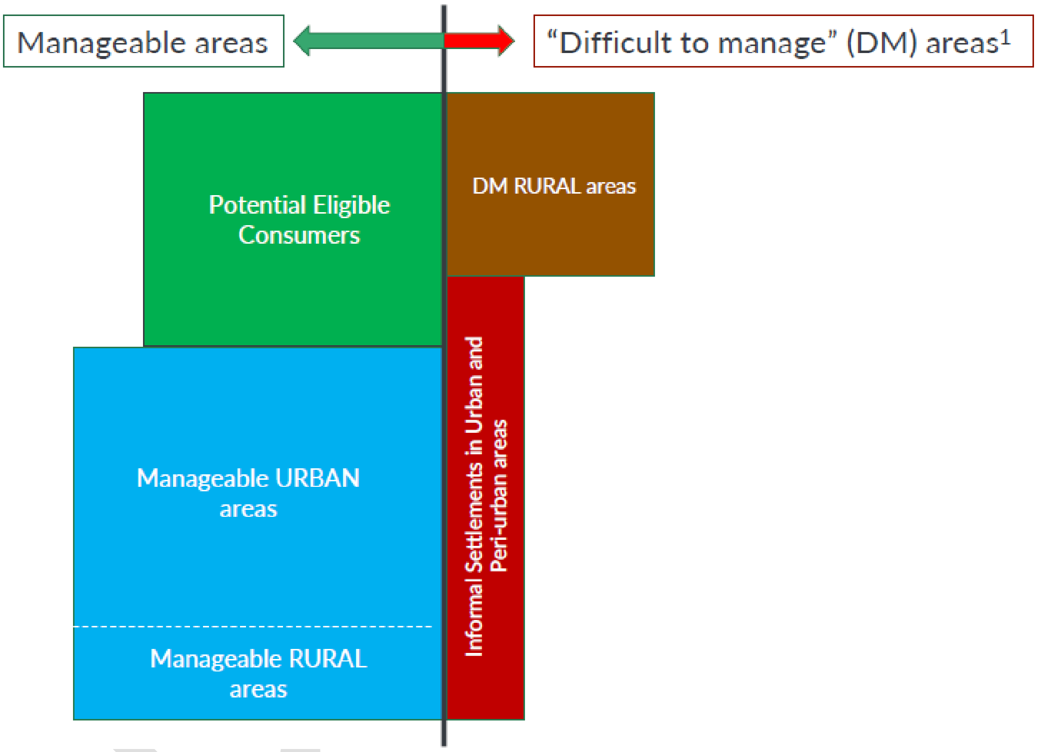
6.9 Innovative Approaches

Our plan is to segment our customers and the network assets through which they are supplied into different market segments (manageable and difficult-to-manage) as shown in Figure 12 to address the challenges of the different customer market segments shown in with different strategies.

Using our Optimisation Model for Network Investments (OMNI) model, Ikeja Electric can rank and classify our feeders into different market segments.

Figure 12: Four market segments defined by CaBTAP[2]



6.9.1 Manageable Areas

The Premium Power Initiative is an enhanced level of power supply and associated services to customers in the following communities / estates in Lagos, Magodo GRA and Ikeja GRA, and other locations under our network coverage that may indicate their interest in a willing buyer – willing seller alternative power supply arrangement – See section 6.9.3. Under this initiative, the provision of electricity supply goes beyond existing standards with guaranteed

[2] Capacity Building and Technical Assistance Programme (CaBTAP) presentation 18-19 June 2019. NERC has divided the market into manageable and unmanageable areas.

performance levels, bearing in mind that the status quo of power availability is between 6 to 15 hours per day.

Our plan is that the Premium Power Initiative will entail the provision of dedicated technical and commercial services to identified customers who are desirous of paying above the current retail tariff. Consequently, customers in certain residential estates and industrial customers are indicating willingness to pay higher tariffs for improved and reliable power supply under the PP Initiative, which is relatively cheaper than the traditional alternative electricity supply arrangements currently in existence.

It is our plan that the Premium Power Initiative will not only enable us to retain our market share under our franchise area but create an enabling environment to effectively provide enhanced services to willing buyers.

The value proposition under the Premium Power Initiative is stated below;

Technical

- Supply of power at an average of 22 hours per day which translates to a minimum of 660 hours in a 720-hour month. 22 hours instead of 24 hours is to cater for instances of planned maintenance and grid collapses;
- Supply of quality power at the required voltage levels;
- Routine preventive maintenance of power assets (transformers, feeders etc.) will be carried out to prevent fault occurrences and ensure that the agreed availability is achieved; and
- Provision of dedicated fault clearing crew to ensure that technical faults are cleared within the stipulated time contained in the Service Level Agreement (SLA).

Customer Service

- Provision of accessible 24/7 payment channels for ease of vending;
- Provision of dedicated contact numbers and email address to cater for complaints from PP customers;
- Outage Notification - Notification of power interruption will be served via email/SMS 24 hours before each planned maintenance;
- Provision of dedicated Key Accounts Management team to resolve all issues within stipulated timelines per the SLAs; and.
- Provision of a premium Contact Centre lounge to serve premium customers.

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Metering

- Provision of AMI meters to all customers;
- Provision of meter maintenance services and immediate meter replacement for faulty meters; and
- Provision of data to assist residents manage their energy consumption.

6.9.2 Difficult to Manage (DM) Areas

Difficult to manage rural areas

The difficult-to-manage rural areas will be our priority for franchising. We are willing to work with distribution sub-franchisees that can provide services in the following areas:

- Metering, Billing, and Collection
- Total management of part of our distribution network
- Supply power and manage part of our distribution network

Informal Settlements in Urban and Peri-urban areas

Identified community settlements in urban and peri-urban areas will be engaged to determine affordable tariffs and energy requirements. Based on agreed commercial commitments from the settlements, proposed strategies include

- Bulk metering for the community
- Distribution of bulk bills for the community
- Supply based on payment performance from the community
- Engagements with the state and local governments to determine energy subsidies and network investment support for poorer settlements.

6.9.3 Premium Power Supply Projects

Premium Power will be delivered through the existing 100MW bilateral power arrangement with Egbin Power Plc.

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We note that one of Egbin Power Plc's 220 MW power plants (Unit 6) is isolated, which provides Ikeja Electric the advantage of procuring Egbin's excess power for the purposes of supplying premium power customers uninterrupted supply through the transmission network (under the extant transmission use of service agreement- TUOS) and Ikeja Electric investing in upgraded lines to deliver the power.

Pursuant to Ikeja Electric's TUOS with TCN, it guarantees that the earmarked feeders for Premium Power will be given priority by TCN, therefore securing the availability obligated to the Premium Power customers. Our obligations also include a liquidated damages provision to cater for non-performance by TCN as contained in the power procurement agreement (PPA) between Ikeja Electric and the Premium Power customer.

The PPA with the customers also include SLAs on availability, maintenance, turnaround time on fault clearing and prescribe penalties in the event of default by Ikeja Electric and stipulates the responsibility of Ikeja Electric to undertake infrastructural upgrade of the power facilities in order to deliver the availability committed to in the PPA.

Premium Power Marketing and Implementation Strategy

The bedrock of our marketing plan is to provide a service that can be delivered completely independent of the National Grid's limitations. Hence, our medium to long-term Premium Power delivery strategy - Table 33, will require IE to construct dedicated feeders and substations (where not available) along the routes identified for Premium Power sale.

This will be implemented with the following steps;

Customer(s) formally request or IE Identifies a location with a cluster of potential Premium Power targeted customers;

- Estimate the load requirement of these customers and the maximum population required;
- Conduct feasibility and viability of providing Premium Power;
- Construct dedicated feeders and Distribution Transformers that will deliver supply to these customers;

- Ensure these dedicated supply lines have the potential to deliver 24/7 power supply;
- Ensure there are visible dedicated maintenance teams patrolling the feeders regularly; and
- Connect these customers to supply once a power purchase agreement is executed at the agreed tariff agreed by the parties.

Table 32: Premium Power Implementation Approach

Phase	Implementation
Pre-Feasibility Study.	An insightful analysis of the proposed location(s) (estates or industrial/commercial clusters) will be conducted to provide a high-level business justification towards a sustainable revenue growth by the marketing team. The Technical team will also conduct a high-level appraisal of the prospect and provide recommendations. Concurrently, an assessment is conducted out to establish the level of the technical upgrade and metering required.
Obtain internal approval	The Commercial team obtains required approvals based on commercial and technical recommendations.
Engagement of prospective customer	The Commercial team commences discussions with prospective customers, which culminates in the execution of a Memorandum of Understanding (MOU) and subsequently PPA.
Execution	• Upgrade of the technical infrastructure and metering commences. • Customer starts enjoying Premium Power services.

Table 33: Premium Power Implementation Strategy

Negotiation	Description	Short Term (0-6months)	Mid Term (7-24 months)	Long Term (>24 months)
Customer agreements	SLA	SLA based on 18-22hours/day	N/A	SLA based on 24hr availability

Negotiation	Description	Short Term (0-6months)	Mid Term (7-24 months)	Long Term (>24 months)
		SLAs on fault clearing, complaint resolution and meter related issues		
Technical	Technical Survey	Technical survey to determine technical improvements based on existing infrastructure	Technical survey based on improving and upgrading infrastructure	Survey aimed at creating redundancy
	Injection Substations (ISS)	Replacement of bad/faulty/obsolete switch gears, filtration of power transformers, maintenance of protection systems, etc.	Incorporate spares for ISS equipment; and facility upgrade of the ISS	Building redundancy for power transformers; incorporate SCADA
	Feeder (11kV & 33kV)	Replace every defective line accessory, and vegetation management	Reconductor all lines to ensure they are up to regulatory standards	Build redundancy for lines, and incorporate intelligent devices for network monitoring
	Distribution transformers (DT)	Replace all defective DT accessories (line tap, DT-Fuse), and relief of overloaded DTs	Fencing of transformers; acquire spare DTs for redundancy	Incorporate intelligent devices for DT monitoring; and build redundancy at DT level (50% max loading)
	Low Tension (LT)	Replace all defective LT accessories (line tap, insulators, poles)	Reconductoring all lines to meet regulatory standards	

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Negotiation	Description	Short Term (0-6months)	Mid Term (7-24 months)	Long Term (>24 months)
Metering	Metering Survey	Metering survey aimed at achieving 100% pre-paid metering	Metering survey to identify faulty and obsolete PPMs	100% fully functional pre-paid meters

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7 Financial plan

7.1 Overview

This section covers:

- Zero CAPEX Outcome;
- MYTO CAPEX Outcome;
- Full CAPEX Outcome; and
- Funding Plan.

In each scenario, it is assumed that the CAPEX amount stated is the CAPEX amount that will be funded, ceteris paribus.

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7.2 Zero CAPEX Outcome

7.2.1 Inputs

This is a scenario that assumes that Ikeja Electric will not be able to raise any funds needed for CAPEX investments.

The tariffs used at MYTO Minor Review tariffs for 2020 to 2024. The energy received from 2020 till 2024 is assumed to be the same with 2019 projected levels till year end. The 2019 ATC&C loss levels remain till 2024, although without any Capex investment, losses will likely increase.

Table 34: Zero CAPEX Inputs

Assumptions	2020	2021	2022	2023	2024
Capex (billion N)	15,157	15,157	18,947	18,947	18,947
ATC&C Actual	10.8%	8.8%	8.8%	8.8%	8.8%
ATC&C NERC tariff	10.8%	8.8%	8.8%	8.8%	8.8%

7.2.2 Outputs

Without any CAPEX investments, Ikeja Electric will not be able to fully remit to the market as expected by NERC, with NBET bills remittance incomplete as shown in Table 35 below. In this outcome, there is nothing available for operating expenditure which will mean the business cannot operate.

Table 35: Zero CAPEX Outputs

	Unit	2020	2021	2022	2023	2024
Cost-reflective tariff	N/kWh	46.62	46.29	46.16	46.49	46.62
Allowed tariff	N/kWh	37.92	37.06	36.72	36.91	37.35
Opening cash flow	₦m	1,939	-	-	-	-
Receipts						
Cash Collection from Credit customers	₦m	208,750	213,255	235,301	255,188	273,002
Equity Injection	₦m	-	-	-	-	-
Bank loan drawdown	₦m	-	-	-	-	-
Shareholder Loan	₦m	-	-	-	-	-
Payments						
Payment to NBET	₦m	162,274	170,291	189,382	206,478	223,292
Payment to MO	₦m	38,383	40,987	43,942	46,837	49,710
% of NBET Bill Paid	*%*	100%	95%	94%	94%	95%
% of MO Bill Paid	*%*	100%	100%	100%	100%	100%
Loan Payment	₦m	1,979	1,977	1,977	1,873	-
Loan Default	₦m	-	-	-	-	-
Staff Cost	₦m	1,785	-	-	-	-
% of staff cost paid	*%*	15%	0%	0%	0%	0%
Accounts Payable	₦m	3,042	-	-	-	-
Taxation and VAT	₦m	3,226	-	-	-	-
Capex	₦m	-	-	-	-	-
Cash available for distribution	₦m	-	-	-	-	-
Dividends	₦m	-	-	-	-	-
Cash available after dividends	₦m	-	-	-	-	-
Closing cash flow	₦m	-	-	-	-	-

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7.3 MYTO CAPEX Outcome

7.3.1 Inputs

This is a scenario that assumes that Ikeja Electric will be able to raise the Regulatory Allowed CAPEX needed for CAPEX investments.

The tariffs used at MYTO Minor Review tariffs for 2020 to 2024. The energy received from 2020 till 2024 is same as assumed in the MYTO Minor Review model. The ATC&C loss reduction projection is a trajectory that Ikeja Electric can achieve given the limited Regulatory Allowed Capex for 2020 to 2024.

Table 36: MYTO CAPEX Inputs

Assumptions	2020	2021	2022	2023	2024
Capex (billion N)	15,157	15,157	18,947	18,947	18,947
ATC&C Actual	15.2%	10.8%	8.8%	8.8%	8.8%
ATC&C NERC tariff	10.8%	8.8%	8.8%	8.8%	8.8%
% of CAPEX from IGR	30%	30%	30%	30%	30%
% from Debt	70%	70%	70%	70%	70%
Debt Rate	9%	9%	9%	9%	9%
Tenor – Debt (years)	17	17	17	17	17

7.3.2 Outputs

In this outcome, CAPEX funding is raised but due to the tariffs not being cost-reflective, funds generated from the operations are insufficient to cover market bills. there is nothing available for operating expenditure which will mean the business cannot operate and a default on the loan repayment will occur.

Table 37: MYTO CAPEX Outputs

	Unit	2020	2021	2022	2023	2024
Cost-reflective tariff	N/kWh	46.62	46.36	46.29	46.68	47.35
Allowed tariff	N/kWh	37.92	37.06	36.72	36.91	37.35
Opening cash flow	₦m	1,939	-	-	-	-
Receipts						
Cash Collection from Credit customers	₦m	208,750	215,470	237,745	257,838	275,837

	Unit	2020	2021	2022	2023	2024
Equity Injection	₦m	-	-	-	-	-
Bank loan drawdown	₦m	-	-	-	-	-
Loan	₦m	11,130	11,340	15,358	17,718	17,718
Payments						
Payment to NBET	₦m	162,274	172,506	191,825	209,128	226,127
Payment to MO	₦m	38,383	40,987	43,942	46,837	49,710
% of NBET Bill Paid	%	100%	97%	96%	96%	97%
% of MO Bill Paid	%	100%	100%	100%	100%	100%
Loan Payment	₦m	1,979	1,977	1,977	1,873	-
Loan Default	₦m	0	2,630	4,428	6,501	8,575
Staff Cost	₦m	1,785	-	-	-	-
% of staff cost paid	%	15%	0%	0%	0%	0%
Accounts Payable	₦m	3,042	-	-	-	-
Taxation and VAT	₦m	3,226	-	-	-	-
Capex	₦m	11,130	11,340	15,358	17,718	17,718
Capex used (%)	%	70%	70%	70%	70%	70%
Cash available for distribution	₦m	-	-	-	-	-
Dividends	₦m	-	-	-	-	-
Cash available after dividends	₦m	-	-	-	-	-
Closing cash flow	₦m	-	-	-	-	-

7.4 Full CAPEX Outcome

In the Full CAPEX outcome, it is assumed that Ikeja Electric will be allowed to invest a higher CAPEX than the Regulatory Allowed CAPEX. It is also assumed that Ikeja Electric can charge a truly cost-reflective tariff which will cover the investment requirement and will put us in a better financial position to raise funds. In this scenario, Ikeja Electric will achieve an ATC&C level of 10% by 2024.

7.4.1 Inputs

Table 38: Full CAPEX Inputs

Assumptions	**2020**	**2021**	**2022**	**2023**	**2024**
Capex	15,900	16,200	21,940	25,312	25,312
ATC&C Actual	17.5%	14.1%	11.6%	9.9%	8.8%
ATC&C NERC tariff	17.5%	14.1%	11.6%	9.9%	8.8%
% of CAPEX from IGR	30%	30%	30%	30%	30%
% from Debt	70%	70%	70%	70%	70%
Debt Rate	9%	9%	9%	9%	9%
Tenor – Debt (years)	17	17	17	17	17

7.4.2 Outputs

In 2020, the average tariff increases to 50.52 N/kWh as against the 37.92 N/kWh in MYTO 2019, which will allow Ikeja Electric settle market bills, fund both CAPEX and OPEX, and settle our debt obligations. This trend will then be expected to continue over the next years.

Table 39: Full CAPEX Outputs

	Unit	2020	2021	2022	2023	2024
Cost-reflective tariff	N/kWh	50.25	49.17	47.75	47.32	47.55
Opening cash flow	₦m	1,939	-	-	-	-
Receipts						
Cash Collection from Credit customers	₦m	254,053	269,802	300,242	327,182	351,716
Equity Injection	₦m	-	-	-	-	-
Bank loan	₦m	-	-	-	-	-
Loan	₦m	11,130	11,340	15,358	17,718	17,718
Payments						
Payment to NBET	₦m	160,754	175,869	197,075	214,006	227,703
Payment to MO	₦m	38,383	40,987	43,942	46,837	49,710
% of NBET Bill Paid	%	100%	100%	100%	100%	100%
% of MO Bill Paid	%	100%	100%	100%	100%	100%
Loan Payment	₦m	1,979	4,607	6,405	8,374	8,575
Loan Default	₦m	-	-	-	-	-
Staff Cost	₦m	11,189	12,547	14,069	15,776	17,691
% of staff cost paid	%	100%	100%	100%	100%	100%
Accounts Payable	₦m	19,071	14,099	15,769	17,640	19,737
Taxation and VAT	₦m	20,222	12,364	6,711	7,217	7,708

	Unit	2020	2021	2022	2023	2024
Capex	₦m	15,524	16,200	21,940	25,312	25,312
Capex (%)	%	98%	100%	100%	100%	100%
Cash available for distribution	₦m	-	4,469	9,689	9,737	12,998
Dividends	₦m	-	4,469	9,689	9,737	12,998
Cash available after dividends	₦m	-	-	-	-	-
Closing cash flow	₦m	-	-	-	-	-

7.5 Funding Plan

Ikeja Electric plans to fund 30% of its CAPEX requirement through funds generated from the business as return on capital investments component of our allowed costs. We also intend to fund 70% through a commercial loan from the Bank of Industry, at an interest rate of 9%- and 17-year tenure. This is currently the cheapest source of funds available to Ikeja Electric.

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8 Risk assessment and management

8.1 Overview

This section covers:

- Approach to managing risk; and
- Risk analysis.

8.2 Approach to managing risk

Ikeja Electric has carried out a risk analysis of the business environment in the coming years. The following four step approach to risk management was followed:

- A series of risk identification sessions were held in which the major technical and commercial risks to the Performance Improvement Plan were identified and listed;
- A subjectively assessed risk likelihood was assigned to each identified risk according to the following ranges:
  - High: 67% - 100% probability of occurring
  - Medium: 34% - 66% probability of occurring
  - Low: 0% - 33% probability of occurring
- Similar subjectively assessed impacts (high, medium, low) were attached to each identified risk.
- For risks assessed as being high/medium or above the following risk management strategies were formulated:
  - Avoidance (eliminate, withdraw)
  - Reduction (optimize – mitigate)
  - Sharing (e.g. insure, transfer)
  - Retention (accept and budget)

The risk analysis is summarised in the next section.

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8.3 Risk analysis

Table 40 provides a risk assessment for this performance improvement plan.

Table 40 – Risk assessment and management

Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
Brief title	*Description*	*e.g. High, medium, low*	*e.g. High, medium, low*	*Avoidance (eliminate, withdraw)* *Reduction (optimize – mitigate)* *Sharing (e.g. insure, transfer)* *Retention (accept and budget)*
Loss reduction pathway in tariffs.	Discos have argued that NERC should recognize the actual loss position of the Discos. Discos have been unable to reduce losses due to non-cost reflective tariffs, low CAPEX allowance in the MYTO which doesn't reflect reality, high energy charges from NBET, and MDA collection loss is yet to be addressed. The timeline of non-cost reflective tariffs is provided in Section 4.2.4.1 in Table 3.	High	High	**Retention** *(accept and budget).* The decision on tariffs is outside the direct control of the Discos. Within the different scenarios modelled in section 7, we have considered different possible scenarios for allowed ATC&C losses. We have considered the impact this will have on Disco performance during the tariff period. It will be important to **negotiate with NERC** to avoid the worst tariff scenarios.
MDA payment.	MDA debts are not paid to date, current deliberations between the Discos and FGN only focuses on federal MDAs and not state. Discos need to engage with state MDAs to address the debt currently being accrued at the state level.	High	High	**Retention** *(accept and budget).* The decision on tariffs and the solution to MDA debt payment is outside the direct control of the Discos. Within the different scenarios modelled in section 7, we have considered different possible scenarios for MDA payment.

Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
				It will be important to **negotiate with FGN** to avoid the worst MDA scenarios.
Performance agreement timescales.	The performance agreements end date was originally December 2019. BPE has indicated that 2017 and 2018 will be treated as non-performance years.[3] However, they are treating 2015, 2016 and 2019 as loss reduction years. None of the Discos have achieved the first three years of loss reduction, and even with cost reflective tariffs, it is unlikely they will achieve their full loss reduction commitment by the end of 2021. Based on the current performance of the Discos, the call option to buy back the Discos at $1 if they fail to meet their commitments.	High	High	**Avoidance** *(eliminate, withdraw).* Under the current treatment of the loss reduction targets, Discos can use their businesses without compensation. This makes it very challenging to finance improvements unless the targets are made more achievable. This risk is not possible to manage, unless BPE amend the performance agreement targets to reflect an achievable trajectory. **Negotiating with BPE is essential.** If this is not resolved, the business may not be viable.
Minor review.	No minor review has been implemented in tariffs since 2015 to date leaving the Discos operating under impossible economic conditions, and unable to meet their obligations.	High	High	**Avoidance** *(eliminate, withdraw).* Failure to implement a minor review could qualify as a "change of law" force majeure event under the performance agreement, since the regulation is not being enforced. By declaring force majeure within the timescales, Discos would protect themselves from the performance targets and make themselves eligible to receive full compensation if the situation is not rectified in performance agreement timescales. To date, Discos have been reluctant to declare force

[3] BPE - Presentation on the Review of Performance Target Dates of the DISCOS (21st February 2019)

Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
				majeure because of political implications. Once new performance agreements and tariffs have been implemented, Discos should enforce their entitlement to a cost-reflective tariff.
NBET charges for generation inconsistent with Disco tariffs.	The NBET invoices issued to the Discos have remained significantly higher than MYTO projections, largely because NBET has been charging the Discos using the actual economic indices i.e. forex etc. However, the tariffs used by NBET remain higher than the generation tariff in the June 2019 MYTO minor review model. Once PPAs are activated, generation costs will deviate further from MYTO assumptions as capacity factors will be considerably higher once successor and NIPP generators can charge for available capacity.	High	Low (providing minor reviews implemented)	**Retention** *(accept and budget).* The scenarios in this report assume that generation tariffs are consistent with NBET current tariffs in real 2019 terms. This is addressed retrospectively when NERC use actual NBET invoices in minor reviews but will have an impact in short term cashflow and ability to meet market remittances. **Regulatory need.** NERC are requested to ensure their generation tariff formulae are consistent with those being applied by NBET, and that the capacity factor assumptions are consistent with SO declarations for all generation, so that the MYTO model provides a realistic tariff base.
Generation levels.	In past MYTO models, forecast generation levels have been significantly in excess of reality. Actual generation levels have changed very little since 2013. When there are generation shocks (such as in 2016), there is a disproportionate impact on payment, due to customer dissatisfaction and the fact that fixed costs are spread over fewer kWhs.	High	High	**Retention** *(accept and budget).* The scenarios in this report assume that generation levels remain at 2019 levels, with no increase. **Regulatory need.** MYTO minor reviews will be essential for tariffs to keep pace with generation levels.

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Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
Eligible Customers.	Some transmission connected customers of the Discos have self-declared themselves eligible customers and are currently receiving power illegally through TCN. 37 customers at risk with a monthly impact of N1.07billion. Customers who self-declare themselves without due process create a risk to Disco revenue, financial performance, energy received and customer numbers. At present, TCN is refusing to Disconnect illegally defaulting customers as required under the Supplementary Order on the Commencement of TEM.	High	High	**Avoidance** *(eliminate, withdraw).* If the market issue is not resolved, and tariff levels are not adjusted to compensate, the only option for some Discos may be withdrawal via force majeure. **Regulatory need.** It is important that any Eligible Customers pay the Competition Transition Charge (CTC) and that their status is legal.
Meter Assets Providers (MAP).	The MAP regulation has been in effect for over a year now, however there has been limited progress by the MAP's in commencing metering. Recent reports indicate that several MAP's currently do not have the necessary finance to commence metering within the set timelines. Metering is likely to be based only on those customers who can afford to pay. Discos are not permitted to use regulated CAPEX for metering.	High	High	**Reduction** *(optimize – mitigate)* Ikeja Electric has managed their MAP contracts to ensure best possible service. SLAs and KPIs are have been included in the MAP contracts to measure performance and enforce agreements. However, a residual risk remains because the metering allowance by NERC is not adequate to allow financing of metering, therefore all meters will initially be financing by the customers themselves. Many of our customers may not be able to finance the CAPEX, particularly the R2 customers. **Regulatory need.** It is important that NERC reviews the metering CAPEX allowance to enable third party

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Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
				financing of meters and to ensure that metering can reach all our customers.
Allowed CAPEX in MYTO model.	If allowed CAPEX is not consistent with assumptions, it will restrict the ability of Ikeja Electric to make the required investment and may prevent the planned Outputs being achieved.	High	Medium	**Retention** *(accept and budget)* We have prepared this PIP for a range of allowed CAPEX scenarios, and the projected outputs will differ depending on the allowed CAPEX.
Limited or no access to finance.	The regulatory uncertainty, non-cost reflective tariffs since privatisation in 2013, and the fact that most Discos are effectively insolvent mean that commercial lenders are unwilling to lend to Discos. Investors have not received dividends.	High	Medium	**Retention** *(accept and budget)* In our financial planning, we have considered known sources of finance. We have considered cases where investment is financed out of free cashflow rather than commercial lending We have also anticipated obtaining funds from the Bank of Industry's Power and Aviation Fund. We also intend to utilise the Nigeria Electrification Roadmap infrastructure funding facility of the FGN and the German government.
Acknowledged tariff shortfall covers liability.	NERC anticipated that liability to MO and NBET will be reduced by the tariff shortfall. However, NERC's calculation of the tariff shortfall differs from Ikeja Electric's, as discussed in section **Error! Reference source not found.**.	High	Medium	**Retention** *(accept and budget)* We have considered a range of tariff scenarios based on a range of acknowledged tariff shortfall scenarios, and the projected outputs will differ depending on NERC's acknowledged tariff shortfall.
Project delivery timescales.	We have planned this PIP based on expected delivery timescales. However, there is a risk that external contractors may not deliver the work to time.	Medium	Medium	One of our vendor selection criteria is project delivery time which allows us to identify vendors with the fastest turnaround times, and we have SLAs in our agreements that guide delivery.

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Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
Insurgency activities damage Ikeja Electric assets (or other extreme events beyond Ikeja Electric's control e.g. extreme weather).	In recent years, insurgency and civil unrest has caused damage to electricity infrastructure in Nigeria. There is a risk of recurrence. Other extreme events could include (for example) extreme weather or seismic events.	Medium	High	**Sharing** *(e.g. insure, transfer)* It is possible that specific investment to address short-term insurgency activities could be allowed for in tariffs as additional CAPEX, and outputs and/or allowed CAPEX could be reviewed in an extraordinary tariff review following these or similar extreme events. **Avoidance** *(eliminate, withdraw).* The Performance Agreement allows for withdrawal in the case of severe or prolonged insurgency and other specific force majeure events.

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Annexes

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Annex A Results of stakeholder consultation

A. 1 Stakeholder Engagement in Akowonjo BU

Background information: To create awareness on the MAP process for the PIP, share lessons/feedback and address customers' concerns

Undertakings: 11
Venue: Grand Ovation Event Centre Mosholashi Bus stop, Gowon
Date: 23rd August 2019
Time: 10:50am – 12.40pm

Attendance

Customers = 198
Traditional Rulers = 7
CDCs = 9
CDAs = 97
Licensed Electrical Contractors of Nigeria
Federal Competition & Consumers Protection Council
MAP Registration Vendors = 2
IE Reps (CHQ, & BU teams) = 28
Brand Ambassadors = 8
Conlog = 15

Issues Raised

- Request for free meters
- Tenor of debt repayment and its effect on survey for metering
- Process of updating personal details
- Length of debt resolution process
- Landlords vs tenants: Who should pay for the meter?
- Request for registration centres in communities
- Customers who made payment pre-privatisation but are yet to be metered
- Refund to customers on cost of meters
- Pre-privatisation debts
- Account separation
- Payment in instalments for meter
- Request to end load shedding & relief for overloaded DTs
- Channel for complaints on new meters
- Request to route MAP registration through CDAs
- What happens to customers with analogue meters?
- Metering of multi-tenanted apartments
- Metering on streets with bad poles
- Why is BVN requested for registration?
- What to do if customer is not satisfied by the debt resolution verdict?

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- Accumulated debt due to duplicated billing
- Extension of debt repayment to 60 months
- Agbado/Oke-Odo LCDA request for mass adjustment beyond debt-resolution team
- Registration for those without email addresses
- Immediate availability of meters
- Request for 24-hour services by technicians on installation hitches
- 1 + 1 policy
- Uncredited payments

Observations

- The event was rated as the best so far by the CHQ team in terms of venue, ambience, logistics, attendance, audience engagement and response. Although the event was planned in just three days.
- 21 customers were registered on site.
- The presentations by IE and Conlog were spot on. The lessons learnt (from the pilot) shared with the attendees will help the process from registration to metering become easier.
- Also, the attendees were shown the meter samples and what the installers/commissioners looked like, so they know what to expect
- To curb errors in documentation/payment, Conlog would be issuing letters and tellers to each surveyed customer
- Learning points.
- Need to give ample time for planning and longer notice to the community leaders.
- Way Forward.
- Customers who have been surveyed in the last one week are to be metered by Conlog immediately.
- The biggest information from the engagement was to copy the ARN correctly.

A. 2 Stakeholder Engagement in Shomolu BU

Background information: Customer Engagement was organized to sensitize customer on how to get metered through MAP. Invites were sent to stakeholders under the Shomolu network. Other invitees are customers, CDA representatives and the media. Both IE and Mojec representatives took turns to speak to the audience on how to the process of getting metered.

Venue: Quad T, 171 Oworonshoki Expressway Gbagada Gowon
Date: 8th August 2019
Time: 10:50am – 12.40pm

	Name	Position held
1	Customers	489

	Name	Position held
2	Mr. Odunsi Adeboye	CDC Chairman
3	Mr. Stephen Folami	Kosofe LGA
4	Otunba Odutola	Shomolu LGA
5	Mr. Afolabi	Alapere Agboyi Ketu
6	Mr. Adesoji Adewole	Kujore South Ojota
7	Hon. Mrs. Kuponiyi	Bariga Vice Chairman & 700 others (Press men, Mojec staff, partner banks& representative)

IE executives

	Name	Ikeja Electric Representative
1.	Engr. Olanrewaju Yusuf	BM
2.	Mrs. Folake Soetan	COO
3.	Felix Ofulue	Head Corporate Comms
4.	Mr. Ayeni Olusola	External Comms Lead
5.	Halima Shuaibu	External Comms
6.	Ijeoma Ezeolisah	External Comms
7.	Fadeke Omo-Omorodion	External Comms
8.	Staff from all the UTs in Shomolu, HQ, MAP Ambassadors	

Issues Discussed

- Keynote Address by COO Folake Soetan (Journey so far, Efforts by management, and management's commitment to metering all customers)
- Speeches from the MD, Mojec Ms. Chantelle Abdul and the Chairman Mojec, Mrs. Mojisola Abdul
- Verbal and Video presentation led by Metering Project supervisor Adeniyi Odutayo
- An Overview of MAP by BM, Shomolu
- Partner Banks presentation on how to access loan to purchase meter

Q&A from Customers

- Surveyed but to be metered
- Technicality of some of the presentation
- Why should meter be paid for when some have it free of charge?
- Can outstanding be paid by instalment
- Can the meters be paid in installment?
- What do you mean by separation of lines?
- How do you meter a market?
- Is it possible to have a 6-7 meters in face me I face you?
- What are you doing about the issues of old/ abandoned meters?
- There are 3 prepaid meter providers, why do you want us to use Mojec

IE's/ Mojec Response

- Customers were enlightened on reason why there could be delay in metering after survey e.g. not quoting ARN number
- Issue of technicality: The BM, COO, Chairman Mojec spoke Yoruba and English intermittently
- On Free Meter: It is government regulation as stipulated by NERC
- Payment of Outstanding: Yes, there is room to pay in instalment and DDR exist to take care of all that
- Separation: Are for face me I face you house require separate bills to apply for meter
- Metering the market: All KYC customers whose payment have been confirmed will be metered by the Mojec metering team
- Is it possible to have a 6-7 meters: Yes, just do a separation and apply for as many meters as you want?
- Old/ abandoned meters: Some them will be evaluated, until it is certified okay otherwise, it is advised to get on through MAP
- On why Mojec was chosen: It was chosen because of their expertise and because of they are a 100% Nigerian company that has a proven track record of excellence.

A. 3 Stakeholder sensitization on IE Plans

- https://punchng.com/ikeja-electric-unveils-electronic-billing-platform/
- https://www.thecable.ng/from-september-ikeja-electric-will-send-your-bill-to-you-as-sms-email
- http://www.ikejaelectric.com/ikeja-electric-introduces-e-bills-to-enhance-customer-experience/
- https://www.thecable.ng/from-september-ikeja-electric-will-send-your-bill-to-you-as-sms-email
- https://www.thisdaylive.com/index.php/2019/08/30/ikeja-electric-kicks-off-metering-in-akowonjo/
- https://theworldnews.net/ng-news/ikeja-electric-kicks-off-metering-in-akowonjo

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- https://theworldnews.net/ng-news/ikeja-electric-kicks-off-metering-in-akowonjo
- https://www.premiumtimesng.com/regional/ssouth-west/349386-ikeja-electric-to-implement-e-billing-by-september.html
- Energy/Ikeja-Electric-introduces-E-Bills-to-enhance-Customer-Experience/46825
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Annex B Timeline

Table 41: Nigerian Electricity Supply Industry Timeline of Transaction and Regulatory Events

Year	Month	Market			MYTO Model in Use					
		Interim Rules - initial period	Interim Rules - Amended	TEM declared but CPs not satisfied	MYTO II Order and Model	MYTO 2.1 Model	MYTO 2.1 Model for TEM (not released)	MYTO 2.1 Model for TEM - 2016 year	MYTO 10 Year Tariff Plan Model	
2012	J									01/06/2012 - start of MYTO II.
	J									31/7/2012 - Privatisation bids submitted.
	A									
	S									
	O									Privatisation bids opened.
	N									
	D									6 Month MYTO Minor Review - no evidence it took place.
2013	J									Privatisation bidder negotiations commenced.
	F									17/02/2013 - signature of Industry documents and payment of 25% of price.
	M									
	A									
	M									
	J									6-month MYTO Review - took place but looked backwards so no tariff change despite huge generation shortfall.
	J									
	A									Signature of Transaction documents & payment of 75% of price.
	S									
	O									
	N									1/11/2013 - Handover.
	D									6-month MYTO Review - no evidence it took place. 04/12/2013 Interim Rules signed.
2014	J									
	F									NERC Letter (17/2/2014) restating Capacity and Energy tariffs and setting Capacity in MWh units.
	M									
	A									
	M									14/05/14 - Revised Interim Rules signed/ 01/05/2014 Fixed Charges Order restricting fixed charges if no power.

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Year	Month	Market: Interim Rules - initial period	Market: Interim Rules - Amended	Market: TEM declared but CPs not satisfied	MYTO Model in Use: MYTO II Order and Model	MYTO Model in Use: MYTO 2.1 Model	MYTO Model in Use: MYTO 2.1 Model for TEM (not released)	MYTO Model in Use: MYTO 2.1 Model for TEM - 2016 year	MYTO Model in Use: MYTO 10 Year Tariff Plan Model	
	J									6-month MYTO Minor Review - wholesale generation prices reduced (and basis changed, consumer tariffs increased for generation).
	J									
	A									
	S									
	O									
	N									CBN in collaboration with the Ministry of Petroleum Resources, Ministry of Power and NERC, signed a MoU for CBN-NEMSF.
	D									6-month MYTO Minor Review - incorporated into the Major Review in Jan 2015.
2015	J									MYTO Major Tariff Review, known as MYTO 2.1. It was assumed in the model that Discos started the Loss Reduction path on 1 January 2013 and were in the third year of their loss reduction path on 1st January 2015.
	F									01/02/2015 Commencement of TEM (Order dated 29/1/2015 and Supplementary Order dated 18th March 2015). CBN-NEMSF disbursement commences.
	M									
	A									01/04/2015 Amended MYTO Tariff Order removing Collection Losses from ATC&C (dated 24/3/2015) - MO/NBET to use PPA prices from MYTO model.
	M									
	J									MYTO Minor Review - did not take place.
	J									Interim Order abolishing Balancing Mechanism (dated 30/07/2015).
	A									
	S									
	O									
	N									
	D									NERC Commissioners 5-year tenure ends and Acting Chairman Appointed.
2016	J									Start of 2016 year in MYTO 2.1 Model, new gas prices and indexation.
	F									Tariff Order and commencement of 10-year Tariff Plan and Model. Model assumed that the first year of loss reduction was 2015, but reduced allowed

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Year	Month	Market			MYTO Model in Use					
		Interim Rules - initial period	Interim Rules - Amended	TEM declared but CPs not satisfied	MYTO II Order and Model	MYTO 2.1 Model	MYTO 2.1 Model for TEM (not released)	MYTO 2.1 Model for TEM - 2016 year	MYTO 10 Year Tariff Plan Model	
										losses by removing Ministries, Departments and Agencies (MDA) debts.
	M									Dramatic drop in generation as a result of gas pipeline attacks, the drop in delivered power means tariffs no longer cover costs.
	A									
	M									Naira weakens and PPA FX indexing means cost of generation jumps from 12 N/kWh to 18 N/kWh with no corresponding increase in end-user tariffs, thus exacerbating the liquidity crisis in the sector.
	J									Minor Review undertaken but results not implemented.
	J									Barrister Toluwani judgement issued against NERC.
	A									Discos begin to lose trust of the sector due to declining performance in % remittances to the market.
	S									CBN constitutes two committees to look at means to address the liquidity problems - proposals for an "NBET Bond" to solve the liquidity crisis are tabled.
	O									Senate instructs that the proposal for the NBET Bond be put on hold until a comprehensive fix developed.
	N									Government turns to World Bank for support in solving the sector liquidity crisis - WB visit Abuja for discussions.
	D									MYTO Minor Review - the 7th since Handover - NERC requests Discos proposals for tariffs but results not implemented. FGN reportedly not wanting tariff increase before 2019 elections.
2017	J									2017 MYTO 10 Year tariffs are implemented by Discos but it is not enough to offset the continued rise in the cost of grid generation - now over 20 N/kWh. CBN Issues a new Foreign Exchange Policy in attempt to close gap between the official rate and parallel market. FGN approves ₦701bn Power Assurance Guarantee for NBET.
	F									
	M									Power Sector Recovery Program – jointly developed by FGN and World Bank. Plan has approved in principle by the FEC but gaps remain.
	A									
	M									Under section 27 of EPSRA the Minister of Power declares 4 categories of Eligible Customers who will

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Year	Month	Market: Interim Rules - initial period	Market: Interim Rules - Amended	Market: TEM declared but CPs not satisfied	MYTO Model in Use: MYTO II Order and Model	MYTO Model in Use: MYTO 2.1 Model	MYTO Model in Use: MYTO 2.1 Model for TEM (not released)	MYTO Model in Use: MYTO 2.1 Model for TEM - 2016 year	MYTO Model in Use: MYTO 10 Year Tariff Plan Model	
										be able to purchase power directly from Successor Gencos and IPPs.
	J									NERC release a Consultation Paper for the Review of MYTO Methodology asking if reviews should become more regular and whether an RDM should be introduced for TCN. MYTO Minor Review - did not take place.
	J									NERC enact the Regulation setting out permit and tariff approval procedures for Mini-Grid Operators.
	A									NERC releases a consultation on Eligible Customers.
	S									
	O									NERC publishes the Eligible Customer Regulations 2017 and 7 Discos declare Force Majeure on grounds of lack of cost reflective tariffs and presence of cross subsidy and in some instances, change of law.
	N									Further details of the ₦701bn PAG facility emerge. Will make up some of the shortfall from Discos remittances to Gencos such that Gencos receive 80% of amounts invoiced.
	D									MYTO Minor Review - undertaken but results delayed.
2018	**J**									NERC orders tariffs to be frozen at 2017 levels - 2018 change not implemented. Publishes Draft Meter Asset Providers (MAP) Regulations 2017 in attempt to close metering gap.
	F									Assisted by World Bank. NERC prepares and circulates guidelines for Performance Improvement Plan an apparent requirement of the "reset" of the NESI.
	M									MYTO Minor Review - NERC presents outcomes of December 2017 Minor Review to Industry but results not implemented.
	A									A Bill to Amend the EPSR Act of 2005 to proscribe and criminalise Estimated Billing proceeds to its 2nd reading in the National Assembly.
	M									Permanent NERC Chairman - James Adeche Momoh - finally appointed, 29 months after previous.
	J									MYTO Minor Review - did not take place.
	J									
	A									
	S									

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Year	Month	Market			MYTO Model in Use					
		Interim Rules - initial period	Interim Rules - Amended	TEM declared but CPs not satisfied	MYTO II Order and Model	MYTO 2.1 Model	MYTO 2.1 Model for TEM (not released)	MYTO 2.1 Model for TEM - 2016 year	MYTO 10 Year Tariff Plan Model	
	O									BPE issued a press statement in October 2018, which clarified that the target date in the Performance Agreements signed with Discos is 31 December 2019.
	N									
	D									MYTO Minor Review - did not take place.
2019	**J**									
	F									
	M									
	A									
	M									NERC issues amended Performance Improvement Plan Guidelines.
	J									MYTO Minor review undertaken but results not implemented in tariffs. Only 2017 and 2018 treated as FM years.
	J									
	A									June minor review tariff orders and minimum remittance percentages published. Tariffs not scheduled to change until January 2020, by which point NERC expects an extraordinary tariff review to have been completed.

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Annex C Demand forecast

The data table forecasting models underlining the Plan must be submitted with the Plan.

C. 1 Customer Forecast

Table 42: Customer Population Projection 2019-2024

Tariff Class	2019	2020	2021	2022	2023	2024
A1SP	14,889	17,904	20,919	23,934	26,949	29,964
A1TP	640	919	1,198	1,477	1,756	2,035
A2	325	372	419	466	513	560
A3	29	45	61	77	93	109
C1SP	115,336	116,208	117,080	117,952	118,824	119,696
C1TP	107,446	139,366	171,286	203,206	235,126	267,046
C2	3,807	3,977	4,147	4,317	4,487	4,657
C3	52	62	72	82	92	102
D1	4,422	5,174	5,926	6,678	7,430	8,182
D2	403	451	499	547	595	643
D3	183	203	223	243	263	283
R2SP	454,038	455,798	457,558	459,318	461,078	462,838
R2TP	303,418	348,350	393,282	438,214	483,146	528,078
R3	437	470	503	536	569	602
R4	7	11	15	19	23	27
S1	158	254	350	446	542	638
Total ('000)	**1,006**	**1,090**	**1,174**	**1,258**	**1,341**	**1,425**
Y-o-Y Growth	10%	8%	8%	7%	7%	6%

C. 2 Demand Forecast

Table 43: Load Forecast 2019-2024

Year	Simultaneous Peak Demand (MW)	Non-Simultaneous Peak Demand (MW)	Energy (GWh)
2019	1,119	1,444	7,474
2020	1,344	1,641	9,109
2021	1,428	1,789	10,042
2022	1,549	1,940	10,974
2023	1,671	2,094	11,907
2024	1,793	2,248	12,840

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C. 3 Estimating Total Load: A Structural Model

In this study, we have applied a *Structural Model* to the time series of load on IE's feeders to estimate the current level of *Unsuppressed Demand*. A common starting point for a Disco energy demand study is to analyse the hour-by-hour loadings on feeders that serve their end-users. Time series data of hourly feeder loads over many days, months or years can be used to build up a picture of the daily, weekly and annual energy demand patterns respectively. The problem faced by Discos in Nigeria is that due to the chronic shortages of power and in some cases unreliability of equipment, feeders are not always energized and so the underlying *unsuppressed* demand is difficult to determine.

To combat this issue of sparseness in the data, we modelled the time series of load of IE's feeders using a "structural model". **The Structural Model approach calculates the unsuppressed demand by forecasting the demand that would otherwise exist on the disconnected feeders if they were connected.**

A structural model assumes that an observable process is composed of several hidden processes plus an observation error. If the observable process is recorded electricity demand, this might be made up of a term representing the likely level of demand at a given time of day and another term representing transient variations in the short-term level of demand. Based on a current estimate of the hidden processes, a forecast for the next value of the observable series can be made. When the true value of the observable series is observed, we use the error of the forecast to update the estimates of the hidden processes according to the Kalman filtering algorithm.

Our structural model is based on methods described in "Time Series Analysis by State Space Methods" (Durbin and Koopman 2012) and is described briefly below.

The structural model is a specific case of the Linear Gaussian State Space Model. The general model can be summarised in matrix form:

Observation equation: $y_t = Z_t\alpha_t + \epsilon_t$

State transition equation: $\alpha_{t+1} = T_t\alpha_t + R_t\eta_t$

Where the observation and state disturbance terms are normally distributed random variables with mean 0 and variance H_t and Q_t respectively, that is:

$$\epsilon_t \sim N(0, H_t) \text{ and } \eta \sim N(0, Q_t)$$

To apply the Kalman filter to a linear, Gaussian state-space model we must define the design matrix Z_t, state transition matrix T_t, selction matrix R_t, observation error covariance matrix H_t and state disturbance covariance matrix Q_t. Note that in the general case the various matrices defining the model at indexed by time because they can have time varying components.

Here we define the state space representation of the structural model that we use to model each feeder.

We define the observed demand on feeder i, $d_{i,t}$ to be the sum of two state variables, $\mu_{i,t}$ and $\gamma_{i,t}$ and a normally distributed error $\epsilon_{i,t} \sim N(0, \sigma_\epsilon^2)$.

$\mu_{i,t}$ is defined to model local trends and occasional shocks to the level of the series using a simple random walk model:

$$\mu_{i,t+1} = \mu_{i,t} + \xi_{i,t}$$

where $\xi_{i,t} \sim N(0, \sigma_\xi^2)$

$\gamma_{i,t}$ models "seasonal" effects that repeat with a period of constant length. We can use frequency domain model for the seasonal component.

The frequency domain approach involves expressing the seasonal component as a sum of trigonometric terms at frequencies $\lambda_j = \frac{2\pi j}{s}$ for $j = 1, \dots, [s/2]$:

$$\gamma_{i,t} = \sum_{j=1}^{[s/2]} \gamma_{i,j,t}$$

where:

$$\gamma_{i,j,t+1} = \gamma_{i,j,t}\cos(\lambda_j) + \gamma_{i,j,t}^{*}\sin(\lambda_j) + \omega_{i,t}$$

$$\gamma_{i,j,t+1}^{*} = -\gamma_{i,j,t}\sin(\lambda_j) + \gamma_{i,j,t}^{*}\cos(\lambda_j) + \omega_{i,t}^{*}$$

$\omega_{i,t} \sim N(0, \sigma_{\omega_i}^2)$ and $\omega_{i,t}^{*} \sim N(0, \sigma_{\omega_i^{*}}^2)$

If the full range of frequencies is included then the frequency domain model is identical to the time domain model, however it is possible to drop some of the frequencies to obtain a more parsimonious model for complex seasonal patterns. We find that including seasonal frequencies at $j = 1, \dots, 5$ for 24-hour period is sufficient to model the important periodic effects in IE's data. Longer term periodic effects such as weekly and wet/dry season effects will be captured by shifts in the value of $\mu_{i,t}$.

Putting this all together we get the observation equation:

$$d_{i,t} = \mu_{i,t} + \gamma_{i,t} + \epsilon_{i,t}$$

And the following transition equations:

$$\mu_{i,t+1} = \mu_{i,t} + \xi_{i,t}$$

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$$\gamma_{i,t} = \sum_{j=1}^{[s/2]} \gamma_{i,j,t}$$

$$\gamma_{i,j,t+1} = \gamma_{i,j,t}\cos(\lambda_j) + \gamma^*_{i,j,t}\sin(\lambda_j) + \omega_{i,j,t}$$

$$\gamma^*_{i,j,t+1} = -\gamma_{i,j,t}\sin(\lambda_j) + \gamma^*_{i,j,t}\cos(\lambda_j) + \omega^*_{i,j,t}$$

and $\epsilon_t \sim N(0, \sigma^2_\epsilon)$, $\xi_t \sim N(0, \sigma^2_\xi)$, $\omega_t \sim N(0, \sigma^2_\omega)$ and $\omega^*_{i,j,t} \sim N(0, \sigma^2_{\omega^*_j})$

The matrix form of the basic structural model is well known and is documented, for example, in (Durbin and Koopman 2012).

The structural model provides a method for handling missing data in a similar way: where there is missing data, ϵ_t is estimated by 0.

Structural Models are a well-established time series modelling technique and are favoured in many applications for their robustness and transparency. The method has been widely applied to short term electricity demand forecasting.

C. 4 Estimating Total Load: A Dynamic Model

The dynamic regression model is applied to each feeder on the IE network to generate its hourly demand using the hourly regression coefficients, for each customer tariff category generated in the baseline year (2019). This methodology assumes a constant level of customer electrical appliance ownership over the forecast period, which is reasonable given the unresponsive relationship between GDP and electricity demand in Nigeria given the poor historical supply of on-grid energy. Essentially it looks at the temporal relationship between customers on a feeder and the feeders' hourly demand in the baseline year, to project the demand of feeder for the same period in future years.

For every hour in our dataset we can add together the demand on every feeder that is connected to get the total suppressed demand. We can also add together the number of customers on each connected feeder to get the total number of connected customers.

We can then fit a model that predicts the suppressed demand based on the number of connected customers. However, the relationship between demand and the number of customers connected varies over time. Several patterns of variation can be observed. Over each day the average level of demand per customer follows a relatively consistent pattern. Transitory effects like weather events cause variation in the level of demand per customer on a short timescale. Variation on an annual timescale is caused by seasonal effects.

To model this time varying dependency of demand on the number of connected customers we use a dynamic regression model. The dynamic regression model is a linear regression model expressing how demand depends on the number of customers connected in each hour of the dataset. The model is dynamic because the regression coefficients vary over time.

It is not practical to include the full list of MYTO tariff categories as customer categories in the model. This is because increasing the number of categories increases the number of parameters that we need to estimate. This becomes computationally difficult with more categories and creates a risk of "over-fitting". "Over-fitting" will cause errors when we generalize the model to feeders that were not used to estimate the model. Therefore, it is helpful to group customers into 3 categories: residential *R*, small commercial *SC*, medium commercial *MC* and large commercial *LC*. Category *R* includes MYTO tariff classes R2SP, R2TP, R3, R4 and S. Category *SC* includes tariff classes C1SP, C1TP, D1, A1TP and A1SP. Category *MC* includes tariff classes A2, C2 and D2. Category *LC* includes tariff classes A3, C3 and D3. Alternative categorizations are possible. For example, we tried grouping customers by top level MYTO category: R, C, D, A, S. However, we selected the categorization that has the highest predictive power (according to the Mean Absolute Percentage Error statistic). This categorization accounts for two major differences between customer consumption patterns: (1) residential customers behave differently to other customers; (2) commercial/industrial/special customers are highly differentiated by size.

We use the Kalman Filter algorithm implemented in the python package StatsModels to build the model. This approach can be used to infer the level of demand that we would expect to be realized at any time on feeders without demand data.

In order to formally describe the model, let us define d_t to denote the total demand from all feeders connected at time t and let $\mu_{x,t}$ denote the proportion of customers of type *x* that are connected at time *t*. Our model is then given by the equations:

$$d_t = \beta_{R,t} n_{R,t} + \beta_{C1,t} n_{C1,t} + \beta_{C2,t} n_{C2,t} + \epsilon_t$$

$$\beta_{x,t} = \mu_{x,t} + \gamma_{x,t},\ \forall x \in \{R, SC, MC, LC\}$$

$$\mu_{x,t} = \mu_{x,t-1} + \eta_{x,t}$$

$$\gamma_{x,t} = \sum_{j=1}^{[s/2]} \gamma_{j,x,t}$$

where:

$$\gamma_{j,x,t+1} = \gamma_{j,x,t} \cos(\lambda_j) + \gamma^*_{j,x,t} \sin(\lambda_j) + \omega_{j,x,t}$$

$$\gamma^*_{j,x,t+1} = -\gamma_{j,x,t} \sin(\lambda_j) + \gamma^*_{j,x,t} \cos(\lambda_j) + \omega_{j,x,t}$$

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Annex D Financial Analysis Assumptions

D. 1 Energy and capacity costs

The capacity and energy charges for the period 2020-2024 are based on the June 2019 MYTO Minor Review Model in nominal terms.

D. 2 Input data

The expected energy and capacity levels to be borne by Discos are shown in 2019 real terms in Table 44.

Table 44: Expected generation costs for the industry and Ikeja Electric in nominal terms

	Current[4]	2020	2021	2022	2023	2024
National energy delivered to Ikeja Electric (MWh/month)	315	487	532	592	639	676
Overall charge for delivered energy (N/kWh delivered)	22.43	27.45	27.54	27.71	27.88	28.07
Average energy tariff (N/kWh delivered)	11.05	10.41	10.48	10.56	10.65	10.73
Average capacity tariff (N/kWh available)	8.50	8.98	8.99	9.04	9.08	9.14

D. 3 Inflation in cost base

In all scenarios, we have applied inflation to operational costs consistent with NERC's June 2019 Minor Review.

[4] NBET invoices for June 2019

The regulatory asset base and CAPEX are inflated in the MYTO model by foreign exchange only. Since the June 2019 Minor Review assumed no change in foreign exchange, this means that the regulatory asset base only increases by CAPEX minus depreciation.

Note that this is an issue with the MYTO model, as US inflation should also be applied to the regulatory asset base to keep the investor whole in real terms.

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Annex E Achievements

E. 1 HSE Engagements

Table 45: Historical Annual Safety Trainings

Year	Name of Training	Details of each named Training
2014	Working and Managing Safely	This training held in October and November 2014. It involved Commercial, Technical, NAPTIN Graduates, and other staff on the fundamentals of Safety as it relates to their Job Functions. 773 staff were engaged in the first batch and 791 in the second batch companywide
	Driving Safely (I ARRIVE ALIVE)	This training held in 15th and 22nd November 2014. 137 Drivers were inducted on the Golden Rules of Driving.
	Contractors Safety Forum	This training held in 13th November 2014. 84 Participants were in attendance Over 90% of the Contractors were represented by their MDs/CEOs and Senior Management Team were in attendance.
	Driving Safely (I ARRIVE ALIVE)	In July 2015, 137 Drivers were inducted on the Golden Rules of Driving enhance defensive driving and operational excellence.
		30 newly recruited Drivers were also engaged on the 6th of August, 2015
	Operational Safety	81 Distribution Substation Operators (DSO) were trained on Operational Safety and PTW System in July 2015.
	Technical Safety and Injury Prevention Engagement	1,061 Technical Staff were engaged companywide in August and September 2015 where LFIs and Accident prevention strategies were discussed.
	Working Safely with PCB	Technical Safety & Environmental Learning Sessions on safe handling of PCB conducted in the Business Units in April 2015 where 75 Technical Staff were engaged.
2015	Contractors Safety Management	950 AMI Installers Subcontractors' Senior Management Team trained on "Working and Managing Safely" from April till December 2015.
		2nd Contractor Safety Forum attended by 48 Top Management Staff of Ikeja Electric's Contractors on the 28th of April 2015 to further create more awareness on Occupational Health and Safety culture in line with the directive of International Labour Organisation (ILO)

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Year	Name of Training	Details of each named Training
		50 Management Team of IE and NIPP Contractors engaged on “Achieving Safety Milestones in Projects Execution” using NERC Health & Safety Code IE Safety Code (Safety Non-negotiable) on the 14th of September 2015
		188 Contractors’ Technical Crew passed through HSE Orientation Programme titled “Working Safely within IE Network” on the 16th of September, 2015
		94 Site personnel working on Oshodi Building Project engaged on Construction Safety and Hazards Management in October, 2015
		59 CETAAM Project Team members (including KEPCO) trained on “Achieving Excellent Safety Culture” in CETAAM Project in September 2015.
	Cleaning Safely & Basic Hygiene	22 Housekeepers/Janitors were engaged on the 24th of June 2015.
2016	Safety Competence Intervention Programmes	926 Contractors Personnel underwent HSE Induction before commencing their assigned projects.
		1052 Technical Staff were engaged on Accident Presentation Tools
		577 Energy Sales Representatives were engaged on "Achieving Sales Target Safely"
		66 Operations and Maintenance Staff, 100 Cable Jointers, 549 Linesmen, 13 MDMM Staff, 41 Vigilance Team were engaged "Elimination of Accidents"
		212 Distribution Substation Operators were engaged on Operation Safety. The Implementation of Permit to Work Procedures.
		224 Drivers were trained on "Drive Safe, Home Safe"
2017	Safety Competence Intervention Programmes	1039 Contractors Personnel underwent HSE Induction before commencing their assigned projects.
		84 LECAN Members were trained
		Over 1200 staff were engaged during the Biannual Technical Safety and Injury Prevention Program tagged “Beyond Zero -Take Ownership” which was held companywide across the Business Units and Corporate Headquarters.
		216 drivers were engaged on “Golden Rules for Safe Driving and Driving Safely in the Wet Season” and “Drive Safe, Home Safe “during Safety and Defensive Driving Programme.
		74 staff of Commercial Department and Vigilance Strategy and Loss Reduction Unit were trained in two batches on “Detecting Energy Theft Safely”

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Year	Name of Training	Details of each named Training
	Technical Safety Leadership Interactive Forum	53 Undertaking Managers and 69 Technical Leaders (Operations and Maintenance Coordinators, Operations & Maintenance Specialists, Project and Works Team Leads)
	BE A LIFE SAVER	145 nominated Emergency Responders under companywide passed through “Be a Life Saver”; A practical approach to First Aid at Work.
2018	Safety Competence Intervention Programmes	2587 Contractors Personnel underwent HSE Induction before commencing their assigned projects.
		153 Contractor/ Vendor Trained in the Contractor Competence Course
		78 Technical Leaders Engaged during the Technical Safety Discourse
		1958 Staff were engaged during the Target Zero Learning Sessions that held across the Business Units.
		187 Drivers underwent "Home Safe, Drive Safe" within the year
		263 Energy Sales Representatives and Direct Energy Agents underwent a trained tagged "Achieving Sales Target Safely"
		142 Security Personnel Engaged Fire Safety and Emergency Response Training
	Technical Safety Discourse	264 Distribution Substation Operators (DSOs), 26 Corporate Headquarters’ Technical Staff and 479 Outsourced Personnel, 184 Drivers and 14 Operations and Maintenance Coordinators, Supervisors and Officers were engaged with a Focus on “Mission Zero-Take Ownership” Strategy tagged “Achieving the Zeros in 2019” in January, 2019.
		875 participants in attendance at the 1st Technical Safety Village Meeting in February and May 2019
H1 2019	Safety Competence Intervention Programmes	57 nominated passed through Internal IMS Certification Programme in March 2019.
		60 Staff nominated across the Company underwent a 1-day Practical First Aid Training themed ‘Be a Life Saver’ in April 2019.
		151 Security Personnel across Ikeja, Oshodi Ikorodu and Shomolu Business Units were trained on “Fire Safety and Emergency Response Management”.
		14 Staff comprising of ESRs/ERs/PMSs were trained on “Achieving Sales Target Safely” during the Foundational Energy Business Knowledge Training Programme for New Commercial Staff

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Year	Name of Training	Details of each named Training
		20 newly hired Cable Jointers and Fitters were trained on "Working Safely, Eliminating Accidents" during the Foundational Cable Jointers Training.
		474 Technical Staff, Technical Leadership of Abule Egba, Akowonjo and Ikorodu Business Units attended the Emergency Technical Safety Village Meeting (1st Batch).
		88 Drivers were trained on "Home Safe, Drive Safe" within January to June 2019.

Table 46: Historical Community engagement and safety trainings

Year	Name of Training	Details of each named Training
2016	Public Safety Sensitization	7 Communities (CDAs and CDCs) were engaged within the year in conjunction with Corporate Communications Department during Community CDA Meetings.
2017	Public Safety Sensitization	36 Communities (CDAs and CDCs) were engaged within the year in conjunction with Corporate Communications Department during Community CDA Meetings.
		6 Students Programme on "Electricity & YOU" organised in primary schools in collaboration with the Corporate Communications Department
2018	Public Safety Sensitization	40 Communities (CDAs and CDCs) were engaged within the year in conjunction with Corporate Communications Department during Community CDA Meetings.
		1 Public Corporate Social Responsibility Session tagged 'Electricity and You' for Students
2019	Public Safety Sensitization	83 Communities (CDAs and CDCs) were engaged from January till June 2019 in conjunction with External Communications Department

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Year	Name of Training	Details of each named Training
		during Community CDA Meetings, for Houses encroaching Lines and during Customer Fair Programmes.

E. 2 Security Achievements

Table 47: Historical Security Achievements

Year	Achievements	Challenges
2014	1. Setting out security policies and procedures from outcomes of our threat /risk analysis to the business and enforcement of same. 2. Security liaison with Government security agencies. 3. Installation of physical security measures to enhance security in some facility. 4. Routine security awareness campaign for staff	1. Lack of sufficient manpower to kick start the unit. 2. Lack of understanding of the operations of IE by security agencies. 3.Customers hostilities
2015	1. Increase in numbers of procedures and processes to enhance security of men and facility. 2. Approval to use armed personnel for protective functions. 3. Donation of vehicle to security agencies to enhance IE patrol/response function. 4. Arrest of vandals. 5. No major security incident recorded	1. Customers hostilities. 2. Inimical activities of former NEPA/PHCN staff.
2016	1. Risk assessment of all business locations and deployment of solutions. 2. Donation of vehicle to the police to support IE security operations. 3. Setting up of security command center to coordinate security operations across the network. 4. Improvement in staff security awareness campaign against assault and other work-related risks. 5. Installation of electronic security systems at Oshodi and Ikeja Business Units	1. Customers hostilities and activities of ex NEPA staff.

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Year	Achievements	Challenges
2017	1. Decentralization of security roles and functions and recruitment of personnel to cover security of the 6 BUs 2. Intensive campaign on security against staff assaults. 3.Successfully hosted Ministerial sectorial meeting. 4. Introduction of staff in-house skill development training programs. 5. Introduction of mandatory management performance review (MPR) for field personnel. 6. Police approval to accord promptness to IE security related issues.	1. Activities of rogue security personnel and customers
2018	1. Community enlightenment against assault of personnel and sabotage against IE installations. 2. Introduction of more processes and procedures including managing increased rates of customers protests etc. 3. Arrest and prosecution of assaulters and vandals of assets. 4. Enhanced support to both technical and commercial units. 5. Patrol of network against energy thefts. 6. Training of third-party personnel-guards. 7. Security Command center restructured to run 24/7 operations. 8. Enhanced working relationship between security, legal and corporate communications.	1. Activities of some field staff who compromised with customers. 2. Inadequate support by communities in protecting assets located in their domain
2019	1. Restructuring of the unit to pragmatically harness and address the security concerns in view of increasing business expansion and activities. 2. Recruitment of more field personnel to the BUs and Command center. 3. Deployment of dedicated Armed Response Team to support field operations. 4. Uncover control lapses in movement of items. 5. Use of third-party experts to train field operations staff on self-protection in view of increase in incidences of assault. 6. Introduction of physical barriers to support managing irate protesters.	1. Lack of sufficient support from NPF in determining charges against criminals who undermine IE business.

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Year	Achievements	Challenges
	7. Arrest and prosecution of criminals. 8. Enhanced relationship with security agencies. 9. Reduction in the rate of staff assault of vandalism of critical assets.	

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Annex F IE Cost Efficiency Data

F. 1 Procurement Details for Mangoro Injection Substation

IKEJA ELECTRIC

: http//www.ikejaelectric.com

Ref: IE/23/PROC/WO/0497/2019

Obafemi Awolowo Way,
Alausa, P.M.B. 21818,
Ikeja, Lagos.
Date: Friday, August 2, 2019

The Managing Director;
Inlaks Power Solutions Ltd.,
1, Alhaji Adejumo Avenue,
Oshodi Expressway, Ilupeju,
Lagos.

Dear Sir,

OFFICIAL WORKS ORDER FOR THE SUPPLY OF 1SET OF ABB 5 BOARD PANEL FOR REPLACEMENT AT MANGORO 1 X 15MVA INJECTION SUBSTATION

Ikeja Electric Plc is pleased to inform you that you have been awarded the contract for the supply of 1Set of ABB Board Panel for replacement at Mangoro 1 X 15MVA Injection Substation.

The total cost of the contract is Twenty Five Million, Nine Hundred and Thirty Five Thousand Naira (₦25,935,000.00) only, inclusive of 5% VAT.

The details of the contract price are:

S/N	Description	Unit	Qty	Unit Price (N)	Total (N)
1	ABB, 5Board Panel - 11kV, 25kA Indoor Switchgear panels with ABB VD4 breaker, ABB relays REF 615C, 1,250A incomer – 1No, 630A outgoing – 4No.	Set	1	24,700,000.00	24,700,000.0
	5% VAT				1, 235,000.0
	TOTAL				25,935,000.0

1.0 COMPLETION PERIOD

This supply must be satisfactorily completed within Twelve (12) weeks of your signing this Official Works Order.

2.0 LIABILITY

This Works Order shall remain firm and under no circumstances shall the Company entertain any escalat of prices except for agreed variation in quantities as might be directed by the Company.

IE PLC reserves the right to reject the goods after supply if found to be defective or badly completed, cost of replacing the defective shall be charged against you.

3.0 GUARANTEE PERIOD

The Supplier shall also give a minimum warranty period of twelve (12) calendar months from the date of commissioning to service, during which any noticeable defects in the goods supplied by you shall be rectified at no extra cost to the company.

Doc. No: IE/SC/015 Revision No:

4.0 INSPECTION

This supply must be satisfactorily completed within Twelve (12) weeks of your signing this Official Works Order.
There shall also be Company's acceptance and certification of quality of supply done before invoices be honoured.

5.0 PAYMENT

Payment will be effected on the following terms:

5.1 The entire cost of the contract less Withholding Tax will be paid on completion of the contract, certificat by the QA/QC Team, Ikeja Electric Plc and receipt of final invoice.

5.2 The Supplier is to remit the 5% VAT to the nearest VAT office and return evidence of remittance to IE PLC

6.0 AUTHENTIFICATION OF OFFICIAL WORKS ORDER

Please acknowledge your acceptance of this works order by signing and returning all copies of this docum to this office.

Yours Faithfully,

DR. ANTHONY YOUDEOWEI
CHIEF EXECUTIVE OFFICER
IKEJA ELECTRIC PLC

SIGNED BY: ....
HEAD TECHNICAL OPERATIONS
ON BEHALF OF IE PLC

DATE: 5/8/19

SIGNED BY: ....
INLAKS POWER SOLUTIONS LTD.

DATE: 05/8/19

SIGNED BY: .... Pravin Suryawanshi
WITNESS

DATE: 05/08/19

Doc. No: IE/SC/015 Revision No:

Authority to Procure

IE/23/PROC/ATP/..0149../201..9.

Transaction Title:	5Board Panel for Mangoro	Staff Name:	Edward Onuminya
Details Outline:	5Board Panel for Mangoro	Staff Department:	Technical Services
Scope Of Work:	5Board Panel for Mangoro	Item Owner:	Technical Services
Quantity Required:	1		

Departmental Budget Information

Annual Budget: 740,470,450

Expense To Date: 156,058,316

Balance: 584,412,134

PROCUREMENT ITEMS

Item No	*Item Name*	*Qty*	*Unit of Measurement*	*Brand Name*	*Specification*
1	11kV indoor switch gear pa...	1	Set	ABB	11KV INDOOR SWITCH GEAR PANELS AND BRE/ MAKE: ABB

Insert item

Extra Budgetary Form

Click here to attach a file

Bill Of Quantity(BOQ)

Click here to attach a file

Attached Quotes

- 5Board Panel Inlak.pdf 743.33 KB
- 5Board Panel Okolison.pdf 369.21 KB
- 5Board Panel Bolamark.jpg 71.53 KB
- 5Board Panel Koby.pdf 541.53 KB
- 5Board Panel O Secul.pdf 139.1 KB
- 5Board Panel Enfrasco.pdf 568.2 KB

Vendors Quote

Item Name	*Qty*	*Vendor Name*	*Unit Price*	*Total Price*	*Grand Total (VAT Inclusive)*	*Delivery Period*	*Recoi Ve*
5Board Panel	1	Inlaks Power Solution Ltd.	24,700,000	24,700,000	25,935,000	12weeks	Yes
5Board Panel	1	Okolison Brothers Nig. Ltd	25,700,000	25,700,000	26,985,000	12weeks	No
5Board Panel	1	Bolamark Engr. Ltd.	32,000,000	32,000,000	33,600,000	2weeks	No
5Board Panel	1	Koby Global Engr. Services...	39,055,000	39,055,000	41,007,750	4days	No
5Board Panel	1	Enfrasco Energy & Infra Se...	40,194,000	40,194,000	42,203,700	6days	No
5Board Panel	1	JNJ MArine Engr. & Shippi...	35,500,000	35,500,000	37,275,000	2weeks	No
5Board Panel	1	O Secul Nig. Ltd.	33,600,000	33,600,000	35,280,000	4weeks	No

Insert item

Vendor Name	*Total Cost*
Inlaks Power Solution Ltd.	25,935,000

Insert item

Total Actual Cost: 25,935,000

F. 2 Procurement Details for Adiyan 11kV feeder extension

IKEJA ELECTRIC

Website: http//www.ikejaelectric.com

Ref: IE/23/PROC/WO/0418/2019

Company Head-quarters
Obafemi Awolowo Way,
Alausa, P.M.B. 21818,
Ikeja, Lagos.
Date: Monday, July 15, 2019

The Managing Director;
Ulasbery & Company Ltd.,
11B, Adeshina Street,
Off Ezekiel Street, Ikeja,
Lagos.

Dear Sir,

OFFICIAL WORKS ORDER FOR THE SUPPLY OF MATERIALS AND EXTENSION OF ADIYAN 11KV FEEDER FROM PASTOR OLADIMEJI SUBSTATION TO ITOKIN TO RELIEVE IJOKO ROAD 11KV FEEDER SUBSTATION, ADIYAN UNDERTAKING, ABULE EGBA BUSINESS UNIT

Ikeja Electric Plc is pleased to inform you that you have been awarded the contract for the supply of materials and extension of Adiyan 11kV Feeder from pastor Oladimeji Substation to Itokin to relieve Ijoko road 11kV Feeder Substation, Adiyan Undertaking, Abule Egba Business Unit.

The total cost of the contract is Eleven Million, Seven Hundred and One Thousand, Five Hundred and Eleven Naira, Eighty Five Kobo (₦11,701,511.85) only, inclusive of 5% VAT.

The details of the cost are as contained in the attached schedule which forms part of the Official Works Order.

S/N	Description	Unit	Qty	Unit Price (N)	Total (N)
1	Supply of Materials	Lot	1	9,968,717.00	9,968,717.00
2	Labour	Lot	1	1,175,580.00	1,175,580.00
	Sub Total				11,144,297.00
	5% VAT				557,214.85
	TOTAL				11,701,511.85

1.0 COMPLETION PERIOD

This work must be satisfactorily completed within Two (2) weeks of your signing this Official Works Order and completion of the safety induction.

2.0 LIABILITY

This Works Order shall remain firm and under no circumstances shall the Company entertain any escalatio of prices except for agreed variation in quantities as might be directed by the Company.

IE PLC reserves the right to reject the goods after supply if found to be defective or badly completed, th cost of replacing the defective shall be charged against you.

Contractor will be held liable for the safety of men and equipment during the course of the project. All workers (must attend safety induction within 48 hours of works order collection and report to site latest 24 hours after induction) on site must always be fully clothed in Personal Protective Gear.

Doc. No: IE/SC/015 Revision No: 0

3.0 GUARANTEE PERIOD

The Contractor shall also give a minimum warranty period of twelve (12) calendar months from the date c commissioning to service, during which any noticeable defects in the goods supplied by you shall be rectified at no extra cost to the company.

4.0 INSPECTION:

This work must be satisfactorily completed within Two (2) weeks of your signing this Official Works Order. There shall also be Company's acceptance and certification of quality of supply done before invoices be honoured for payment.

5.0 PAYMENT:

Payment will be effected on the following terms;

5.1 The entire cost of the contract less Withholding Tax will be paid as below;

5.2 30% (advance payment) of the contract sum will be paid on provision of Advance Payment Guarantee (AP(from a reputable bank.

5.3 70% balance of payment will be made on completion of the contract, certification by the Technical Tear Ikeja Electric Plc, Ikeja Electric Plc and receipt of final invoice

5.4 The Supplier is to remit the 5% VAT to the nearest VAT office and return evidence of remittance to IE PLC.

6.0 AUTHENTIFICATION OF OFFICIAL WORKS ORDER

Please acknowledge your acceptance of this works order by signing and returning all copies of th document to this office.

Yours faithfully,

DR. ANTHONY YOUDEOWEI
CHIEF EXECUTIVE OFFICER
IKEJA ELECTRIC PLC

SIGNED BY: ....
HEAD TECHNICAL OPERATIONS
ON BEHALF OF IE PLC

DATE: 16/7/19

SIGNED BY: ....
ULASBERY & COMPANY LTD.

DATE: 15/7/19

SIGNED BY: Anucho Nwenelo · P
WITNESS

DATE: 15/7/19

Doc. No: IE/SC/015 Revision No: 0

OLADIMEJI S/S TO ITOKIN TO RELIEVE IJOKO ROAD 11KV FEEDER. S/S.ADIYAN U/T, ABULE EGBA BUSINESS UNIT.

S/No	Description	Required		VALUE	
		Quantity	Unit	Unit	Total
1	Galvanised Earth rod	10	No	2,340.00	23,400.00
2	70mm² Cu earth wire	150	Mtrs	2,340.00	351,000.00
3	70mm² Cable Socket	30	No	360.00	10,800.00
4	150mm² Aluminium Line tap	36	No	900.00	32,400.00
5	10.06m Concrete pole	56	No	43,743.25	2,449,622.00
6	4"x3" (6 feet)Channel Iron	20	No	8,775.00	175,500.00
7	Stay Wire	405	Mtrs	180.00	72,900.00
8	Stay Block	27	No	450.00	12,150.00
9	Stay Insulator	27	No	450.00	12,150.00
10	Stay Rod	27	No	4,095.00	110,565.00
11	J - Hook	60	No	585.00	35,100.00
12	6 - Bolt Clamp	60	No	2,565.00	153,900.00
13	Adaptor Socket	60	No	585.00	35,100.00
14	11kV Silicon Disc Insulator	60	No	4,455.00	267,300.00
15	11kV Fibre Cross Arms (complete with accessories)	40	No	7,605.00	304,200.00
16	11kV Silicon Pin Insulator	120	No	4,590.00	550,800.00
17	150mm² Aluminum Conductor	6,900	Mtrs	765.00	5,278,500.00
18	5/8 x 2 bolt & nut	10	No	180.00	1,800.00
19	5/8 X 6 Bolt & Nut	80	No	225.00	18,000.00
20	5/8 x 8 bolt & nut	50	No	243.00	12,150.00
21	5/8 X 9 Bolt & Nut	20	No	261.00	5,220.00
22	5/8 X 10 Bolt & Nut	60	No	315.00	18,900.00
23	5/8 X 11 Bolt & Nut	20	No	360.00	7,200.00
24	5/8 X 12 Bolt & Nut	10	No	360.00	3,600.00
25	5/8 Galvanized washer	420	No	63.00	26,460.00
	Sub Total				9,968,717.00
	VAT				498,435.85
	Total				10,467,152.85

OLADIMEJI S/S TO ITOKIN TO RELIEVE IJOKO ROAD 11KV FEEDER. S/S.ADIYAN U/T, ABULE EGBA BUSINESS UNIT.

S/No	Description	Quantity		Unit Price (N)	Amount (N)
		Qty	Unit		
1	Surveying and pegging	1	Lot	21,600.00	21,600.00
2	Digging of holes for Poles	56	No	2,520.00	141,120.00
3	Digging of holes for Stay	27	No	1,800.00	48,600.00
4	Erection of Pole	56	No	2,160.00	120,960.00
5	Beaming of Poles	56	No	3,600.00	201,600.00
6	Weaving of stay	27	No	2,700.00	72,900.00
7	Drilling of Channel iron	20	No	2,700.00	54,000.00
8	Dressing of poles	56	No	2,700.00	151,200.00
9	Stringing of lines	46	Span	3,600.00	165,600.00
10	Cutting of trees	1	Lot	180,000.00	180,000.00
11	Earthing of Lines.	1	Lot	18,000.00	18,000.00
	Sub Total				1,175,580.00
	VAT				58,779.00
	Total				1,234,359.00

Authority to Procure
IE/23/PROC/ATP/0388/2019

Transaction Title:	Extension of Adiyan 11kV F	Staff Name:	Onyinyechukwu Anene-Nzelu
Details Outline:	Extension of Adiyan 11kV F	Staff Department:	Technical Services
Scope Of Work:	Construction	Item Owner:	ABULE EGBA
Quantity Required:	1		

Departmental Budget Information

Annual Budget: 2,243,151,151
Expense To Date:
Balance: 2,243,151,151

PROCUREMENT ITEMS

Item No	*Item Name*	*Qty*	*Unit of Measurement*	*Brand Name*	*Specification*
1	Extension of Adiyan 11kV Fee	1	No	Extension of Adiyan 11kV Feeder	Extension of Adiyan 11kV Feeder

Insert item

Extra Budgetary Form

Click here to attach a file

Bill Of Quantity(BOQ)

Click here to attach a file

Attached Quotes

- Adiyan project-Ulasbery.pdf 130.65 KB
- Ikeja Network Expansion Project Adiya Material - Graceforte.pdf 269.44 KB
- Adiyan- Limencee.xlsx 27.68 KB
- BILLARD ENGINEERING.docx 816.15 KB
- INTERNATIONAL ENERGY SERVICES LIMITED QUOTE 1.xlsx 95.25 KB
- REQUEST FOR QUOTE - Network Expansion Projects PRICED BOQ.xlsx 97.85 KB

Vendors Quote

Item Name	*Qty*	*Vendor Name*	*Unit Price*	*Total Price*	*Vat Inclusive*	*Grand Total (VAT Inclusive)*	*Delivery Period*	*Re*
Extension of Adiyan 11k	1	SCM Benchmark	14,123,565	14,123,565	Select...	14,829,743.25	4weeks	N
Extension of Adiyan 11k	1	Ulasbery & Company Ltd	11,144,296.733	11,144,296.733	Yes	11,701,511.56965	2 weeks	Y
Extension of Adiyan 11k	1	Gosslink Engineering Ltd	14,121,901.24	14,121,901.24	Yes	14,827,996.302	3weeks	N
Extension of Adiyan 11k	1	Limencee Nig Ltd	16,462,450	16,462,450	Yes	17,285,572.5	6weeks	N
Extension of Adiyan 11k	1	Milan Continental	17,211,845	17,211,845	Yes	18,072,437.25	4weeks	N
Extension of Adiyan 11k	1	International Energy Services Lt	13,824,645.24	13,824,645.24	Yes	14,515,877.502	4weeks	N
Extension of Adiyan 11k	1	Graceforte Business Links Ltd	11,197,360.25	11,197,360.25	Yes	11,757,228.2625	3weeks	N
Extension of Adiyan 11k	1	Billiard Properties & Engineering	25,552,767.72	25,552,767.72	Yes	26,830,406.106	5weeks	N
Extension of Adiyan 11k	1	Beam Energy Ltd	21,049,560	21,049,560	Yes	22,102,038	4weeks	N
Extension of Adiyan 11k	1	Interlinked Technologies	16,912,654.3	16,912,654.3	Yes	17,758,287.015	4weeks	N
Extension of Adiyan 11k	1	Kenol Nigeria Ltd	22,730,975	22,730,975	Yes	23,867,523.75	5weeks	N
Extension of Adiyan 11k	1	CovenantPlus Engineering Ltd	15,693,625	15,693,625	Yes	16,478,306.25	4weeks	N

Annex G Distribution Network Investments

Project Description	Project Type	Unit Cost (Naira Mill)	Quantity	Cost (Naira Mill)	Investment Year
Existing 1x15MVA while additional 1x15MVA 33/11kV is required at Alapere ISS	P&C	220.09	1	220.09	2020
Exiting is 2x15MVA while the additional 1x15MVA 33/11kV is required at Odogunyan ISS	P&C	220.09	1	220.09	2020
To replace existing 1x2.5MVA transformer with 1x15MVA 33/11kV Injection Substation at Ilapo (Complete replacement of new substation)	P&C	220.09	1	220.09	2020
Existing 1x15MVA while additional 1x15MVA 33/11kV is required at New Oworo ISS	P&C	220.09	1	220.09	2020
Existing 1x7.5MVA to be replaced with 1x15mvA 33/11 at Alaja	P&C	115.74	1	115.74	2020
Existing 1x15MVA while additional 1x15MVA 33/11kV is required at Opebi ISS	P&C	272.28	1	272.28	2020
1x15MVA 33/11kV Injection substation at Ipakodo	P&C	220.09	1	220.09	2021
1x15MVA 33/11kV Injection Substation at Laspotech	P&C	252.54	1	252.54	2020
1x15MVA 33/11kV Injection Substation at Pedro	P&C	399.7	1	399.70	2020
1x2.5 MVA 33/11kV Injection Substation at TA Gardens	P&C	70	1	70.00	2021
1x15MVA 33/11kV Injection Substation at Abule Ijoko	P&C	493.65	1	493.65	2020
2x15MVA Injection Substation at Agbede	P&C	475.63	1	475.63	2021
1x15MVA 33/11kV Injection substation at Pako	P&C	753.98	1	753.98	2021
1x15MVA 33/11kV Injection substation at Obadore	P&C	308.88	1	308.88	2021
1x15MVA 33/11kV Injection substation at Isheri Oshun	P&C	283.58	1	283.58	2021
1x15MVA 33/11kV Injection substation at Baruwa	P&C	490.6	1	490.60	2023
1x15MVA 33/11kV Injection substation at Ijedodo	P&C	414.05	1	414.05	2021
1x15MVA 33/11kV Injection substation at Agiliti	P&C	371.11	1	371.11	2021
1x15MVA 33/11kV Injection substation at Olorunnisola	P&C	414.05	1	414.05	2021
1x15MVA 33/11kV Injection substation at Pipeline	P&C	361.65	1	361.65	2021
Proposed Koloba 11kV feeder Ex-ALAJA 1X15MVA ISS	P&C	20.73	1	20.73	2020
Proposed Wole Omo-Osho 11kV feeder Ex-Alimosho 1X15MVA ISS	P&C	19.63	1	19.63	2020

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Proposed Conversion of Kuwait 11kV feeder from underground to overhead	P&C	18.06	1	18.06	2020
Proposed Relief of Walter Anderm 11kV feeder with Bode Williams and Olota feeders	P&C	4.87	1	4.87	2020
Proposed radiation Surulere 11kV feed Ex-Amikanle	P&C	17.27	1	17.27	2020
RADIATION OF 33kV FEEDER FROM ODOGUNYAN TS TO ADAMO ENVIRON	P&C	57.97	1	57.97	2020
COMPREHENSIVE REHABILITATION ON AGBOWA 33kV FEEDER	P&C	58.87	1	58.87	2020
REHABILITATION OF IBESE 33kV FEEDER	P&C	8.86	1	8.86	2020
REPLACEMENT OF OBSELETE 11kV PANEL AT SABO T1 15MVA	P&C	42	1	42.00	2020
REPLACEMENT OF OBSELETE 11kV PANEL AT ODOGUNYAN T1 15MVA.	P&C	28	1	28.00	2020
RADIATION OF IPAKODO 33kV FEEDER FROM SABO TS	P&C	19.52	1	19.52	2021
Proposed Alternative 33kV feeder for Magodo.	P&C	184.41	1	184.41	2020
Complete reconductoring of 3 No 11kV feeders (Community, Agboyi & Ketu)	P&C	79.14	1	79.14	2020
Completion of 68 Military Injection Station	P&C	100	1	100.00	2020
Proposed Police College 33kV line Ex Ogba TS	P&C	54.45	1	54.45	2022
Prop 33kV Double cct from Maryland TS	P&C	174.06	1	174.06	2021
Reconductoring/Reconstruction of Alausa 11kV line	P&C	5.35	1	5.35	2021
Proposed Anifowoshe 11kV feeder	P&C	12.42	1	12.42	2021
Relief of Opeilu 11kV Feeder with Oshoba Feeder	P&C	2.35	1	2.35	2020
Radiation of Majente 11kV feeder (ex Akute ISS) as relief	P&C	7.27	1	7.27	2020
Radiation of Matogun 11kV feeder to relieve Olambe 11kV	P&C	11.53	1	11.53	2020
Diverting Akute Injection to Olambe 33kV feeder	P&C	12.82	1	12.82	2020
Completion of Anthony Feeder	P&C	2.27	1	2.27	2020
Extension of Shonubi feeder	P&C	0.69	1	0.69	2020
Proposed Bucnor 11kV feeder; ex -Oke Afa ISS	P&C	25.29	1	25.29	2021
Proposed Pipeline 11kV feeder; ex- Ijegun ISS	P&C	25.38	1	25.38	2021
Proposed Obalagbe 11kV feeder; ex- Ijegun ISS	P&C	25.22	1	25.22	2021
Proposed Odoeran 1 X 15MVA ISS	P&C	550.17	1	550.17	2024
Proposed Orisunbare 1 X 15MVA ISS	P&C	563.64	1	563.64	2024
Proposed Fagbile 1 X 15MVA ISS	P&C	408.12	1	408.12	2024

Proposed Emzor 2MVA 33/11kV ex-Aswani 33kV feeder	P&C	34.25	1	34.25	2020
Relief of Overloaded DTs	P&C	6.25	487	3,043.75	2020
Reconductoring of LT overhead lines	P&C	2.51	3,135	7,868.85	2020
Reconductoring of LT overhead lines	P&C	2.51	9,405	23,606.55	2021
Reconductoring of LT overhead lines	P&C	2.51	6,270	15,737.70	2022
Reconductoring of LT overhead lines	P&C	2.51	6,270	15,737.70	2023
Reconductoring of LT overhead lines	P&C	2.51	6,270	15,737.70	2024
Maintenance of Overhead HV lines (11kV)	P&C	5.42	85	449.86	2020
Maintenance of Overhead HV lines (11kV)	P&C	5.42	205	1,111.10	2021
Maintenance of Overhead HV lines (33kV)	P&C	9.936	50	496.80	2021
DT remote monitoring Module	Reliability, Distribution Automation	0.15	2600	390.00	2020
Replacement of 11kV panels & switchgear with required: 3 incomer 9 outgoing at PTC	P&C	91	1	91.00	2021
Replacement of 11kV Alstom panels & switchgear with required: 1 incomer 4 outgoing at Sabo	P&C	32.5	1	32.50	2020
Replacement of 11kV panels & switchgear with 2 incomer 8 outgoing at Secretariat	P&C	71.5	1	71.50	2021
Replacement of 11kV panels & switchgear with required: 3 incomer 9 outgoing at Alimosho	P&C	91	1	91.00	2021
Replacement (conversion) of 1no 33kV indoor switchgear (to outdoor) at Agege	P&C	6.5	1	6.50	2021
Replacement of 11kV panels & switchgear with required: 2 incomer 9 outgoing at Igbobi	P&C	84.5	1	84.50	2021
Replacement of 11kV panels & switchgear with required: 3 incomer 9 outgoing at Oke Afa	P&C	91	1	91.00	2021
Replacement of 11kV panels & switchgear with 3 incomer 9 outgoing 2B/C at Iju	P&C	91	1	91.00	2021
Replacement of 11kV panels & switchgear with 2 incomer 4 outgoing at Opebi	P&C	45.5	1	45.50	2021
Replacement of 11kV panels & switchgear with required: 3 incomer 9 outgoing at Ilupeju	P&C	91	1	91.00	2021
Replacement (conversion) of 1no 33kV indoor switchgear (to outdoor) at Bolorunpelu	P&C	6.5	1	6.50	2021
Replacement (conversion) of 1no 33kV indoor switchgear (to outdoor) at Abesan	P&C	6.5	1	6.50	2021
Replacement of 11kV panels & switchgear with required: 2 incomer 6 outgoing at Ago Okota	P&C	58.5	1	58.50	2022

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Replacement of 11kV panels & switchgear with required: 2 incomer 6 outgoing at Wasimi	P&C	58.5	1	58.50	2022
Transformers on Plinth	P&C	6	150	900.00	
Replacement of 11kV panels & switchgear with required: 2 incomer 6 outgoing Replacement (conversion) of 1no 33kV indoor switchgear (to outdoor) at Owutu	P&C	65	1	65.00	2021
Replacement of 11kV panels & switchgear with required: 2 incomer 8 outgoing at Magodo	P&C	71.5	1	71.50	2021
Replacement of 11kV panels & switchgear with 1 incomer 3 outgoing at Yidi	P&C	32.5	1	32.50	2021
Replacement of 11kV panels & switchgear with required: 2 incomer 6 outgoing at Igando	P&C	58.5	1	58.50	2021
Replacement of 11kV panels & switchgear with required: 2 incomer 6 outgoing at Ijegun	P&C	58.5	1	58.50	2021
Replacement of 11kV panels & switchgear with required: 1 incomer 4 outgoing at Alasia	P&C	32.5	1	32.50	2021
Replacement of 11kV panels & switchgear with 1 incomer 4 outgoing at Abule Iroko	P&C	32.50	1	32.50	2021
Replacement of 11kV panels & switchgear with required: 1 incomer 4 outgoing at Isheri	P&C	32.5	1	32.50	2023
Replacement of 11kV panels & switchgear with 1 incomer 3 outgoing at Ayobo	P&C	26	1	26.00	2021
Replacement of 11kV panels & switchgear with 2 incomer 6 outgoing at Shasha	P&C	58.5	1	58.50	2021
Replacement of 11kV panels & switchgear with 2 incomer 6 outgoing at Yusuf	P&C	58.5	1	58.50	2023
Replacement of 11kV panels & switchgear with 1 incomer 4 outgoing at Ope Ilu	P&C	39	1	39.00	2023
DT remote monitoring Module	Reliability, Distribution Automation	0.15	2600	527.10	2021
DT remote monitoring Module	Reliability, Distribution Automation	0.15	2600	390.00	2022
DT remote monitoring Module	Reliability, Distribution Automation	0.15	2600	390.00	2023
DT remote monitoring Module	Reliability, Distribution Automation	0.15	1686	252.90	2024
Planned replacement of underground cables and assets	P&C	285.96	1	285.96	2020
Reconditioning of Power Transformers	Loss Reduction	10	50	500.00	2021
Procurement of Network Improvement Tools and Machinery	PC&M	417.06	1	417.06	2020
Procurement of Fault Passage Indicators	Reliability, Distribution Automation	5.34	100	534.00	2020

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Planned replacement of underground cables and assets	P&C	285.96	1	285.96	2021
Procurement of Network Improvement Tools and Machinery	PC&M	417.06	1	417.06	2021
Procurement of Network Improvement Tools and Machinery	PC&M	417.06	1	417.06	2022
Planned replacement of underground cables and assets	P&C	285.96	1	285.96	2022
Planned replacement of underground cables and assets	P&C	285.96	1	285.96	2023
Planned replacement of underground cables and assets	P&C	285.96	1	285.96	2024
installation of Remote Terminal Units at Injection substations	Reliability, Distribution Automation	5	15	75.00	2020
installation of Remote Terminal Units at Injection substations	Reliability, Distribution Automation	5	13	65.00	2021
installation of Remote Terminal Units at Injection substations	Reliability, Distribution Automation	5	13	65.00	2022
installation of Remote Terminal Units at Injection substations	Reliability, Distribution Automation	5	13	65.00	2023
installation of Remote Terminal Units at Injection substations	Reliability, Distribution Automation	5	13	65.00	2021
Licenses for AUTOCAD	IT& Automation	50	1	50.00	2021
Licenses for system Modelling tool (NEPLAN)	IT& Automation	5	15	75.00	2020
Fencing of Substations	P&C	0.5	605	302.50	2020
Fencing of Substations	P&C	0.5	605	302.50	2021

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Annex H Load allocation

In all scenarios, we assume that the MYTO model is amended to reflect current load allocation for future tariffs.

The June 2019 Minor Review tariffs for 2020 are shown in Table 48. Our current load allocation analysis is based on our billing data and enumeration data. Based on the assumed load allocation in the June 2019 Minor Review, the 2020 tariffs would result in an average overall tariff of 37.9 N/kWh. If the actual load allocation is used, the 2020 tariffs would result in an average overall tariff of 38.3 N/kWh.

Table 48: Impact of actual load allocation on the average tariff across customer classes

Tariff class	June 2019 Minor Review		Actual load allocation
	Tariff for 2020	Assumed load allocation	
R1	4.00	0%	0%
R2SP	30.36	50%	23%
R2TP	33.89	4%	30%
R3	50.68	0%	1%
R4	51.29	0%	0%
C1SP	34.88	14%	8%
C1TP	39.19	1%	13%
C2	52.03	5%	6%
C3	52.58	1%	2%
D1	39.37	0%	1%
D2	52.91	2%	2%
D3	53.56	19%	11%
A1	37.25	1%	1%
A2	41.95	1%	1%
A3	42.16	1%	1%
S1	26.97	0%	0%
Average tariff across all tariff classes based on June 2019 Minor Review tariffs for 2020		37.9	38.3

Annex I Regulatory asset inventory

Ikeja Electric's Regulatory Asset inventory will be submitted as a separate document.

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Annex J Network constraint analysis

The network constraint analysis is discussed in Section 5.3.1.

J. 1 11kV Voltage Level Analysis

Table 49: 11kV Feeders Loading Analysis

Feeder Name	Line Rating (Amps)	2019 Constrained Loading (Amps)	2019 Line Loading (%)	2024 Constrained Loading (Amps)	2024 Line Loading (%)
FADEYI	337.91	200.68	59%	371.96	110%
JIBOWU	337.91	282.27	84%	370.41	110%
MUSHIN 2	337.91	343.12	102%	496.75	147%
AKOKA	337.91	337.42	100%	363.32	108%
COMMUNITY	334.34	299.16	89%	315.02	94%
ILAJE	337.91	286.76	85%	573.52	170%
OLUSOSUN	278.08	357.91	129%	535.92	193%
SALVATION	286.98	249.06	87%	394.03	137%
AGBAOKU	261.43	202.39	77%	262.62	100%
ALLEN	286.46	366.18	128%	669.40	234%
OREGUN	294.19	194.26	66%	74.45	25%
SIYANBOLA	313.79	197.92	63%	331.43	106%
ALAUSA	304.97	289.90	95%	686.23	225%
KUDIRAT	285.06	181.69	64%	778.83	273%
MORRISON	332.97	119.18	36%	341.33	103%
OGUNDANA	265.96	182.66	69%	332.49	125%
AROMIRE	313.53	58.34	19%	244.08	78%
AWOLOWO	328.01	232.89	71%	494.10	151%
ISHERI	267.85	151.53	57%	350.79	131%
OLOWORA	243.94	198.90	82%	372.04	153%
BANKOLE	255.90	175.98	69%	377.71	148%
ORISHA	273.04	208.94	77%	280.86	103%
UNILAG	237.15	282.55	119%	287.41	121%
SHANGISHA	266.04	220.29	83%	265.50	100%
OWULADE	285.13	250.57	88%	231.18	81%
OLUYOMBO	294.54	-	0%	-	0%
EMMANUEL KESHI	258.17	223.75	87%	262.97	102%
CMD	248.59	226.19	91%	390.23	157%
BASHIRU SHITTU	305.73	159.19	52%	247.01	81%
OJODU	324.81	188.90	58%	424.93	131%
ALAGBOLE	291.91	159.82	55%	303.86	104%
KINGS AVENUE	280.96	302.38	108%	382.43	136%
OJODU-EXPRESS	327.11	317.60	97%	525.24	161%
RIVER VALLEY	251.61	158.60	63%	242.47	96%

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Feeder Name	Line Rating (Amps)	2019 Constrained Loading (Amps)	2019 Line Loading (%)	2024 Constrained Loading (Amps)	2024 Line Loading (%)
YAKOYO	309.55	263.02	85%	323.47	104%
ESTATE	322.20	384.46	119%	349.76	109%
LATEEF JAKANDE	310.90	254.63	82%	435.98	140%
OMOLE	294.84	283.28	96%	383.34	130%
AGIDINGBI	311.09	121.16	39%	226.01	73%
7UP	294.86	188.85	64%	311.64	106%
UAC	296.51	337.02	114%	558.57	188%
AKOWONJO	332.24	375.78	113%	568.92	171%
FHA	275.05	327.99	119%	298.51	109%
OKI	301.58	308.36	102%	574.94	191%
SHASHA	301.08	374.29	124%	585.56	194%
ORELOPE	321.99	334.50	104%	481.11	149%
POWER LINE	299.84	375.91	125%	271.84	91%
ABULE-EGBA	267.54	382.54	143%	455.78	170%
ORILE-AGEGE	311.42	348.49	112%	534.32	172%
PEN-CINEMA	293.47	402.85	137%	651.42	222%
TABON-TABON	314.92	346.97	110%	566.34	180%
OYEMEKUN	266.99	311.19	117%	445.50	167%
ALIMOSHO	303.32	372.87	123%	708.27	234%
OKUNOLA	305.00	330.72	108%	499.61	164%
OKO-OBA	337.91	359.83	106%	531.31	157%
IJU ROAD	317.78	400.18	126%	704.25	222%
AJASA	278.81	287.34	103%	487.21	175%
OKE-ODO	268.76	334.36	124%	644.21	240%
EKORO	256.03	210.50	82%	-	0%
EKORO-AGBELE	304.47	340.79	112%	579.99	190%
OLOTA	303.20	246.23	81%	475.98	157%
UNITY	320.59	409.65	128%	624.09	195%
KUWAIT	311.92	258.87	83%	343.55	110%
OLORUNADABA	292.22	338.71	116%	724.35	248%
NYSC	288.89	269.64	93%	504.61	175%
ARIGBANLA	273.78	383.77	140%	572.60	209%
OYEWOLE	317.33	328.20	103%	833.51	263%
OLD OJO ROAD	262.48	309.45	118%	281.99	107%
IJESHA EXPRESS	322.04	-	0%	-	0%
JAKANDE 1	204.34	376.82	184%	469.63	230%
JAKANDE 2	323.52	455.62	141%	457.55	141%
BADA	273.46	396.61	145%	936.11	342%
ITELE	278.19	368.58	132%	593.67	213%
AYOBO	334.67	352.34	105%	552.42	165%
IKOLA	274.39	401.67	146%	612.11	223%
FADAYOMI	311.34	313.83	101%	532.88	171%
BARUWA	258.13	405.40	157%	682.35	264%

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Feeder Name	Line Rating (Amps)	2019 Constrained Loading (Amps)	2019 Line Loading (%)	2024 Constrained Loading (Amps)	2024 Line Loading (%)
IPAJA	309.78	380.70	123%	736.17	238%
ABORU	316.81	374.68	118%	676.70	214%
ABESAN	232.39	362.98	156%	490.56	211%
SHAGARI	320.04	386.47	121%	586.35	183%
WALTER ANDERM	335.89	396.71	118%	928.62	276%
BODE WILLIAMS	314.59	415.02	132%	721.06	229%
ISOTO	241.68	570.88	236%	592.06	245%
AYETOBI	264.15	302.17	114%	527.73	200%
EJIGBO	331.91	390.53	118%	554.17	167%
IRE-AKARI	267.34	418.99	157%	619.48	232%
LCHE	260.74	372.17	143%	453.97	174%
ILAMOSHE	313.01	397.12	127%	465.58	149%
OSOLO	306.49	336.61	110%	274.31	89%
ORI-OKE	329.41	368.62	112%	497.34	151%
NNPC	295.61	381.64	129%	557.20	188%
BUNGALOW	244.32	404.38	166%	556.18	228%
ABANISHE	310.63	325.33	105%	421.47	136%
KUDAKI	313.74	352.66	112%	479.75	153%
EGAN	249.16	364.53	146%	536.35	215%
NEW IGANDO	274.18	433.51	158%	628.05	229%
AKESAN	294.36	374.36	127%	582.81	198%
AGRIC ROAD	290.11	360.38	124%	481.15	166%
IGANDO-GENERAL HOSPITAL	240.15	423.47	176%	587.57	245%
OKERUBE	284.76	366.29	129%	567.58	199%
IKOTUN	280.46	374.85	134%	615.81	220%
IJEGUN	290.21	483.66	167%	715.04	246%
ISHERI OSHUN	242.05	422.71	175%	677.34	280%
ORISUNBARE	330.86	273.77	83%	507.13	153%
OGUNTADE	337.56	328.96	97%	425.37	126%
FOURSQUARE	288.73	366.53	127%	440.99	153%
NAF	337.91	224.41	66%	4.46	1%
ABARANJE	248.09	398.48	161%	739.23	298%
IDIMU	320.48	371.41	116%	585.48	183%
ISIJOLA	285.56	405.80	142%	644.59	226%
GOVERNOR	266.52	322.05	121%	826.24	310%
LIASU	317.42	388.68	122%	549.64	173%
AYANGBUREN	262.73	219.66	84%	457.37	174%
LAGOS ROAD	317.85	322.67	102%	488.21	154%
MARY HILL	333.70	307.81	92%	391.98	117%
IJEBU-ODE	266.72	393.82	148%	608.68	228%
GBERIGBE	337.69	111.80	33%	288.79	86%
LUWASA	328.88	208.55	63%	239.89	73%
EYITA	225.39	278.78	124%	620.71	275%

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Feeder Name	Line Rating (Amps)	2019 Constrained Loading (Amps)	2019 Line Loading (%)	2024 Constrained Loading (Amps)	2024 Line Loading (%)
LASUNWON	315.06	233.12	74%	234.54	74%
LADEGA	265.31	384.60	145%	578.27	218%
IGBOGBO	256.72	342.34	133%	463.96	181%
ERUNWEN	314.66	267.04	85%	497.06	158%
ABUJA	302.53	341.05	113%	503.44	166%
IPAKODO	310.84	294.94	95%	306.43	99%
WAEC	293.24	273.68	93%	497.11	170%
AGRIC	295.61	399.54	135%	520.87	176%
ORI-OKUTA	249.08	279.30	112%	472.27	190%
MAJIDUN	337.77	146.63	43%	326.95	97%
ISAWO	299.10	379.43	127%	533.31	178%
ASOLO	279.33	373.50	134%	564.25	202%
TOWNSHIP	232.06	242.90	105%	496.91	214%
LASU	222.91	163.30	73%	337.81	152%
WATER WORKS	250.12	123.50	49%	311.34	124%
BAYEKU	304.23	422.59	139%	623.60	205%
OFIN	314.17	416.96	133%	584.31	186%
ODOFIN	303.15	371.94	123%	460.52	152%
IGBOGBO-AGBELE	262.48	327.53	125%	360.08	137%
BHOJSON	320.38	157.11	49%	224.33	70%
RIDA PLASTIC	523.67	111.94	21%	31.01	6%
ATM	245.18	36.86	15%	30.78	13%
MARKET	304.17	283.56	93%	364.56	120%
ORTHOPAEDIC	337.91	397.73	118%	501.82	149%
MUSHIN 1	337.91	287.03	85%	482.83	143%
RAILWAY	325.73	257.07	79%	660.66	203%
IKORODU ROAD	264.39	291.36	110%	496.32	188%
PALMGROVE	337.91	360.84	107%	409.32	121%
COKER	269.00	347.19	129%	410.07	152%
PZ	-	-	0%	-	0%
L&K	291.32	374.67	129%	566.42	194%
BYPASS	332.69	342.62	103%	708.65	213%
OBANIKORO	337.91	279.01	83%	353.78	105%
ILUPEJU INDUSTRIAL	337.91	383.76	114%	501.10	148%
IKORODU	303.92	196.73	65%	330.69	109%
ARMY CANTONMENT	309.19	347.93	113%	27.54	9%
COUNCIL	323.55	393.99	122%	468.27	145%
ALASIA	332.72	280.01	84%	406.98	122%
OWOSENI	279.44	308.28	110%	432.70	155%
AIRPORT ROAD	318.90	341.11	107%	430.82	135%
DOMINO	263.81	307.13	116%	514.73	195%
NEW ESTATE	321.09	153.82	48%	320.54	100%
SHOLANKE	291.64	374.94	129%	510.15	175%

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Feeder Name	Line Rating (Amps)	2019 Constrained Loading (Amps)	2019 Line Loading (%)	2024 Constrained Loading (Amps)	2024 Line Loading (%)
MAKINDE	254.76	295.61	116%	444.64	175%
SAUBANA	244.65	292.36	120%	485.03	198%
POST OFFICE	276.99	325.65	118%	576.36	208%
ASWANI	333.94	215.54	65%	212.33	64%
ABIMBOLA	332.35	288.47	87%	632.85	190%
ADEMULEGUN	323.62	274.99	85%	520.19	161%
OKOTA	334.43	433.57	130%	668.40	200%
AMUWO-IJESHA	315.36	18.21	6%	29.72	9%
CANAL	330.15	280.18	85%	642.98	195%
IBALEX	300.93	343.08	114%	492.91	164%
AGO	314.76	283.36	90%	707.66	225%
APENA	332.94	255.51	77%	283.46	85%
FASHEUN	326.03	387.56	119%	510.57	157%
AMUWO INDUSTRIAL	332.80	388.76	117%	782.15	235%
OKE-OGBERE	293.58	378.18	129%	459.86	157%
LAKE VIEW	326.34	194.63	60%	314.61	96%
PTC	300.29	274.93	92%	252.25	84%
OKUPE	270.35	365.63	135%	451.58	167%
KETU	296.17	366.76	124%	606.02	205%
ARAROMI	303.95	360.17	118%	382.78	126%
AGILITI	248.43	338.35	136%	532.73	214%
AKANIMODO	326.86	269.47	82%	451.49	138%
WASIMI	304.31	349.21	115%	564.55	186%
AGIDI	262.56	328.04	125%	351.37	134%
DEMURIN	315.16	338.47	107%	717.63	228%
SYLVIA	259.74	258.60	100%	289.58	111%
IKOSI	278.46	328.04	118%	390.41	140%
THOMAS LANIYAN	310.65	307.78	99%	286.97	92%
AGBOYI	291.48	311.10	107%	471.87	162%
ARABA	294.30	361.21	123%	443.49	151%
OPEBI	281.40	339.66	121%	357.84	127%
MEDICAL	264.49	279.02	105%	506.17	191%
AWUSE	334.10	233.29	70%	263.24	79%
OLOWU	280.87	300.09	107%	367.36	131%
OBA AKINJOBI	299.21	231.96	78%	257.74	86%
PTC-GENERAL HOSPITAL	276.76	203.52	74%	221.43	80%
ISAAC JOHN	302.82	200.51	66%	215.12	71%
ODUDUWA	327.55	276.63	84%	267.82	82%
OJOTA	302.14	340.42	113%	429.50	142%
GRA	305.13	68.09	22%	220.37	72%
WESTEX	293.79	258.72	88%	508.93	173%
AGODO	281.74	335.97	119%	766.26	272%
INDUSTRIAL	283.97	381.72	134%	462.23	163%

Feeder Name	Line Rating (Amps)	2019 Constrained Loading (Amps)	2019 Line Loading (%)	2024 Constrained Loading (Amps)	2024 Line Loading (%)
CENTEX	231.89	229.73	99%	689.86	297%
ITA OLUWO	322.16	342.97	106%	464.20	144%
CANTONMENT	260.02	345.42	133%	571.89	220%
AJAO ROAD	319.73	131.59	41%	332.21	104%
ADENIYI JONES	314.18	285.33	91%	398.47	127%
ABEOKUTA EXPRESS	315.12	425.45	135%	572.83	182%
JANKARA	337.91	392.15	116%	801.79	237%
MEIRAN	337.91	403.26	119%		0%
AGBADO II	337.91	394.16	117%	415.84	123%
BECKLEY	337.91	266.33	79%	362.96	107%
AGBE ROAD	337.91	400.95	119%	501.73	148%
CAPITOL	242.88	339.77	140%	487.73	201%
SULE	266.18	363.31	136%	612.67	230%
NEW DOPEMU	301.88	363.44	120%	575.38	191%
OGBA-IFAKO	331.54	337.24	102%	616.23	186%
MANGORO	276.68	269.79	98%	405.52	147%
AGEGE	292.00	336.19	115%	556.18	190%
M&B	336.83	256.30	76%	485.59	144%
OBA AKRAN	305.64	364.49	119%	480.29	157%
IJAYE	291.16	364.44	125%	707.92	243%
ISOKOKO	284.20	332.03	117%	67.09	24%
NOB-OLUWA	255.21	371.09	145%	439.04	172%
OKE-IRA	247.49	325.40	131%	611.10	247%
THOMAS SALAKO	327.81	363.87	111%	569.23	174%
KAYODE	286.05	350.43	123%	383.36	134%
ABIODUN JAGUN	308.15	329.00	107%	427.48	139%
OLAMBE	337.91	377.64	112%	918.42	272%
JOLASCO	337.91	346.16	102%	517.88	153%
GRAILAND	337.91	216.51	64%	413.15	122%
AJUWON	337.91	292.66	87%	752.31	223%
GALILEE	337.91	389.87	115%	639.28	189%
ASORE	337.91	305.98	91%	492.02	146%
AKUTE	337.91	-	0%	-	0%
ISHAGA	337.91	411.78	122%	797.91	236%
AGBADO 1	258.17	371.79	144%	726.37	281%
IJOKO	325.95	354.35	109%	804.28	247%
ADIYAN	258.17	328.31	127%	500.01	194%
OSOBA	337.91	424.31	126%	818.23	242%
OPEILU	296.42	405.86	137%	996.32	336%
ISHASHI	337.91	414.85	123%	652.58	193%
OYEYEMI	258.17	343.31	133%	403.13	156%
YUSUF	337.91	303.72	90%	454.06	134%
AKERA	337.91	352.31	104%	562.18	166%

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Feeder Name	Line Rating (Amps)	2019 Constrained Loading (Amps)	2019 Line Loading (%)	2024 Constrained Loading (Amps)	2024 Line Loading (%)
AGBEIFA	308.44	307.21	100%	659.89	214%
ILAPO	293.28	392.30	134%	601.50	205%
ALAKUKO	329.57	427.38	130%	694.36	211%
ABULE-IROKO	337.91	366.29	108%	591.65	175%
BOOKS	337.91	287.32	85%	335.37	99%
ANTHONY	337.91	372.42	110%	369.92	109%
OWORO-IFAKO	290.88	227.08	78%	349.06	120%
HOSPITAL	337.91	319.06	94%	617.89	183%
LADILAC	310.55	335.22	108%	503.65	162%
OWORO	322.62	203.69	63%	380.41	118%
PEDRO	312.49	369.09	118%	443.37	142%
BARIGA	300.57	353.32	118%	530.64	177%
GBAGADA	324.74	322.30	99%	349.93	108%
CAC	262.64	335.96	128%	353.93	135%
OGUDU ROAD	314.98	340.65	108%	492.17	156%
OGUDU-EXPRESS	252.80	351.21	139%	213.46	84%
ALAPERE	328.75	209.97	64%	94.00	29%
ORIOLA	308.59	281.89	91%	455.28	148%
BALOGUN	334.74	328.03	98%	423.57	127%
SOLUYI	305.59	315.09	103%	300.50	98%
MILITARY	327.55	319.32	97%	547.26	167%
APATA	310.19	294.78	95%	310.58	100%
ADUROSAKIN	300.32	264.99	88%	274.43	91%

Table 50: 11kV Transformation Capacity Analysis

Feeder Name	Transformation Capacity (MVA)	2019 Max Load (MVA)	2019 Loading (%)	2024 Max Load (MVA)	2024 Loading (%)
FADEYI	4.3	3.2	76%	6.0	142%
JIBOWU	13.2	4.6	35%	6.1	46%
MUSHIN 2	11.5	6.2	54%	9.0	79%
AKOKA	17.5	5.5	31%	5.9	34%
COMMUNITY	20.0	5.1	26%	5.4	27%
ILAJE	15.6	4.9	32%	9.8	63%
OLUSOSUN	21.9	5.9	27%	8.8	40%
SALVATION	20.2	4.6	23%	7.3	36%
AGBAOKU	12.5	3.8	30%	4.9	39%
ALLEN	18.3	6.0	33%	11.0	60%
OREGUN	11.6	3.7	32%	1.4	12%

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Feeder Name	Transformation Capacity (MVA)	2019 Max Load (MVA)	2019 Loading (%)	2024 Max Load (MVA)	2024 Loading (%)
SIYANBOLA	10.9	3.7	34%	6.3	57%
ALAUSA	15.7	4.8	30%	11.2	72%
KUDIRAT	14.0	3.4	25%	14.7	105%
MORRISON	7.4	2.2	30%	6.4	87%
OGUNDANA	10.7	3.4	32%	6.3	59%
AROMIRE	2.8	1.0	36%	4.2	149%
AWOLOWO	14.2	4.4	31%	9.2	65%
ISHERI	6.1	2.5	40%	5.7	93%
OLOWORA	8.2	3.8	46%	7.0	86%
BANKOLE	6.8	3.3	49%	7.1	106%
ORISHA	5.2	3.4	65%	4.5	87%
UNILAG	7.7	4.7	61%	4.8	62%
SHANGISHA	6.4	3.7	58%	4.5	70%
OWULADE	5.7	4.5	79%	4.2	73%
OLUYOMBO	-	-	-	-	-
EMMANUEL KESHI	6.6	3.8	58%	4.5	68%
CMD	6.0	3.7	62%	6.5	108%
BASHIRU SHITTU	7.1	2.9	40%	4.4	63%
OJODU	6.9	3.1	45%	7.0	102%
ALAGBOLE	6.8	3.0	45%	5.8	85%
KINGS AVENUE	10.7	5.8	54%	7.3	68%
OJODU-EXPRESS	14.7	5.2	35%	8.6	59%
RIVER VALLEY	4.9	3.0	62%	4.6	95%
YAKOYO	8.7	5.0	58%	6.2	71%
ESTATE	18.8	6.4	34%	5.9	31%
LATEEF JAKANDE	16.9	4.7	28%	8.1	48%
OMOLE	14.8	5.2	36%	7.1	48%
AGIDINGBI	5.0	2.0	40%	3.7	75%
7UP	15.4	3.5	23%	5.8	38%
UAC	18.4	6.2	34%	10.4	56%
AKOWONJO	12.3	6.1	49%	9.2	75%
FHA	14.9	6.2	42%	5.7	38%
OKI	10.6	5.9	55%	11.0	103%
SHASHA	13.6	6.4	47%	10.0	74%
ORELOPE	12.0	6.4	53%	9.2	76%
POWER LINE	9.1	6.4	70%	4.6	51%
ABULE-EGBA	29.5	6.9	23%	8.2	28%

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Feeder Name	Transformation Capacity (MVA)	2019 Max Load (MVA)	2019 Loading (%)	2024 Max Load (MVA)	2024 Loading (%)
ORILE-AGEGE	14.8	6.3	42%	9.6	65%
PEN-CINEMA	13.7	6.8	49%	10.9	80%
TABON-TABON	14.5	6.2	43%	10.2	71%
OYEMEKUN	12.5	5.6	45%	8.0	64%
ALIMOSHO	18.0	6.3	35%	11.9	66%
OKUNOLA	16.0	6.3	40%	9.5	60%
OKO-OBA	19.3	6.7	35%	9.9	52%
IJU ROAD	20.9	6.9	33%	12.1	58%
AJASA	8.3	5.4	65%	9.1	110%
OKE-ODO	11.4	6.3	55%	12.1	106%
EKORO	0.5	3.5	706%	3.5	706%
EKORO-AGBELE	10.7	5.8	54%	9.8	92%
OLOTA	6.3	4.6	73%	8.9	141%
UNITY	16.9	6.6	39%	10.1	60%
KUWAIT	9.0	4.7	52%	6.2	69%
OLORUNADABA	9.9	6.1	62%	13.0	132%
NYSC	10.2	4.6	45%	8.7	85%
ARIGBANLA	10.2	6.3	62%	9.4	92%
OYEWOLE	15.5	6.1	40%	15.6	101%
OLD OJO ROAD	10.0	5.1	51%	4.7	47%
IJESHA EXPRESS	-	-	-	0.0	-
JAKANDE 1	15.7	6.5	41%	8.1	51%
JAKANDE 2	20.6	7.4	36%	7.4	36%
BADA	19.3	6.6	34%	15.5	80%
ITELE	11.1	6.2	56%	10.1	91%
AYOBO	7.7	6.6	85%	10.3	134%
IKOLA	15.4	6.6	43%	10.0	65%
FADAYOMI	11.8	6.0	51%	10.2	86%
BARUWA	15.3	6.6	43%	11.1	72%
IPAJA	11.0	6.4	58%	12.3	112%
ABORU	12.9	6.8	53%	12.3	96%
ABESAN	15.1	6.6	44%	8.9	59%
SHAGARI	11.7	6.5	55%	9.8	84%
WALTER ANDERM	14.1	6.6	47%	15.4	109%
BODE WILLIAMS	19.7	7.0	35%	12.1	61%
ISOTO	10.5	9.6	91%	9.9	95%
AYETOBI	10.5	4.9	47%	8.5	82%

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Feeder Name	Transformation Capacity (MVA)	2019 Max Load (MVA)	2019 Loading (%)	2024 Max Load (MVA)	2024 Loading (%)
EJIGBO	13.2	6.6	50%	9.4	71%
IRE-AKARI	12.4	6.8	55%	10.0	81%
LCHE	11.9	7.0	59%	8.6	72%
ILAMOSHE	10.4	6.8	65%	8.0	77%
OSOLO	20.9	5.5	26%	4.5	22%
ORI-OKE	10.8	7.0	64%	9.4	87%
NNPC	12.7	6.5	51%	9.4	75%
BUNGALOW	16.5	6.9	42%	9.5	58%
ABANISHE	9.5	5.3	55%	6.8	72%
KUDAKI	6.7	5.7	86%	7.8	116%
EGAN	9.7	6.8	70%	9.9	102%
NEW IGANDO	18.5	7.4	40%	10.6	58%
AKESAN	21.4	6.8	32%	10.6	50%
AGRIC ROAD	14.8	6.6	44%	8.8	59%
IGANDO-GENERAL HOSPITAL	19.1	7.1	37%	9.9	52%
OKERUBE	13.5	6.7	50%	10.3	77%
IKOTUN	11.5	6.4	56%	10.6	92%
IJEGUN	19.0	8.4	44%	12.4	65%
ISHERI OSHUN	14.4	7.3	51%	11.7	82%
ORISUNBARE	9.7	4.7	49%	8.8	91%
OGUNTADE	16.5	5.6	34%	7.3	44%
FOURSQUARE	8.5	6.2	73%	7.5	88%
NAF	0.7	4.3	611%	0.1	12%
ABARANJE	12.4	6.6	53%	12.3	99%
IDIMU	12.1	6.1	51%	9.6	80%
ISIJOLA	13.3	6.9	52%	10.9	82%
GOVERNOR	10.3	5.7	55%	14.6	142%
LIASU	0.2	6.9	3433%	9.7	4855%
AYANGBUREN	7.6	4.0	53%	8.3	109%
LAGOS ROAD	11.8	5.9	50%	8.9	76%
MARY HILL	11.0	5.6	51%	7.1	65%
IJEBU-ODE	17.6	6.7	38%	10.3	59%
GBERIGBE	10.2	1.9	18%	4.8	47%
LUWASA	6.2	3.4	54%	3.9	63%
EYITA	7.3	4.6	63%	10.2	140%
LASUNWON	8.8	4.0	45%	4.0	46%
LADEGA	11.8	6.4	55%	9.7	82%

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Feeder Name	Transformation Capacity (MVA)	2019 Max Load (MVA)	2019 Loading (%)	2024 Max Load (MVA)	2024 Loading (%)
IGBOGBO	12.0	6.2	52%	8.4	70%
ERUNWEN	14.2	4.9	34%	9.0	64%
ABUJA	18.2	5.7	31%	8.3	46%
IPAKODO	8.5	5.6	66%	5.8	69%
WAEC	12.5	5.2	42%	9.5	76%
AGRIC	9.3	6.9	74%	8.9	97%
ORI-OKUTA	12.9	5.2	41%	8.8	68%
MAJIDUN	8.4	2.4	28%	5.3	63%
ISAWO	16.9	7.1	42%	10.0	59%
ASOLO	16.9	7.0	41%	10.6	62%
TOWNSHIP	12.5	4.0	32%	8.2	66%
LASU	9.4	2.7	29%	5.7	60%
WATER WORKS	8.2	2.0	24%	5.0	61%
BAYEKU	20.8	7.0	34%	10.3	49%
OFIN	18.4	6.8	37%	9.5	52%
ODOFIN	13.1	6.2	47%	7.6	58%
IGBOGBO-AGBELE	12.5	6.0	48%	6.6	53%
BHOJSON	5.9	2.5	43%	3.6	62%
RIDA PLASTIC	3.0	1.9	63%	0.5	17%
ATM	3.0	0.6	21%	0.5	17%
MARKET	13.3	5.4	40%	6.9	52%
ORTHOPAEDIC	12.1	6.6	55%	8.3	69%
MUSHIN 1	7.1	4.9	69%	8.3	117%
RAILWAY	11.9	4.7	40%	12.1	102%
IKORODU ROAD	11.7	5.3	46%	9.1	78%
PALMGROVE	16.6	6.6	40%	7.5	45%
COKER	11.4	5.8	51%	6.9	60%
PZ	-	-	-	-	-
L&K	19.0	6.2	33%	9.4	50%
BYPASS	27.2	5.9	22%	12.2	45%
OBANIKORO	10.1	4.7	47%	6.0	59%
ILUPEJU INDUSTRIAL	16.1	6.6	41%	8.6	54%
IKORODU	6.7	3.4	51%	5.7	85%
ARMY CANTONMENT	9.2	6.6	72%	0.5	6%
COUNCIL	10.7	6.6	62%	7.9	74%
ALASIA	11.4	5.2	46%	7.5	66%
OWOSENI	6.5	5.7	89%	8.0	124%

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Feeder Name	Transformation Capacity (MVA)	2019 Max Load (MVA)	2019 Loading (%)	2024 Max Load (MVA)	2024 Loading (%)
AIRPORT ROAD	19.7	6.6	34%	8.4	42%
DOMINO	18.0	6.0	33%	10.0	56%
NEW ESTATE	3.5	2.5	72%	5.2	150%
SHOLANKE	18.9	6.4	34%	8.7	46%
MAKINDE	6.8	5.6	82%	8.4	123%
SAUBANA	5.7	4.7	84%	7.9	139%
POST OFFICE	0.1	5.3	10672%	9.4	18888%
ASWANI	10.5	3.6	34%	3.6	34%
ABIMBOLA	16.7	4.8	29%	10.6	64%
ADEMULEGUN	13.7	5.0	37%	9.6	70%
OKOTA	13.2	8.0	61%	12.3	93%
AMUWO-IJESHA	1.2	0.3	26%	0.5	42%
CANAL	10.8	5.1	48%	11.8	110%
IBALEX	19.5	6.3	32%	9.0	47%
AGO	16.1	5.3	33%	13.1	82%
APENA	0.4	4.7	1353%	5.3	1501%
FASHEUN	15.7	7.1	45%	9.4	60%
AMUWO INDUSTRIAL	34.7	6.7	19%	13.4	39%
OKE-OGBERE	11.6	6.1	53%	7.4	64%
LAKE VIEW	8.4	3.6	43%	5.8	70%
PTC	16.3	5.0	31%	4.6	28%
OKUPE	12.2	5.9	49%	7.3	60%
KETU	14.0	6.0	43%	9.9	71%
ARAROMI	8.4	6.6	79%	7.0	84%
AGILITI	8.2	6.2	76%	9.8	119%
AKANIMODO	8.1	4.9	61%	8.3	102%
WASIMI	17.6	5.7	32%	9.1	52%
AGIDI	11.6	5.4	47%	5.8	50%
DEMURIN	15.0	6.2	41%	13.2	88%
SYLVIA	13.7	4.7	35%	5.3	39%
IKOSI	22.0	5.6	26%	6.7	30%
THOMAS LANIYAN	17.9	5.2	29%	4.9	27%
AGBOYI	15.6	5.2	33%	7.8	50%
ARABA	15.1	5.8	39%	7.2	48%
OPEBI	14.3	6.2	44%	6.6	46%
MEDICAL	4.6	4.6	102%	8.4	184%
AWUSE	12.7	4.0	31%	4.5	35%

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Feeder Name	Transformation Capacity (MVA)	2019 Max Load (MVA)	2019 Loading (%)	2024 Max Load (MVA)	2024 Loading (%)
OLOWU	7.1	5.6	80%	6.9	97%
OBA AKINJOBI	9.5	4.3	46%	4.8	51%
PTC-GENERAL HOSPITAL	7.0	3.5	50%	3.8	55%
ISAAC JOHN	12.1	3.8	31%	4.0	33%
ODUDUWA	4.8	4.5	95%	4.4	92%
OJOTA	11.4	6.2	55%	7.9	69%
GRA	8.4	1.3	15%	4.0	48%
WESTEX	16.8	4.8	28%	9.3	56%
AGODO	13.5	6.4	48%	14.6	109%
INDUSTRIAL	11.6	6.3	54%	7.6	66%
CENTEX	22.3	4.4	20%	13.1	59%
ITA OLUWO	20.6	6.5	32%	8.8	43%
CANTONMENT	8.8	5.6	64%	9.3	105%
AJAO ROAD	6.1	2.3	37%	5.7	93%
ADENIYI JONES	23.4	5.2	22%	7.3	31%
ABEOKUTA EXPRESS	19.4	7.1	36%	9.5	49%
JANKARA	15.2	6.4	42%	13.1	87%
MEIRAN	-	6.8	-	6.8	-
AGBADO II	16.7	6.8	40%	7.1	43%
BECKLEY	8.9	4.5	51%	6.2	69%
AGBE ROAD	12.2	6.5	53%	8.1	67%
CAPITOL	14.2	5.8	41%	8.4	59%
SULE	14.2	6.2	43%	10.4	73%
NEW DOPEMU	13.0	5.9	45%	9.3	72%
OGBA-IFAKO	27.7	6.2	23%	11.4	41%
MANGORO	15.9	5.0	31%	7.5	47%
AGEGE	14.0	6.2	45%	10.3	74%
M&B	15.6	4.7	31%	9.0	58%
OBA AKRAN	26.4	6.2	24%	8.2	31%
IJAYE	16.5	6.2	38%	12.1	73%
ISOKOKO	2.2	6.2	280%	1.2	57%
NOB-OLUWA	13.6	6.2	46%	7.4	54%
OKE-IRA	15.1	5.6	37%	10.5	69%
THOMAS SALAKO	14.3	6.2	44%	9.8	68%
KAYODE	22.3	6.0	27%	6.6	30%
ABIODUN JAGUN	10.3	5.6	55%	7.3	71%
OLAMBE	13.3	6.5	49%	15.7	119%

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Feeder Name	Transformation Capacity (MVA)	2019 Max Load (MVA)	2019 Loading (%)	2024 Max Load (MVA)	2024 Loading (%)
JOLASCO	15.0	6.2	42%	9.3	62%
GRAILAND	9.1	4.1	46%	7.9	87%
AJUWON	10.0	5.0	50%	12.9	129%
GALILEE	11.7	6.7	57%	11.0	94%
ASORE	9.4	5.8	62%	9.4	100%
AKUTE	-	-	-	-	-
ISHAGA	4.0	6.7	169%	13.1	327%
AGBADO 1	13.6	7.1	52%	13.8	102%
IJOKO	25.3	6.7	26%	15.2	60%
ADIYAN	10.2	6.2	61%	9.4	93%
OSOBA	13.5	7.0	52%	13.4	100%
OPEILU	20.0	7.3	37%	17.9	90%
ISHASHI	5.4	6.7	126%	10.6	198%
OYEYEMI	9.6	6.5	68%	7.7	80%
YUSUF	6.9	5.0	72%	7.4	108%
AKERA	8.9	6.0	67%	9.5	107%
AGBEIFA	9.2	5.3	57%	11.3	123%
ILAPO	4.0	6.7	168%	10.2	258%
ALAKUKO	16.6	7.2	44%	11.8	71%
ABULE-IROKO	14.3	6.9	49%	11.2	78%
BOOKS	7.1	5.4	77%	6.3	90%
ANTHONY	21.0	6.0	29%	6.0	29%
OWORO-IFAKO	7.8	4.3	55%	6.6	84%
HOSPITAL	11.8	6.0	51%	11.7	99%
LADILAC	9.5	5.7	61%	8.6	91%
OWORO	6.8	3.5	52%	6.5	97%
PEDRO	13.4	6.3	47%	7.6	57%
BARIGA	10.4	5.9	56%	8.8	85%
GBAGADA	12.5	5.8	47%	6.3	51%
CAC	11.8	6.4	54%	6.7	57%
OGUDU ROAD	13.8	5.6	41%	8.2	59%
OGUDU-EXPRESS	13.1	6.7	51%	4.1	31%
ALAPERE	7.7	4.0	52%	1.8	23%
ORIOLA	8.0	4.7	58%	7.5	94%
BALOGUN	9.4	6.2	66%	8.1	86%
SOLUYI	10.0	5.2	52%	5.0	50%
MILITARY	14.8	5.9	40%	10.0	68%

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Feeder Name	Transformation Capacity (MVA)	2019 Max Load (MVA)	2019 Loading (%)	2024 Max Load (MVA)	2024 Loading (%)
APATA	8.4	4.9	58%	5.1	61%
ADUROSAKIN	9.9	5.0	51%	5.2	53%

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J. 2 33kV Voltage Level Analysis

Table 51: 33/11kV Power Transformers Loading Analysis in 2019 and 2024

			2019			2024		
Injection Substation	Transformer Name	Name Plate Capacity (MVA)	Max Demand (MVA)	Cap Ratio (%)	N-0 Relief	Max Demand (MVA)	Cap Ratio (%)	N-0 Relief
NEW YABA	NEW YABA 2X15MVA - T1	15.00	3.2	22%			40%	
NEW YABA	NEW YABA 2X15MVA - T2	15.00	4.6	31%		5.7	38%	
AKOKA	AKOKA T3 15MVA	15.00	15.3	102%	1 x 15 MVA	19.6	130%	1 x 15 MVA
OPEBI	OPEBI 1X15MVA -T1	15.00	13.2	88%	1 x 15 MVA	20.6	137%	1 x 15 MVA
ALAUSA	ALAUSA 3X15MVA - T4	15.00	11.6	78%		17.9	119%	ISS Required
ALAUSA	ALAUSA 3X15MVA - T5	15.00	9.2	62%		32.1	214%	ISS Required
ISHERI	ISHERI 1X15MVA - T1	15.00	8.9	60%		16.1	107%	1 x 15 MVA
OLOWORA	OLOWORA 1X5MVA - T1	15.00	8.1	54%		9.3	62%	
ALAUSA	ALAUSA 3X15MVA - T6	15.00	8.0	53%		19.5	130%	ISS Required
MAGODO	MAGODO 2X15MVA - T1	15.00	10.7	71%		12.7	85%	1 x 15 MVA
MAGODO	MAGODO 2X15MVA - T2	15.00	6.3	42%		10.9	73%	

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			2019			2024		
Injection Substation	**Transformer Name**	**Name Plate Capacity (MVA)**	**Max Demand (MVA)**	**Cap Ratio (%)**	**N-0 Relief**	**Max Demand (MVA)**	**Cap Ratio (%)**	**N-0 Relief**
SECRETARIAT	SECRETARIAT 2X15MVA - T1	15.00	14.2	95%	ISS Required	20.8	138%	ISS Required
SECRETARIAT	SECRETARIAT 2X15MVA - T2	15.00	10.2	68%		19.7	131%	ISS Required
OJODU	OJODU 2X15MVA - T1	15.00	11.9	79%		19.5	130%	1 x 15 MVA
OJODU	OJODU 2X15MVA - T2	15.00	12.7	84%	1 x 15 MVA	18.4	123%	1 x 15 MVA
ALIMOSHO	ALIMOSHO T4 15MVA -T1	15.00	16.8	112%	ISS Required	23.4	156%	ISS Required
ALIMOSHO	ALIMOSHO T6 15MVA -T1	15.00	12.6	84%	ISS Required	18.8	125%	ISS Required
AGEGE	AGEGE 3X15MVA - T2	15.00	18.7	125%	ISS Required	19.2	128%	ISS Required
AGEGE	AGEGE 3X15MVA - T3	15.00	17.6	117%	ISS Required	29.1	194%	ISS Required
ALIMOSHO	ALIMOSHO T8 15MVA - T1	15.00	12.5	83%	ISS Required	20.2	135%	ISS Required
NEW GOWON	NEW GOWON 1X15MVA - T1	15.00	14.1	94%	1 x 15 MVA	29.3	195%	1 x 15 MVA
AGEGE	AGEGE 3X15MVA - T1	15.00	13.5	90%	ISS Required	22.0	146%	ISS Required
EKORO	EKORO 2X15MVA - T1	15.00	24.5	164%	ISS Required	39.9	266%	1 x 15 MVA
ADARANIJO	ADARANIJO 1X15MVA - T1	15.00	16.1	107%	1 x 15 MVA	30.3	202%	1 x 15 MVA

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			2019			2024		
Injection Substation	Transformer Name	Name Plate Capacity (MVA)	Max Demand (MVA)	Cap Ratio (%)	N-0 Relief	Max Demand (MVA)	Cap Ratio (%)	N-0 Relief
TOWER ALUMINIUM	TOWER ALUMINIUM 1X7.5MVA - T1	7.50	0.0			0.0		ISS Required
AMUWO	AMUWO 2X15MVA - T1	15.00	5.1	34%		4.7	31%	
AMUWO	AMUWO 2X15MVA - T2	15.00	13.5	90%	1 x 15 MVA	15.5	103%	1 x 15 MVA
AIYETORO	AIYETORO 1X15MVA - T1	15.00	12.0	80%		25.6	171%	1 x 15 MVA
AYOBO	AYOBO 1X15MVA - T1	15.00	13.1	87%	1 x 15 MVA	19.5	130%	1 x 15 MVA
ALAJA	ALAJA 1X15MVA - T1	15.00	6.0	40%		10.2	68%	
ABESAN	ABESAN 2X15MVA -T1	15.00	18.8	126%	1 x 15 MVA	35.2	234%	1 x 15 MVA
ABESAN	ABESAN 2X15MVA -T2	15.00	12.9	86%	1 x 15 MVA	17.8	119%	1 x 15 MVA
ABULE TAYLOR	ABULE TAYLOR 1X15MVA - T1	15.00	13.3	89%	1 x 15 MVA	27.5	183%	1 x 15 MVA
AMIKANLE	AMIKANLE 1X15MVA - T1	15.00	14.4	96%	1 x 15 MVA	18.4	123%	1 x 15 MVA
OKE AFA	OKE AFA 3X15MVA - T1	15.00	12.9	86%	ISS Required	19.1	128%	ISS Required
OKE AFA	OKE AFA 3X15MVA - T2	15.00	18.3	122%	ISS Required	20.0	134%	ISS Required
OKE AFA	OKE AFA 3X15MVA - T3	15.00	19.6	131%	ISS Required	27.7	185%	ISS Required
AGODO EGBE	AGODO EGBE 1X15MVA - T1	15.00	11.0	73%		14.5	96%	1 x 15 MVA

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			2019			2024		
Injection Substation	Transformer Name	Name Plate Capacity (MVA)	Max Demand (MVA)	Cap Ratio (%)	N-0 Relief	Max Demand (MVA)	Cap Ratio (%)	N-0 Relief
IGANDO	IGANDO 2X15MVA - T1	15.00	13.9	93%	1 x 15 MVA	20.6	137%	1 x 15 MVA
IGANDO	IGANDO 2X15MVA - T2	15.00	19.4	129%	1 x 15 MVA	27.9	186%	1 x 15 MVA
IJEGUN	IJEGUN 2X15MVA - T1	15.00	12.8	85%	1 x 15 MVA	20.6	137%	1 x 15 MVA
IJEGUN	IJEGUN 2X15MVA - T2	15.00	15.6	104%	1 x 15 MVA	23.9	160%	1 x 15 MVA
SHASHA	SHASHA 1X15MVA - T1	15.00	16.0	107%	1 x 15 MVA	22.9	153%	1 x 15 MVA
BOLORUNPELU	BOLORUNPELU 3X15MVA - T1	15.00	18.6	124%	1 x 15 MVA	32.8	219%	1 x 15 MVA
BOLORUNPELU	BOLORUNPELU 3X15MVA - T3	15.00	12.0	80%		24.3	162%	1 x 15 MVA
OKELETU	OKELETU 1X15MVA - T1	15.00	5.0	33%		8.7	58%	
SABO	SABO 2X15MVA - T1	15.00	20.4	136%	1 x 15 MVA	34.4	230%	1 x 15 MVA
SABO	SABO 2X15MVA - T2	15.00	23.4	156%	1 x 15 MVA	40.4	270%	1 x 15 MVA
EBUTE	EBUTE 1X15MVA - T1	15.00	12.7	84%	1 x 15 MVA	22.9	152%	1 x 15 MVA
OWUTU	OWUTU 2X15MVA - T1	15.00	10.3	69%		17.3	115%	1 x 15 MVA
OWUTU	OWUTU 2X15MVA - T2	15.00	15.7	104%	1 x 15 MVA	25.3	169%	1 x 15 MVA
EPE	EPE 1 X15MVA - T1	15.00	8.1	54%		18.5	124%	1 x 15 MVA

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			2019			2024		
Injection Substation	Transformer Name	Name Plate Capacity (MVA)	Max Demand (MVA)	Cap Ratio (%)	N-0 Relief	Max Demand (MVA)	Cap Ratio (%)	N-0 Relief
IGBOGBO	IGBOGBO 2X15MVA - T1	15.00	13.3	89%	1 x 15 MVA	19.7	131%	1 x 15 MVA
IGBOGBO	IGBOGBO 2X15MVA - T2	15.00	11.5	77%		14.1	94%	1 x 15 MVA
ILUPEJU	T1 ILUPEJU 15MVA	15.00	3.7	25%		4.6	31%	
IGBOBI	IGBOBI 3X15MVA - T2	15.00	11.0	73%		15.2	101%	ISS Required
IGBOBI	IGBOBI 3X15MVA - T3	15.00	14.4	96%	ISS Required	28.9	193%	ISS Required
ILUPEJU	T3 ILUPEJU 15MVA -T1	15.00	16.8	112%	ISS Required	21.9	146%	ISS Required
ILUPEJU LOCAL	ILUPEJU LOCAL 1X15MVA - T1	15.00	13.1	88%	1 x 15 MVA	26.2	175%	1 x 15 MVA
MUSHIN	MUSHIN 1X15MVA - T1	15.00	5.6	37%		7.6	50%	
ILUPEJU	T4 ILUPEJU	15.00	9.2	61%		5.1	34%	
AJAO	AJAO 2X15MVA - T1	15.00	11.6	77%		18.1	121%	1 x 15 MVA
AJAO	AJAO 2X15MVA - T2	15.00	8.5	57%		12.7	85%	1 x 15 MVA
MAFOLUKU	MAFOLUKU 1X15MVA - T1	15.00	10.0	67%		16.2	108%	1 x 15 MVA
ALASIA	ALASIA 1X15MVA - T1	15.00	16.6	111%	1 x 15 MVA	23.4	156%	1 x 15 MVA
NITEL	NITEL T1 15MVA - T1	15.00	5.3	36%		9.4	63%	
ISOLO	ISOLO T3-15MVA - T1	15.00	8.2	55%		14.2	94%	1 x 15 MVA

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			2019			2024		
Injection Substation	**Transformer Name**	**Name Plate Capacity (MVA)**	**Max Demand (MVA)**	**Cap Ratio (%)**	**N-0 Relief**	**Max Demand (MVA)**	**Cap Ratio (%)**	**N-0 Relief**
ITIRE	ITIRE 3X15MVA - T1A	15.00	12.9	86%	ISS Required	21.8	145%	ISS Required
ITIRE	ITIRE 3X15MVA - T1B	15.00	10.8	72%		20.2	135%	ISS Required
AGO OKOTA	AGO OKOTA 2X15MVA - T1	15.00	13.5	90%	1 x 15 MVA	21.2	141%	1 x 15 MVA
AGO OKOTA	AGO OKOTA 2X15MVA - T2	15.00	9.7	65%		13.3	89%	1 x 15 MVA
ITIRE	ITIRE 3X15MVA - T3	15.00	9.3	62%		18.4	122%	ISS Required
WASIMI	WASIMI 2X15MVA - T1	15.00	16.9	113%	1 x 15 MVA	25.1	167%	1 x 15 MVA
WASIMI	WASIMI 2X15MVA - T2	15.00	9.8	65%		14.9	99%	1 x 15 MVA
SECRETARIAT	SECRETARIAT 2X15MVA (dual supply)	15.00	0.0			0.0		ISS Required
MARYLAND	MARYLAND 3X15MVA - T1	15.00	15.8	105%	ISS Required	20.9	139%	ISS Required
MARYLAND	MARYLAND 3X15MVA - T3	15.00	14.9	100%	ISS Required	24.8	165%	ISS Required
AJEGUNLE	AJEGUNLE 1X15MVA - T1	15.00	5.2	35%		4.9	32%	
ALAPERE	ALAPERE 1X15MVA - T1	15.00	10.3	69%		15.0	100%	1 x 15 MVA
PTC	PTC 2X15MVA, 1X7.5MVA - T1	15.00	6.2	42%		6.6	44%	
PTC	PTC 2X15MVA, 1X7.5MVA - T2	15.00	7.5	50%		11.7	78%	

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			2019			2024		
Injection Substation	**Transformer Name**	**Name Plate Capacity (MVA)**	**Max Demand (MVA)**	**Cap Ratio (%)**	**N-0 Relief**	**Max Demand (MVA)**	**Cap Ratio (%)**	**N-0 Relief**
PTC	PTC 2X15MVA, 1X7.5MVA - T3	15.00	11.6	77%		15.5	103%	ISS Required
ADEKUNLE FAJUYI	ADEKUNLE FAJUYI 1X15MVA -T1	15.00	7.9	52%		8.4	56%	
MARYLAND	MARYLAND 3X15MVA - T2	15.00	10.9	73%		17.9	119%	ISS Required
ODOGUNYAN	ODOGUNYAN 2X15MVA - T1	15.00	12.5	83%	1 x 15 MVA	21.6	144%	1 x 15 MVA
ODOGUNYAN	ODOGUNYAN 2X15MVA - T2	15.00	15.7	105%	1 x 15 MVA	27.5	183%	1 x 15 MVA
ADENIYI JONES	ADENIYI JONES 1X15MVA - T1	15.00	7.1	47%		11.2	74%	
IJAIYE-OJOKORO	IJAIYE-OJOKORO 2X15MVA - T1	15.00	18.7	125%	1 x 15 MVA	21.1	141%	1 x 15 MVA
IJAIYE-OJOKORO	IJAIYE-OJOKORO 2X15MVA - T2	15.00	6.8	45%		7.1	48%	
BECKLEY	BECKLEY 1X15MVA - T1	15.00	9.9	66%		14.3	95%	1 x 15 MVA
MANGORO	MANGORO 3X15MVA - T1	15.00	16.7	111%	1 x 15 MVA	27.9	186%	1 x 15 MVA
PTC	PTC 2X15MVA, 1X7.5MVA (DUAL SUPPLY)	15.00	0.0			0.0		ISS Required
OGBA	OGBA T2 15MVA -T2	15.00	14.6	97%	ISS Required	25.9	172%	ISS Required
OGBA	OGBA T3 15MVA -T3	15.00	10.7	71%		17.1	114%	ISS Required

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			2019			2024		
Injection Substation	**Transformer Name**	**Name Plate Capacity (MVA)**	**Max Demand (MVA)**	**Cap Ratio (%)**	**N-0 Relief**	**Max Demand (MVA)**	**Cap Ratio (%)**	**N-0 Relief**
OGBA	OGBA T1 15MVA -T1	15.00	12.3	82%	ISS Required	13.1	87%	
OKE-IRA	OKE-IRA 2X15MVA - T1	15.00	11.2	75%		17.6	117%	1 x 15 MVA
OKE-IRA	OKE-IRA 2X15MVA - T2	15.00	16.5	110%	1 x 15 MVA	23.7	158%	1 x 15 MVA
LAMBE	LAMBE 1X15MVA - T1	15.00	12.2	81%	1 x 15 MVA	25.1	167%	1 x 15 MVA
ASORE	ASORE 1X15MVA - T1	15.00	13.1	87%	1 x 15 MVA	18.2	122%	1 x 15 MVA
IJU	IJU 2X15MVA - T1	15.00	20.5	137%	1 x 15 MVA	41.0	273%	1 x 15 MVA
IJU	IJU 2X15MVA - T2	15.00	13.7	91%	1 x 15 MVA	26.9	179%	1 x 15 MVA
OPE ILU	OPE ILU 1X15MVA - T1	15.00	12.1	81%	1 x 15 MVA	24.3	162%	1 x 15 MVA
YIDI	YIDI 1X15MVA - T1	15.00	14.1	94%	1 x 15 MVA	30.2	201%	1 x 15 MVA
YUSUF	YUSUF 1X7.5MVA - T1	7.50	5.0	66%		7.4	99%	1 x 7.5 MVA
YUSUF	YUSUF 1X15MVA - T2	15.00	10.9	73%		20.8	139%	1 x 15 MVA
ILAPO	ILAPO 1X2.5MVA	2.50	6.7	266%	1 x 7.5 MVA	10.2	408%	1 x 15 MVA
ABULE-IROKO	ABULE-IROKO 1X15MVA - T1	15.00	17.1	114%	1 x 15 MVA	29.3	195%	1 x 15 MVA

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			2019			2024		
Injection Substation	**Transformer Name**	**Name Plate Capacity (MVA)**	**Max Demand (MVA)**	**Cap Ratio (%)**	**N-0 Relief**	**Max Demand (MVA)**	**Cap Ratio (%)**	**N-0 Relief**
OWORO	OWORO 3X15MVA - T1	15.00	14.8	99%	ISS Required	21.9	146%	ISS Required
OWORO	OWORO 3X15MVA - T2	15.00	15.1	101%	ISS Required	22.8	152%	ISS Required
OWORO	OWORO 3X15MVA - T3	15.00	11.3	75%		14.8	99%	
NEW OWORO	NEW OWORO 1X15MVA - T1	15.00	0.0			0.0		ISS Required
OGUDU	OGUDU 3X15MVA- T1	15.00	11.9	79%		14.9	99%	
OGUDU	OGUDU 3X15MVA- T2	15.00	12.7	85%	ISS Required	12.3	82%	
OGUDU	OGUDU 3X15MVA- T3	15.00	10.5	70%		13.1	87%	
IGBOBI	IGBOBI 3X15MVA - T1	15.00	13.6	91%	ISS Required	17.5	117%	ISS Required

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Table 52: Injection Substations Analysis

Injection Substation	2019 Relief Injection Substations Required	2024 Relief Injection Substations Required
NEW YABA		
AKOKA		
OPEBI		
ALAUSA		1
ISHERI		
OLOWORA		
MAGODO		
SECRETARIAT	1	1
OJODU		
ALIMOSHO	1	1
AGEGE	1	1
NEW GOWON		
EKORO		
ADARANIJO		
TOWER ALUMINIUM		
AMUWO		
AIYETORO		
AYOBO		
ALAJA		
ABESAN		
ABULE TAYLOR		
AMIKANLE		
OKE AFA	1	1
AGODO EGBE		
IGANDO		
IJEGUN		
SHASHA		
BOLORUNPELU		
OKELETU		
SABO		
EBUTE		
OWUTU		
EPE		
IGBOGBO		
ILUPEJU	1	1

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Injection Substation	2019 Relief Injection Substations Required	2024 Relief Injection Substations Required
IGBOBI	1	1
ILUPEJU LOCAL		
MUSHIN		
AJAO		
MAFOLUKU		
ALASIA		
NITEL		
ISOLO		
ITIRE	1	1
AGO OKOTA		
WASIMI		
MARYLAND	1	1
AJEGUNLE		
ALAPERE		
PTC		1
ADEKUNLE FAJUYI		
ODOGUNYAN		
ADENIYI JONES		
IJAIYE-OJOKORO		
BECKLEY		
MANGORO		
OGBA	1	1
OKE-IRA		
LAMBE		
ASORE		
IJU		
OPE ILU		
YIDI		
YUSUF		
ILAPO		
ABULE-IROKO		
OWORO	1	1
NEW OWORO		
OGUDU	1	1
TOTAL	**11**	**13**

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Table 53: 33kV Feeders Overloading Analysis

33kV Feeders	2019 Overloading (MVA)	2024 Overloading (MVA)
NEW YABA	-	-
AKOKA 33kV	-	-
OPEBI 33kV	-	-
T4 ALAUSA	-	-
T5 ALAUSA	-	5.9
OPIC	-	13.0
T6 ALAUSA	-	-
MAGODO	-	30.2
NEW ALAUSA	-	19.1
OJODU 33kV	-	16.1
T4 IPAJA	-	-
T6 IPAJA	-	-
AGEGE 33kV	9.4	25.5
T8 IPAJA	-	-
ADIYAN 33kV	-	3.1
IPAJA-EKORO	10.3	32.3
TOWER ALUMINIUM	-	17.3
FESTAC 1	-	-
AMUKOKO	-	6.4
HONGXING 1	-	-
HONGXING 2	-	-
AIYETORO	1.0	28.0
ABESAN 33kV	5.6	26.1
ABULE TAYLOR	-	7.9
AMIKANLE	-	-
AIRPORT EJIGBO	-	-
OKE AFA I	4.6	17.6
OKE AFA II	-	16.5
AGODO 33kV	5.9	17.6
EGBE	39.9	74.1
SHASHA 33kV	-	-
BOLORUNPELU	6.2	34.5
IJEDE	7.4	20.5
T1 SABO	-	8.3
UNTL	-	-
INDUSTRIAL 33kV	6.9	8.8
T2 SABO	-	14.3
DANGOTE	-	-

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33kV Feeders	2019 Overloading (MVA)	2024 Overloading (MVA)
FAKALE	-	-
IBESHE	-	6.9
OWUTU	18.8	39.4
PULKIT	-	-
AGBOWA	6.7	25.5
IGBOGBO 33kV	12.7	30.2
SPINTEX	-	-
T1 ILUPEJU	-	-
ILUPEJU IGBOBI	-	18.3
T3 ILUPEJU	-	-
ILUPEJU BYEPASS	-	0.6
T4A ILUPEJU	-	-
AFPRINT	-	-
AJAO	1.5	18.9
PTC ISOLO	-	2.9
NITEL	-	-
AIRPORT ISOLO	-	-
ASWANI	-	-
ISOLO LOCAL	-	-
AGO OKOTA 2	-	-
ITIRE 1	-	15.7
AGO OKOTA 1	-	13.4
T3 ITIRE	-	-
MARYLAND ALAUSA	-	11.6
T1 MARYLAND	-	-
T3 MARYLAND	-	-
MARYLAND AJEGUNLE	-	5.2
MARYLAND PTC	7.7	16.6
T2 MARYLAND	-	-
CHIKI CHIKI	-	-
MEGA STEEL	-	-
AGBEDE	-	-
ODOGUNYAN	0.9	21.5
FEEDER 2	-	-
UNIVERSAL STEEL	-	-
ABEOKUTA EXPRESS 33kV	11.6	30.9
DUNLOP	-	3.6
OLD IJU	-	-
PTC EXPRESS	-	-
FEEDER 8	7.3	27.3

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33kV Feeders	2019 Overloading (MVA)	2024 Overloading (MVA)
SANKYO	-	-
CISCO	1.9	15.8
FESTAC II INTERFACE	-	-
LAMBE	-	-
AKUTE 33kV	-	6.4
NEW IJU	8.2	40.1
YIDI	-	7.4
AMJE	17.4	41.6
T1 OWORO	-	0.0
T2 OWORO	-	-
T3 OWORO	-	-
NEW OWORO	-	-
OGUDU 1	7.7	22.9
OGUDU 2	-	-
OWORO-IGBOBI	-	-
Total	**199.7**	**865.6**
Feeder Count	**22**	**46**

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J. 3 TCN Station Analysis

Table 54: Load Forecast by TCN Station

TCN	TCN Transformer Capacity (MVA)	TCN Transformer Capability (MW)	Connected DTR Capacity (MVA)	Demand (MW)					
Substation	**Current**	**Current**	**Current**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
AKOKA	80	50	86	22	24	25	26	28	30
ALAUSA	135	86	375	102	131	153	175	197	219
ALIMOSHO	230	166	355	122	138	152	167	182	196
AMUWO	120	43	66	41	42	45	47	50	53
AYOBO	120	86	201	76	98	106	115	124	133
EJIGBO	400	209	385	172	200	216	233	250	268
IKORODU	280	202	712	276	298	316	334	353	371
ILUPEJU	105	63	227	54	65	72	80	88	95
ISOLO	180	108	137	61	64	71	78	85	93
ITIRE	130	51	161	56	68	74	80	86	92
MARYLAND	90	87	338	95	104	114	123	133	143
ODOGUYAN	120	86	158	55	62	66	69	73	76
OGBA	225	151	432	125	134	146	158	171	183
OJO	60	54	6	2	3	4	4	5	6
OKE-ARO	120	86	260	75	97	104	111	119	126
OTTA	60	43	81	35	37	41	46	50	54
OWORO	120	86	196	76	76	84	93	102	111
Total	**2,575**	**1,657**	**4,176**	**1,444**	**1,641**	**1,790**	**1,941**	**2,094**	**2,249**

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