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Transmission Costing Requirements Study

For Transmission Company of Nigeria (TCN)

DRAFT REPORT

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Contents Page

List of abbreviations

AMR	Automatic Meter Reading
bn	Billion (a thousand million)
BoQ	Bill-of-Quantity
C+F	Cost and Freight
Capex	Capital Expenditure
Disco	Distribution Company
E	Erection
EIA	Environmental Impact Assessment
EPC	Engineering, Procurement and Construction
FGN	Federal Government of Nigeria
FMENV	Federal Ministry of Environment
Genco	Generation Company
GIS	Geographical Information System
GW	Giga- Watts
HR	Human Resources
IFC	International Finance Corporation
IT	Information Technology
Km	Kilometres
kV	Kilo-Volts
LTE	Local Transportation and Erection
MIS	Management Information System
MO	Market Operator
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
MW	Mega-Watts
MYTO	Multi-Year Tariff Order
NBET	Nigerian Bulk Electricity Trading Limited
NIPP	National Integrated Power Project
NERC	Nigerian Electricity Regulatory Commission

NGN	Nigerian Naira
Opex	Operating Expenditure
RTU	Remote Terminal Unit
SC	Successor Company
SCADA	Supervisory Control And Data Acquisition
SIA	Social Impact Assessment
SO	System Operator
TCN	Transmission Company of Nigeria
TSP	Transmission Service Provider
tn	Trillion (a thousand billion)
USD	United States Dollar
V	Volts

Transmission Costing Requirements Study
For Transmission Company of Nigeria (TCN)

Executive Summary

The Transmission Company of Nigeria (TCN) plays a key role in the electricity sector. At present the level of power sent out is transmission constrained. If, as is intended, the establishment of a power market and the privatisation of GenCos leads to an increase in generation capacity, this problem will become even more acute. This study is intended to do estimate TCN's cash requirements, looking at capex and opex over a ten year period (2014-2023), to enable TCN to start to fulfil its crucial role.

Approach

The approach to this study has involved a number of strands, namely:

- To obtain and verify data on the existing transmission network;
- To outline a viable expanded network that can realistically be achieved by 2026. An extended horizon beyond the end of the study period has been used to fully estimate investment requirements up to 2023 given lead-times of capital projects;
- To estimate the costs of specific transmission projects required under our viable expanded network based on actual costs obtained from NIPP and TCN;
- To estimate refurbishment costs and maintenance costs of existing assets;
- To estimate SO and MO capex requirements; and
- To estimate TSP, SO and MO operating costs based on a functional analysis of their staffing requirements.

Proposed network by 2026

NERC's current tariff model (MYTO2) is the reference point for all tariff and revenue analysis. Hence in assessing transmission costs (particularly needed investment) the main load growth case must be closely related to the load predictions in the MYTO2 model. Given buyers of Gencos and Discos have largely based their numbers on MYTO2 this also means that our load predictions are consistent with those used in Successor Company (SC) business plans.

We based the distribution of load on TCN's own 10GW model which provides load distribution by substation and verified these numbers against MYTO2 disco load allocations and TCN disco stress tests.

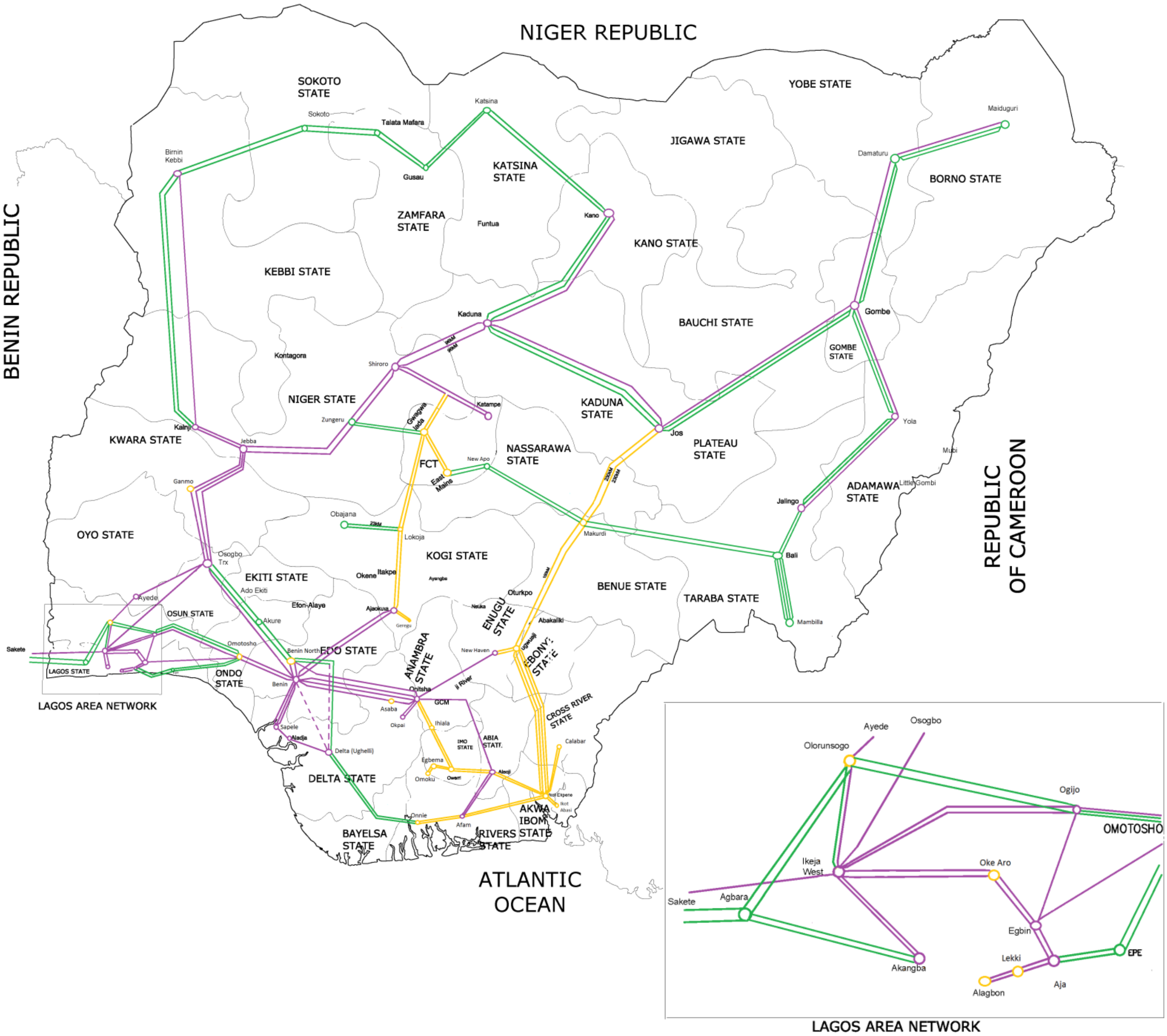
Following various adjustments (discussed in section 3.2) the final load growth (peak delivery to discos) is as follows.

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
MW	4,542	5,678	6,813	7,631	8,429	9,272	9,735	10,222	10,733	11,270	11,833	12,425	13,046	13,698

Expected 330kV network in 2026

The 330kV network we consider required to meet 13.7GW in 2026 is given in the maps below. This is based on TCN's own 10GW model but expanded to meet the additional demand and revised where we have considered appropriate. Notable revisions have included around Lagos due to congestion and the addition of lines and substations related to the inclusion of Mambilla and Zengeru.

The purple circuits are existing TCN circuits (which includes those under construction and expected to be completed in 2013); yellow circuits are NIPP circuits; and green circuits are new circuits required to meet the 13.7GW demand.



The transformer loading from the initial load flow was recorded and analysed and where the load was too high to provide N-1 security (i.e. where one transformer trips the remaining transformers do not overload) 330/132kV transformers were added appropriately. Where more than one transformer was added the timing of the event was staggered.

132kV lines and below

We were not able to take the same detailed approach to 132kV voltage level and below as we did for the 330kV voltage level. This is because firstly, current TCN planning does not reach this level, and secondly, to plan accurately as this level coordination with Disco planning is required. We therefore took a generic approach, as follows:

- Assessed the need for additional 132/33kV transformation capacity in each TCN region.
- Assessed the number of additional standardised 132/33kV substations required and when they will be needed.
- Assumed that each new standardised 132/33 substation will be fed by a new radial standardised 132kV line, the length of which would vary by TCN region.
- Included substation expansion works to existing 330/132kV substations where the new radial standardised 132kV line connects to the existing network.

TSP capex and maintenance model

The following costs were identified and modelled:

- New build – The construction of new assets on greenfield sites.
- Substation expansion – The addition of new circuits and/or new transformers at existing voltages at existing substations.
- Refurbishment – A five year line refurbishment programme is included for all existing assets given chronically poor maintenance over a long period. This involves: either, the overhaul of existing components keeping specifications constant; or, the replacement of existing components keeping specifications constant where refurbishment is not considered economical.
- Annual maintenance costs – Estimated on the basis of maintaining suitably refurbished lines. These are included throughout for existing assets and from the year after commissioning for new assets (including NIPP assets).
- Purchase of NIPP assets - Estimating the cost to the TSP of building these assets from scratch provides an upper bound to the cost TSP should rationally be willing to pay for such assets if required to make such a payment. This payment is not period specific and has therefore been included as a one-off cost to be included or excluded as required.

Unit cost data

Over the last decade NIPP has by far been the largest constructor of transmission assets. We have been able to obtain actual bill-of-quantity (BoQ) costs from NIPP providing assurance that these are prices actually paid for transmission assets in Nigeria. A number of unit cost assumptions have been further improved following discussions with TSP.

The structure of NIPP BoQ costs has informed our costing structure. On a NIPP BoQ for each line item costs are given for:

- “Cost and Freight (C+F)” – The cost of purchasing an item at the port of entry in Nigeria. Shipping and customs charges are therefore included here. Units are US Dollars (USD);
- “Erection (E)” – The cost of erection in foreign currency (USD);
- “Local Transportation and Erection (LTE)” – The cost of transportation to site and erection in Nigerian Naira (NGN).

Ancillary services

Ancillary services are provided by generators to ensure that the power system is operated at stable frequency and voltage and that it can be returned from a complete system collapse. This is a major operating cost item for the system operator. The three services and their cost drivers are:

1. Frequency control and reserve provision – This requires operating generating units not fully loaded which decreases their efficiency. It also implies increased wear and tear of continually increasing and decreasing output, which increases maintenance costs.
2. Voltage Control and MVAR – This requires operating generating units at higher rotor, stator and transformer currents to provide or absorb MVAR in order to control system voltages. This increases losses and maintenance costs.
3. Black Start – In order to start the system from dead power stations must have auxiliary generation capacity and associated batteries. This capability must be tested regularly and staff must be trained in the process and procedures; this leads to on-going costs for the generator that need to be paid for, irrespective of whether the capability is utilized. When a black start occurs the generator must also be paid for the costs of doing it.

SO and MO capital requirements

We identified six areas for SO and MO capital investment, namely:

- SCADA;
- Telecoms;

- New National Control Centre;
- Planning specific IT investment (particularly software licences);
- Settlement System;
- Automatic Meter Reading (AMR) System.

A detailed discussion of these items is provided in section 6.

Operating cost requirements (exc. TSP maintenance)

Operating costs (excluding TSP asset maintenance) is in many ways the hardest area to calculate financial requirements given a lack of relevant benchmarking information. The following sources were considered and dismissed as part of the research for this study:

- Existing TCN operating budgets – While directly relevant to the organisation the existing operating budgets are largely not appropriate to the way TCN should be operating in future. For example we consider staffing levels to be too high but salaries too low for TCN divisions to operate in future. Despite a very large amount of information (hundreds if not thousands of budget lines) in TCN operating budgets, it is not clear if they correctly allow for expected TCN future functions.
- International benchmarks – Operating costs are largely locally driven (particularly staff costs) so relevance is somewhat limited. In addition even relatively minor variations in sector structures and allocations of responsibilities can have large impacts on the distribution of operating costs to various sector participants.

As a result of these limitations we have instead undertaken a relatively simplistic estimation of costs that outputs numbers we consider reasonable. The estimation was undertaken by considering:

- Functions of each TCN division and the professional staffing complement required for each function;
- An estimated number of support staff required per professional staff member;
- Generic organisational costs based upon the staffing complement (professional and support) for each TCN division;
- Division specific costs related to their intended function.

In order to allow for any future division or otherwise of TCN (as well as further simplifying the model) support functions such as IT, HR and legal are costed within each of the three divisions. We have therefore made no allowance for non-division specific costs.

Findings

Our high-level findings are presented below. When interpreting these findings the following should be taken into consideration.

- All numbers are given in 2013 constant prices.
- Costs in foreign currency (USD) and local currency (NGN) are calculated and stated completely independently. USD values represent a different set of costs to those costs represented by the NGN values. This avoids having to make foreign exchange assumptions and allows for differing treatment of inflation by currency on conversion to nominal values.

	USD (Constant 2013 prices)	NGN (Constant 2013 prices)
Total (2014-2023)	**6,505,424k**	**622,188m**
TSP Capital Expenditure	**3,919,952k**	**245,573m**
New Lines	1,254,397k	175,536m
New Substations	1,093,634k	23,549m
Existing Substations Expansion	587,030k	15,826m
Line Refurbishment	199,551k	9,490m
Substation Refurbishment	785,340k	21,171m
Other capital costs	841k	-
TSP Operating Expenditure	**1,386,367k**	**104,925m**
Line Maintenance	443,772k	44,444m
Substation Maintenance	837,459k	23,754m
Staff costs	-	24,511m
Other costs	105,135k	12,217m
SO Capital Expenditure	**309,382k**	-
SO Operating Expenditure	**103,380k**	**87,483m**
Staff costs	-	73,032m
Other costs	103,380k	14,451m
MO Capital Expenditure	**11,000k**	-
MO Operating Expenditure	**3,500k**	**8,536m**
Staff costs	-	7,064m
Other costs	3,500k	1,473m
NIPP Buyout (Upper Bound)	**771,843k**	**68,960m**
Lines	348,696k	58,108m
Substations	423,147k	10,851m
Ancillary Services	-	**106,711m**

Assuming a NGN/USD exchange rate of 155 implies the following:

- total cost over the ten year period is around USD10.5bn;
- cost for 2014 are around USD1.4bn;
- average cost per year over the first five years (2014-18) is around USD1.1bn;
- average cost per year over the latter five years (2019-23) is around USD750m.
- one-off (non-period specific costs) relating to the purchase of NIPP assets is around USD1.2bn.

A detailed breakdown is provided in Section 8.

Transmission Costing Requirements Study
For Transmission Company of Nigeria (TCN)

1 Introduction

The Transmission Company of Nigeria (TCN) plays a key role in the electricity sector. At present the level of power sent out is transmission constrained. If, as is intended, the establishment of a power market and the privatisation of gencos leads to an increase in generation capacity, this problem will become even more acute.

Significant amounts of investment are needed in the transmission line business of the Transmission Company of Nigeria (TCN) if it is going to meet expected future loads. There are currently discussions at various levels of the Federal Government of Nigeria (FGN) on options for financing mechanisms. A number of 'back of the envelope' calculations have been conducted on the level of capex required (including by NIAF) but a more detailed analysis of both capex and opex is required to enable TCN to make the case to NERC and others for additional funding.

This study is intended to do this analysis, looking at capex and opex over a ten year period (2014-2023).

1.1 Approach

The approach to this study has involved a number of strands, namely:

- To obtain and verify data on the existing transmission network;
- To outline a viable expanded network that can realistically be achieved by 2026. An extended horizon beyond the end of the study period has been used to fully estimate investment requirements up to 2023 given lead-times of capital projects;
- To estimate the costs of specific transmission projects required under our viable expanded network based on actual costs obtained from NIPP and TCN;
- To estimate refurbishment costs and maintenance costs of existing assets;
- To estimate SO and MO capex requirements; and
- To estimate TSP, SO and MO operating costs based on a functional analysis of their staffing requirements.

1.2 Structure of report

The remainder this report covers the following topics:

- Section 2 provides details on our data sources for the existing network;
- Section 3 provides details of the loadflow study conducted to determine transmission requirements by 2026;
- Section 4 provides details of the model and assumptions used to determine TSP capex and maintenance requirements;
- Section 5 provides details of the model and assumptions used to determine ancillary services costings;
- Section 6 provides details of SO and MO capital requirements and the methodology for estimation;
- Section 7 provides details of operating requirements (excluding TSP maintenance) for TSP, SO and MO;
- Section 8 provides summary findings.

1.3 Constant prices

All costs are in 2013 constant prices in this report unless otherwise stated.

1.4 Treatment of NIPP assets

There remains considerable uncertainty over future transmission funding (although there seems to be consensus that the current mechanism for transmission funding through the Federal Government allocation process is inadequate). The role NIPP will play, if any, in future funding arrangements is also unclear as is the process, and basis, by which the TSP will acquire NIPP transmission assets. While these issues are outside the scope of this report they do have significant impact on the timing of funding requirements. For the purposes of this report we have assumed:

- Any existing or currently under construction NIPP transmission asset will, at some point, be handed over to the TSP. Estimating the cost to the TSP of building these assets from scratch provides an upper bound to the cost TSP should rationally be willing to pay for such assets if required to make such a payment. This payment is not period specific and has therefore been included as a one-off cost to be included or excluded as required.
- All future assets will be constructed by TCN. This assumption is not intended as a judgement to relative merits of the TSP versus NIPP but has been made to provide clearer guidance to the timing of funding requirements (given the assumption above on the one-off nature of NIPP costs to TSP).

We have assumed that the TSP will be responsible for the maintenance of all new assets from their commission date, irrespective of ownership. This is in line with current NIPP practice to hand over new assets to the TSP from an operational and maintenance perspective, although we have not seen evidence that this arrangement has been formalised in any way.

2 EXISTING ASSETS

We have derived our list of TCN and NIPP assets from the following sources:

- TCN Transmission line assets list (Performance Monitoring and Evaluation Department);
- TCN Transformers assets list (Performance Monitoring and Evaluation Department);
- TCN maps of existing and future planned projects; and
- NIPP Projects data list.

2.1 Treatment of TCN assets

The data list and maps from TCN were not themselves fully consistent although, to a certain extent, this was due to them having been compiled at different times. In particular, plans had changed in Lagos due to congestion problems. We reconciled them to the extent possible using what we believe to be the latest data. Where it was not clear, we checked with TCN.

Provided in Annex 1: is the complete list of TCN assets used for both loadflow and costing purposes.

2.2 Treatment of NIPP assets

The asset list and maps provided were largely consistent regarding NIPP330kV circuits (baring the Markudi – New Apo circuit) and were taken as is. For NIPP substations on the other hand, there have been a number of changes in the Lagos area and other minor changes for consistency. In addition, at some generation substations, feeders have not been connected via transformers to existing lower voltages within the substation (in these cases we added transformers as part of our expansion plan).

Provided in Annex 2: is the complete list of NIPP assets used for both loadflow and costing purposes.

2.3 Distinguishing between TCN and NIPP assets

NIPP assets cover new 330kV and 132kV lines, new substations either fed by NIPP lines or cut into existing TCN lines, new substations for NIPP power stations and the expansion of existing TCN substations. They obviously interact heavily with the existing TCN system and TCN developments of that system. Hence for our modelling purposes we have had the problem of distinguishing exactly which are NIPP assets and which are TCN.

We have been provided with data lists from NIPP and various maps of existing and future planned systems from TCN. These are in general consistent with each other however at a detailed level there have been many inconsistencies. A typical problem is whether a circuit exists or is planned/being constructed.

Where we have identified inconsistencies we have investigated with engineers at TCN and NIPP to find the actual situation. A couple of examples are:

- Makurdi – Apo New 330kV double circuit: The TCN diagrams show this as being constructed by NIPP; however this is not the case. NIPP inform us that it was originally in their plans but did not get funded. We believe constructing the circuit is beneficial so have included it in our future circuits.
- Substations being labelled as multi voltage (330/132/33kV) when one voltage level is not connected to the others. This happens for example when a NIPP power station is put in place where a 132/33kV substation already exists. In general we have left these with the same name and included 330/132kV transformers in the new asset list.

3 LOADFLOW STUDY

The purpose of this section is to determine loads in 2026 and demonstrate that the network in TCN's 10,000MW (10GW) plan, as extended by us is essentially feasible.

This is not a fully derived planning loadflow as would be expected from a System Operator proposing a detailed new network design. However it is sufficient to say that the added circuits and transformers are within a close range to that which will allow the network to deliver the proposed demand.

3.1 Approach

The costing timetable is from 2014 to 2023 however given that it can take up to three years from initial spend to circuit or substation commissioning we have to consider the network out to 2026.

- We start by prediction the peak annual distribution network power offtake for 2026. This is based on NERC's Multi-Year Tariff Order (MYTO).
- We then populate the substations on the network with these loads in accordance with the distribution of load assumed by TCN's 10GW plan.
- Generation stations were added based on the Ministry's list that was populated in collaboration with developers at meetings held in early 2012. New projects, in particular the hydros at Mambilla and Zungeru, were also added. Optimally in a full planning study multiple load flows would be done with different patterns of generation, however we have chosen a generation pattern that is relatively stressful to the network, but not excessively so.
- The next stage was to add circuits and substations in line with the existing TCN 10GW plan. In places alterations were required given revised investment decisions. This was particularly true in the Lagos area given congestion issues.
- An initial loadflow was run at the peak power offtake expected in 2026 (13.7GW). The purpose of this initial run was to determine circuit and transformer loading. 330kV circuits were then added appropriately to reduce loading, and substation configurations were altered as necessary.
- 330/132kV transformers were added as necessary to reduce loading to N-1 levels. Capacitors and reactors were also added as necessary to give a reasonable voltage profile.
- The loadflow was rerun multiple times until it was deemed acceptable.
- Requirements for generic 132kV lines and 132/33kV substations were estimated.

The final load flow was N-1 secure providing there were no outages at 330kV and at 330/132kV. This was not the case at 132/33kV.

3.2 Demand prediction

3.2.1 MYTO Load

Accurate load forecasting is highly problematic in Nigeria given the existence of unmet demand. NERC's current tariff model (MYTO2) is the reference point for all tariff and revenue analysis. Hence in assessing transmission costs (particularly needed investment) the main case must be closely related to the load predictions in the MYTO2 model.

MYTO2 uses annual generation sent out (energy) as its base figure. For the purpose of assessing transmission requirements what is required is annual peak power delivered to distribution networks. Two factors must be considered to make the conversion from one to the other:

- The relationship between annual energy and annual peak load – the annual load factor; and
- The percentage reduction between generation sent out and delivery to distribution networks, this consists of:
  - Exports to neighbouring countries: these are modelled in MYTO as 5% - which we use;
  - Transmission losses: these are modelled in MYTO as 8.05 % - which we use.

Annual load factor

As the Nigeria Electricity Supply Industry (NESI) does not currently meet customer load, the relationship between peak annual generation and annual generated energy is essentially the average annual load factor (79.3% for 2012). The average annual load factor for Sub-Saharan Africa is around 70%, this figure is currently used in both Zambia and Kenya as part of their long-term planning.

In the model we have linearly reduced the load factor from 79.3% to 70% in 2018 – representing improvement in delivery to customers. The value this gives for 2013 is 77.7%.

Current MYTO shortfall

For 2013 applying the load factor of 77.7% to the annual predicted energy of 41,884GWh gives an annual peak generation sent out of 6152MW. This will not be achieved this year. We have not yet surpassed the 2012 figure of 4424MW.

The primary reason is transmission constraints, in particular voltage stability and dynamic stability (small signal stability). If the NIPP circuit from Ajaokuta to Gwagwalada is energised and connected to feed Abuja and support the north; and the TCN Niger crossing circuit from Onitsha to Benin is commissioned; we may break 5000MW by the year end. We have therefore reduced the annual peak generation for 2013 from 6152MW to 5200MW.

In the following years we have increased the growth rate to return to values equivalent to MYTO2 by 2018.

Expected national loads 2013 to 2026

Year	Generation Sent Out Peak MW	Peak MW after Exports	Peak Delivery to Discos (MW)
2013	5,200	4,940	4,542
2014	6,500	6,175	5,678
2015	7,800	7,410	6,813
2016	8,736	8,299	7,631
2017	9,649	9,167	8,429
2018	10,614	10,083	9,272
2019	11,145	10,587	9,735
2020	11,702	11,117	10,222
2021	12,287	11,673	10,733

2022	12,901	12,256	11,270
2023	13,546	12,869	11,833
2024	14,224	13,513	12,425
2025	14,935	14,188	13,046
2026	15,682	14,898	13,698

3.2.2 Load Distribution

The national load Forecast is not sufficient to decide where to build transmission. It is necessary to have the distribution of load across the country, normally estimated by taking the distribution on the current system by substation and to scale this in some manner to reach the national demand for the future year.

Expected load distribution from TCN's 10GW plan

TCN's 10GW plan includes detailed 2012 loads and projected (10GW) loads by substation. The 10GW case loads were estimated by splitting the system regionally and growing demand in each region in accordance with World Bank's regional GDP growth projections. TCN then allocated the new demand pro-rata to existing and expected new substations based on existing measured demand.

We verified the actual loads in the plan against the TCN transformer loading report, giving us confidence that the projected 10GW case was built on a sound basis. We then scaled the 10GW case loads to the discos loads expected by 2026 (13.7GW). Summing individual substation loads by region gives the following projected loads for 2026.

Region	NIAF 2026 Projection (MW)	Percentage of 2026 total
Benin	1293	9.4%
Bauchi	1034	7.5%
Enugu	1071	7.8%
Kaduna	2206	16%
Lagos	3860	28.2%
Oshogbo	1483	10.8%
Port Harcourt	1354	9.9%
Shiroro	1400	10.2%
Total	13700	100%

A complete breakdown of measured and projected load by substation is shown in Annex 6:.

Verification against MYTO disco load allocations and TCN disco stress tests

To verify the load distribution it was compared to:

- The demand allocation predictions contained within MYTO2 for 2026 (that our national total load forecast is based on) by disco;
- A study conducted in October 2012 by TCN to determine the maximum potential off-take of each disco feeder (by allowing each feeder to take its full potential load). Feeders were then summed by disco.

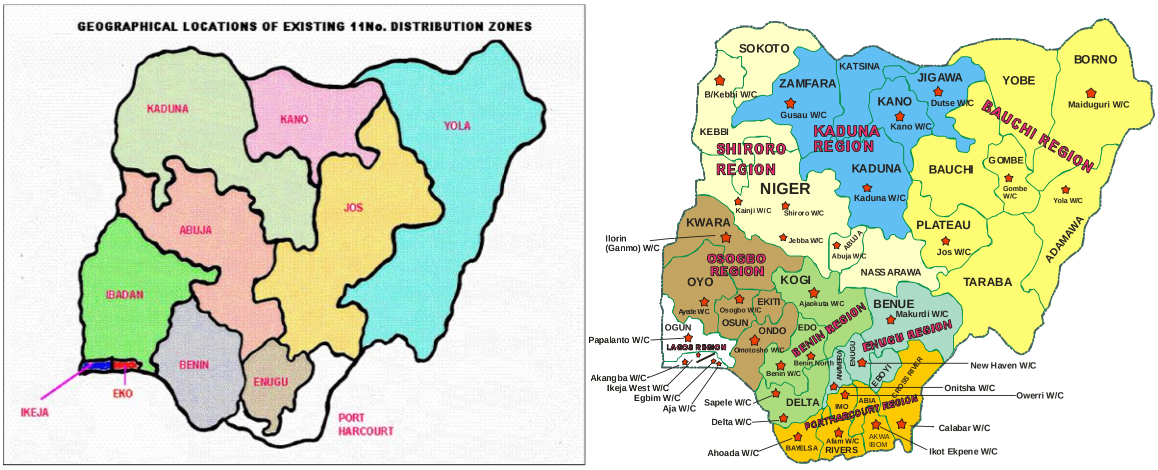
The percentage dispersal of load, by disco, for each of these sources is given in the table below.

Disco	% of total allocated in MYTO2 (2026)	Actual peak offtake as % of total (Oct 2012)
Abuja	12%	7.8%
Benin	9%	9.8%

Enugu	9%	10.0%
Eko	11%	12.2%
Ibadan	13%	11.8%
Ikeja	15%	11.8%
Jos	6%	6.0%
Kaduna	8%	5.5%
Kano	6%	6.4%
Port Harcourt	6%	13.1%
Yola	4%	3.5%

The peak off-take numbers are the highest potential load each disco could off-take (in October 2012) and as such are not directly comparable with our main case which is tariff based but they provide some reassurance to the MYTO numbers.

The comparison of the demand allocation predictions contained within MYTO2 to our TCN region based demands is not straight forward. The comparison involves comparing disco load with TCN regional load as they cover different areas of the country. However, there is some compatibility.



Source: TCN

In the table below, we have aggregated Disco and regions in such a manner that they are visually similar on the map above. These result look highly consistent, where one number is higher discrepancies can largely be explained by variations in geographical coverage. For example, the Enugu and Port Harcourt TCN regions include Makurdi whereas Makurdi is supplied by Jos Disco.

Disco	Percentage of load	TCN Region	Percentage of load
Ikeja and Eko	26.7%	Lagos	28.2%
Kano, Kaduna and Abuja	26.4%	Kaduna and Shiroro	26.3%
Jos and Yola	9%	Bauchi	7.5%
Enugu and Port Harcourt	15.4%	Enugu and Port Harcourt	17.7%
Ibadan and Benin	22.5%	Oshogbo and Benin	20.3%

3.2.3 Successor company Disco investment plans

All the Discos are in the process of privatization and as part of this process the new owners were required to submit investment plans, the primary element in these plans is the expected Disco load growth.

We were able to gain access to some of these Disco demand predictions. These predictions were in terms of annual energy, hence given that our annual peak capacity are based on the MYTO annual demands, we compared them with these MYTO annual demands.

We found that in most cases the new investors had used the exact MYTO numbers and some had numbers that were slightly higher.

Given that in early years, we have reduced the MYTO demands slightly to allow for under achievement in 2013, this means that if anything the early years requirements for transmission investment are understated i.e. this report is not overstating the transmission requirement when compared with the Disco investment plan.

Year	Benin	Enugu	Ibadan	Jos	Kano	Eko	Ikeja	Port Harcourt	Yola	Total	MYTO National Off take
2012	3187	926	3358	1476	1598	2337	3877	1381	897	19038	26830
2013	4495	1046	4373	2012	2301	3296	4643	1948	1159	25273	36587
2014	5612	1805	5172	2431	2933	4115	5572	2432	1347	31420	44201
2015	6442	2668	5682	2702	3367	4724	6703	2792	1461	36542	49128
2016	6834	3353	6144	2836	3572	5012	8079	2961	1566	40358	51568

Data for Abuja and Kaduna was not available. The growth over five years for the remaining nine discos was 20.66% per annum whereas the MYTO growth over the same period was 17.74%.

3.3 Generation forecast

In performing a full long term master plan it would be normal to do multiple scenarios with many different generation patterns. This often includes varying assumptions on those generation stations that will be commissioned first and should, at very least, consider different availability patterns (for example seasonal variability for hydro generation). Given our primary purpose was to estimate transmission costing requirements and not to perform a full master-plan, it was decided to use a single generation scenario.

Our data was obtained from the Ministry's list that was populated in collaboration with developers at meetings held in early 2012. In choosing how to load the generation we took the principle of creating a reasonable stressed system. We operated the existing hydro at relatively high generation, and between gas in the south east and south west we chose to favour the south east heavily given the greater gas constraints in the south west. In choosing which generation to prioritize, we largely opted for NIPP for two reasons:

- NIPP projects are well forward in terms of finance and construction;
- NIPP projects are largely are in the south east delta, hence they have good gas supply and they stress the transmission system.

Given current government plans to develop Hydro generation, we included Mambilla and Zungeru. Given that these power stations required new connections to the grid; we chose to model them at reasonably fully loaded.

The total generation capacity that has been reported from the Ministry's list was 24.5GW. We have chosen to reduce this to 20781MW allowing for 75% availability factor as discussed below. The total list is given in Annex 3: with those power stations we have chosen to leave out set at zero capacity.

3.3.1 Successor company investment plans

The new generator owners were required as part of their bids to guarantee that they would expand the power stations in a standard manner i.e. for each power station the tender describes this expansion. This requirement varies significantly from power station to power station for example Shiroro Hydro concession has no expansion requirement whereas Afam IV and V expands from a current capacity of approximately 70MW to 1120MW (as Afam is still in the process of sale we have not received the business plan for it). The table below shows the generation capacity in the business plan that we have access to and the final column shows the capacity utilized to back our load flow.

Power Station	2012	2013	2014	2015	2016	2017	Capacity in 2026 Load flow
Geregu	414	414	414	414	414	414	414
Jebba	540	540	540	540	540	540	540
Kainji	440	426	239	417	503	760	750
Sapele	320	480	980	980	980	980	980
Shiroro	360	480	600	600	600	600	600
Ughelli	382	382	666	666	850	1074	1074

3.3.2 Generation profile by 2026

We expect that by 2026 the generation profile in terms of the following categories will be that in the table below. This includes allowances for generation availability (hydro load factor, maintenance and breakdown but not lack of gas) of 75% overall. This is built up from the following assumptions:

- the Hydros operates around 50%;
- Successor Company (SC) Gencos around 60-65%;
- NIPP 80-85%;
- IPPs at 90%.

Gen by 2026 is classified as Successor Company thermal, Hydro concession, NIPP, IOC + IPP, and New Hydro. Station counts and capacities by type is given below.

Class	Count	Capacity (MW)
SC Thermal	7	5518
Hydro concession	3	1900
NIPP	12	5188
IOC + IPP	21	4475
New Hydro	2	3700

For detailed breakdown see Annex 3:.

3.4 New 330kV circuits

We have based our new 330kV circuits on TCN's 10GW plan. We have altered the set of 10GW circuits where changes have been made in the interim and propose additional circuits to meet 13.7GW. Below we discuss the set of new circuits and changes to the existing configuration. When considering the investment cost of these circuits, it has been necessary to allocate their commissioning to particular years.

3.4.1 Need for 760kV circuits

We considered including 760kV circuits at the load of 13.7GW delivered to discos under our 2026 case. We felt that the loadflow was sufficiently robust, and represented greater cost-efficiency, without 760kV circuits. In all likelihood, before the Nigerian transmission system achieves 20GW delivered to discos, at least one 760kV circuit from the South East Delta Region to Lagos would probably be required and be cost effective. This would not be incompatible with the network proposed in this study.

3.4.2 Known changes to 10GW plan

On the 10GW plan there is a new north Lagos substation at Erunkan cut into the double circuit from Egbin to Ikeja West. The substation has now been moved slightly out and is being commissioned at Oke-Aro. It was intended to be the main north Lagos hub with an additional double circuit infeed from Omotoso – this is no longer the case due to congestion. Instead we include Ogijo substation cut into the northern Egbin to Ikeja West double circuit further out to the northwest of Lagos, to function as the main north Lagos hub. The double circuit from Omotoso will now feed in here. When 760kV circuits are built this would, in all likelihood, be the Lagos terminus.

In total we have made four additions from the network specified in the 10GW plan. They are:

- IKEJAW – OLORUNSOGO – This is a new double circuit in the 10GW plan we have chosen to upgrade the existing single circuit to double circuit given the congestion in the area.
- OMOTOSO – OGIJO – See explanation above.
- OLORUNSOGO - OGIJO – Support into the new north Lagos hub.
- LOKOJA – OBAJANA – Lokaja shown as a cut in to one of the Ajaokuta – Gwagwalada circuits whereas it is a full nodal substation.

The following substations have their connections adjusted as follows:

- AKURE – In the 10GW plan Akure is shown as cutting into one of the two new Benin North - Osogbo circuits. We have changed this to both circuits.
- SOKOTO – In the 10GW plan Sokoto is shown as cutting into one of the two new Birnin Kebbi – Gusau circuits We have changed this to both circuits.
- TMAFARA – In the 10GW plan Talata Mafara is shown as bypassed by the two new Birnin Kebbi – Gusau circuits. We have changed this to cutting into both circuits.

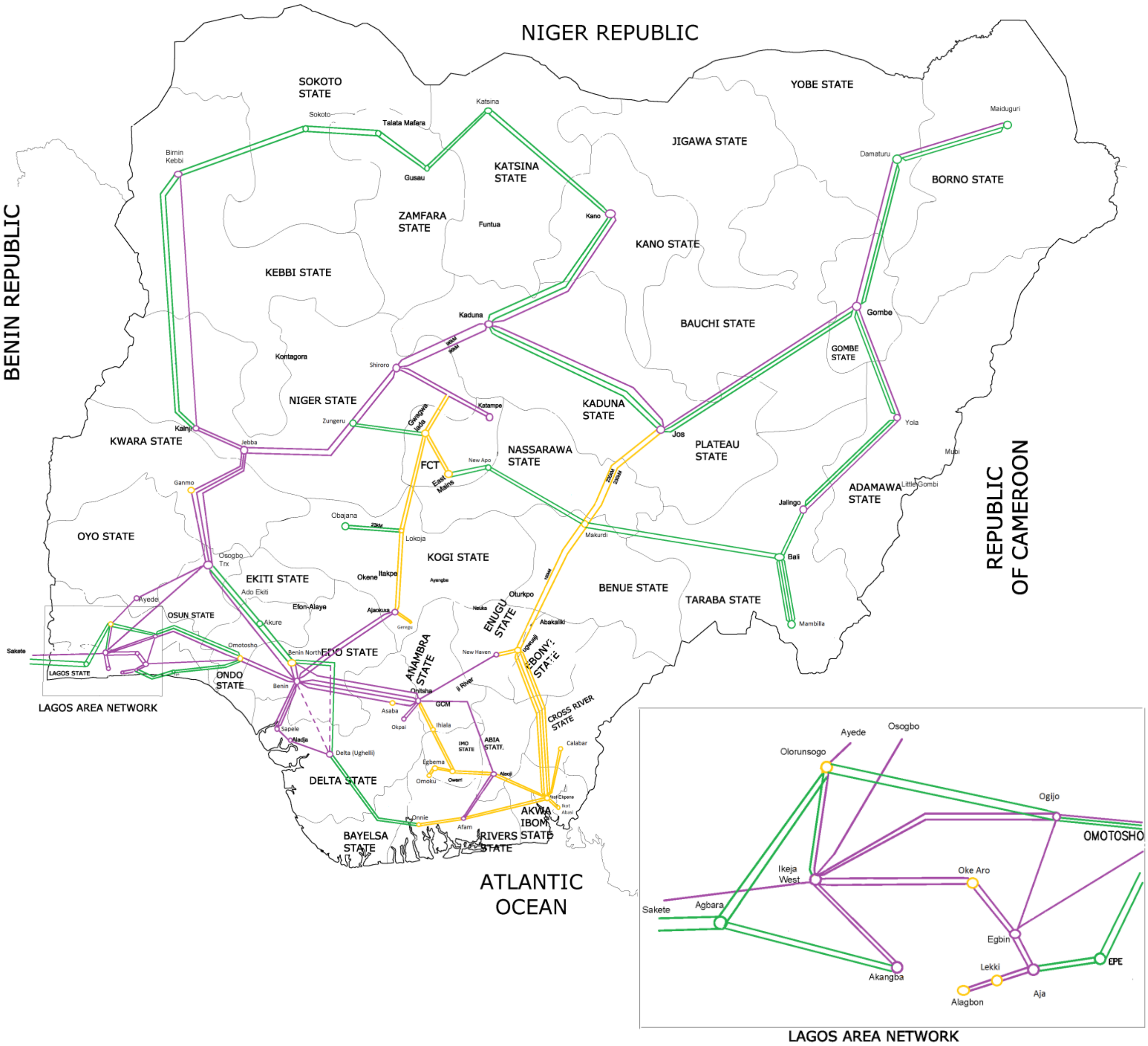
3.4.3 Extra circuits

The following new double circuits have been added to achieve 13.7GW:

- BALI – MAMBILLA 1 and 2 (both double quad circuits) – These are required to export the generation of 3000MW from Mambilla with N-1 security.
- BALI – MAKURDI (double circuit quad) – This is required to export the generation that comes in from Mambilla so that it can flow to Jos and Abuja.
- DELTA IV - BENIN NORTH – The existing circuit from Delta to Benin overloads once the Onne -Delta double circuit is built, hence another circuit from Delta is needed and given that Benin substation has no space for further line bays, this circuit and the existing Delta- Benin circuit are moved to Benin North.
- AKANGBA – AGBARA – The current radial double circuit from Ikeja West to Akangba is overloaded, therefore another circuit to Akangba is required ideally this would be a cross harbour cable from Alagbon, however there are potential engineering and cost problems, hence upgrading the existing 132kV right of way to 330kV from Ikeja West to Agbara appears appropriate.
- APONEW – EASTMAIN – This is a sensible connection given that a new 330kV substation is in the TCN/NIPP plan at EastMain and that Apo is the Main Abuja load centre.
- APONEW – MAKURDI – This improves the flows from the South-East Delta and Mambilla to Abuja and the central north of the country.
- ZUNGERU – GWAGWALADA – The new hydro power station at Zungeru is cut into the Shiroro-Jebba double circuit. The power station is 700MW capacity so the circuits will overload under certain conditions without another outlet. This also increases delivery to Abuja.

3.4.4 Expected 13.7GW network in 2026

The 330kV network we consider required to meet 13.7GW in 2026 is given in the maps below. The purple circuits are existing TCN circuits (which includes those under construction and expected to be completed in 2013); yellow circuits are NIPP circuits; and green circuits are new circuits required to meet the 13.7GW demand.



There are no circuits on the 330kV network which, if tripped would cause another circuits to overload. However, there are parts of the proposed network where, if one of the circuits is out for maintenance and another circuit trips, then the remaining circuits will be overloaded. Hence we do not have full N-1 security.

Provided in Annex 4: is the complete list of 330kV lines in the 13.7GW model and used for the costing exercise.

3.5 330/132kV transformation

In carrying out the load flow studies mentioned above, we have assumed the tap changers on the network transformers are set (either manually or automatically) so as to maintain the voltage on their LV side at 132kV (±2%).

The transformer loading from the initial load flow was recorded and analysed and where the load was too high to provide N-1 security (i.e. where one transformer trips the remaining transformer do not overload) transformers were added appropriately. Where more than one transformer was added the timing of the event was staggered.

Note at Ikeja West and Akangba, because of very high loading and the fact that these substation are in Lagos where they have very little space, TCN policy is that the 150MVA transformers are to be replaced by 300MVA transformers.

In costing, we have assumed the old 150MVA transformer have no residue value.

Provided in Annex 4: is the complete list of 330/132kV transformation additions in the 13.7GW model, split between new substations and the expansion of existing substations, used for the costing exercise.

3.6 Generic 132kV circuits and below

We were not able to take the same detailed approach to 132kV voltage level and below as we did for the 330kV voltage level. This is because firstly, current TCN planning does not reach this level, secondly, to plan accurately as this level coordination with Disco planning is required. We therefore took a generic approach, as follows:

- Assessed the need for additional 132/33kV transformation capacity in each TCN region.
- Assessed the number of additional standardised 132/33kV substations required and when they will be needed.
- Assumed that each new standardised 132/33 substation will be fed by a new radial standardised 132kV line, the length of which would vary by TCN region.
- Included substation expansion works to existing 330/132kV substations where the new radial standardised 132kV line connects to the existing network.

3.6.1 132/33kV transformation

132/33kV transformation by region was estimated as follows:

1. Calculated the demand in MW for each region for each year;
2. Calculated the equivalent MVA using the standard TCN power factor assumption of 0.8 to give us the amount of transformer capacity to exactly meet the demand in that region;
3. Allowed for a level of security at this transformation level plus an allowance for diversity of loading across the region by increasing the MVA by 65%;
4. For each region, we summed up the existing transformation capability;
5. We subtracted this from the required transformation capacity for each year to give the new capacity required by that year;
6. We then assumed that this new transformation capacity would be supplied by TCN standard transformation stations containing two 60MVA 132/33kV transformers; and
7. We divided the required transformation capacity by 120MVA and rounded up to give the number of new standard substations required by each region by year. Results are given below.

Timing of new 132/33kV substations required by year and region.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Bauchi	0	0	1	2	3	3	3	4	4	5	6	6	7
Benin	0	0	2	3	4	5	6	7	8	8	9	10	11
Enugu	1	3	4	5	7	8	9	10	10	11	13	14	15
Kaduna	6	9	12	14	17	18	20	22	23	25	27	29	31
Lagos	1	6	11	15	19	21	24	26	29	32	35	38	41
Osogbo	0	0	1	2	3	4	5	5	6	7	8	9	10

Port Harcourt	0	0	0	0	1	2	3	4	5	6	7	8	9
Shiroro	0	0	0	0	1	2	2	3	4	5	5	6	7

The number of required substations in the Kaduna region appears to be somewhat disproportionate to other regions. We have checked input data and calculations and the result remains. While this may be on the high side we have confidence that total numbers are reasonable.

3.6.2 132kV lines

We assumed that each standard substation was fed by a 132kV double circuit of standard design. For simplicity we assumed that these lines would be radial coming from an existing 330/132kV substation, however in practice it is likely that some of these will be put in on a ring basis.

In order to decide the length of the transmission line we calculated for each region the current average length of 132kV lines and made the assumption that on average that these new transmission lines will be the same length. These averages are:

TCN Region	Total KM	No.of Lines	Av. KM per line
Bauchi	1,575	19	82.89
Shiroro	1,426	19	75.05
Kaduna	1,148	19	60.44
Benin	482	9	53.53
Port Harcourt	657	19	34.58
Enugu	732	24	30.49
Osogbo	513	18	28.51
Lagos	611	32	19.10

Given the assumption of radial 132kV lines, the number and timing of new 132kV lines will be equal to the number and timing of 132/33kV substations above.

3.6.3 330/132 substation expansions

For every new 132/33kV substation and 132kV line we have also included the expansion of the 330/132kV substation where the line connects into the existing network. This comprises two additional circuits connected by three transformer bays.

Provided in Annex 4: is the complete list of 132kV lines and 132/33kV transformation additions in the 13.7GW model, split between new substations and the expansion of existing substations, used for the costing exercise.

3.7 Substation reactors and capacitors

Currently voltage collapse is a major cause of system shutdowns. This is principally because there is little voltage compensation (shunt reactors and capacitors) on the system. In our view one of the weaknesses of the NIPP transmission development programme is a lack of reactors and capacitors.

At present the transmission system is equipped with a small number of shunt reactors connected to the 330kV busbars or the tertiary side of the 330/132 kV transformer. This is to cope with high voltage at the remote substation during off-peak load conditions. Despite a load power factor around 0.8 at most distribution interface points, there are very few capacitors on the system.

We have therefore:

- Included a 75MVA reactor at 330kV and a 40MVA capacitor at 132kV in each new 330/132kV substation.
- Included a 40MVA capacitor at 132kV and a 20MVA capacitor at 33kV in each new 132/33kV substation.
- Allowed for significant numbers of reactors and capacitors around the network as part of a refurbishment programme based on load flow analysis of the system, reactors and capacitors have been placed at existing substations. The list of recommended reactors and capacitors as part of this refurbishment programme is given in Annex 5:.

There has been discussion about the use of SVCs (Static Var Compensators), the primary purpose of which is to give semi-active control of voltage control during varying voltage conditions, in order to solve the voltage problems. Given that the problems are either high voltages in particular areas or low voltages in others, we do not consider this appropriate. Using SVCs for this purpose massively increases cost (an SVC would cost three times as much as a capacitor or a reactor).

4 TSP CAPEX AND MAINTENANCE MODEL

4.1 Types of project

The importance of, and distinction between, new assets, substation expansion, refurbishment and maintenance is intellectually clear. However to ensure comprehensive coverage and aid modelling the following detailed distinctions are required.

Lines

- New line construction involves the building from new on a greenfield site of a new line.
- A five year line refurbishment is included for all existing lines given chronically poor maintenance over a long period. This involves:
    - Either, the overhaul of existing components keeping specifications constant;
    - Or, the replacement of existing components keeping specifications constant where refurbishment is not considered economical.

  In the very limited number of cases (three), existing 66kV line refurbishment costs are estimated on the basis of 132kV costs.
- Annual line maintenance costs are estimated on the basis of maintaining suitably refurbished lines. These are included throughout the entire period for existing assets and from the year after commissioning for new assets. In the very limited number of cases (three) existing 66kV line maintenance, costs are estimated on the basis of 132kV costs.

Substations

- New substation construction involves the building from new on a greenfield site of a new substation.
- Substation expansion involves the addition of new circuits and/or new transformers at existing voltages at existing substations. (Transformers currently housed in the relevant substation remain in place.)
- Substation refurbishment is included for all existing substations given chronically poor maintenance over a long period. This involves:
    - either the overhaul of existing components keeping specifications constant;
    - or the replacement of existing components keeping specifications constant where refurbishment is not considered economical.

  The exception to this is where components (particularly transformers) do not follow current TCN standards for voltage (e.g. 132/11kV) or capacity (e.g. 40MVA at 132/33kV). In these cases refurbishment costs are estimated on the basis of standardisation upward to the nearest standard size.

In addition we have included provision for the installation of additional reactors and capacitors to support voltage around the network. This has been included under refurbishment.

- Yearly substation maintenance costs are estimated on the basis of maintaining suitably refurbished substations. These are included throughout the entire period for existing assets and from the year after commissioning for new assets.

There are a number of important implications that should be highlighted as a result:

- The expansion of an existing transmission line is not expected under any circumstance given the lack of redundancy in the system currently. It is currently not possible to temporarily decommission a line without the whole grid going down and this situation is not expected to change until late into the costing period. Therefore any increase in transmission capacity along an existing corridor is costed as a new line (see next bullet).
- New lines that are constructed along existing corridors are priced as new including corridor clearance and wayleaves. This is only likely to occur when higher line voltages are required. In this situation the corridor is likely to have to be wider than currently exists so some additional corridor clearance and wayleave costs can be expected in any case.
- The addition of new circuits at different voltages to existing substations is excluded from substation expansion. This is therefore been costed as a new substation consisting of the additional circuits added to the substation.
- The replacement of existing transformers with higher capacity transformers is excluded from substation expansion due to the standardisation aspect of refurbishment which has a similar effect.
- Any on-going TCN transmission project expected to be completed by end-2013 is treated as an existing asset at the start of our model period (2014-2023).
- Any on-going TCN transmission project not expected to be completed by end-2013 is costed as a completely new asset however close to reaching completion it is considered to be. This assumption is made given significant uncertainties as to project progress and supplier competencies in each individual case. There is also a risk that that future government allocations to complete such projects will not be forthcoming, as has been the case in the past.
- Given the chronic lack of reactors and capacitors around the network (currently 29), and the fact that substantially increasing this number is not adequately captured in any of the categories above, a separate analysis of voltage support costs has been included.

4.2 Cost drivers

For both lines and substations we have identified the following cost drivers (this has been partially determined by the structure of unit cost data obtained see section 4.4.1):

- For lines:
  - route survey and corridor clearance;
  - wayleaves;

    towers;
  - insulators; and
  - Wires
- For substations:
  - circuit breaker bays (CBBs);
  - transformers;
  - reactors and capacitors;
  - substation general.

These cost drivers were identified as a compromise between the need to keep the costing model as simple and understandable as possible, while also including sufficient detail to ensure that modelled costs vary as they do in reality.

Design costs were not included as a cost driver given the structure of our unit cost data (see section 4.4.1).

Lines

To demonstrate the comprehensiveness of our line cost drivers it is simply necessary to consider the basic tasks towards commissioning a transmission line.

1) A preliminary survey is conducted. These costs are included in our first cost driver.
2) This is followed by tower spotting (a more detailed survey where the position of the towers is decided). These costs are included in our first cost driver.
3) The right of way is procured. Related wayleave costs are our second cost driver. This is likely to result in some design changes which are again excluded given the structure of our unit cost data.
4) A final survey is conducted. These costs are included in our first cost driver.
5) A corridor (generally 50m wide) is cleared including bush clearing and the cutting of dangerous trees. The access road to the route and the one along the route is also built. These costs are included in our first cost driver.
6) The tower foundations are dug and filled and towers are constructed on the foundations. These costs are included in our third cost driver.
7) The insulator strings are hung from the towers. These costs are included in our fourth cost driver.
8) The wires are strung through the insulator strings and then tensioned. These costs are included in our fifth cost driver.

At this stage the line is complete and just needs to be connected up to the substations and commissioned.

Substations

Costs were allocated to the four cost drivers as follows:

- Circuit Breaker Bays (CBBs) – Items included here were the CBs themselves, appropriate numbers of isolators and earth switches, sections of busbar, control/protection panels, CTs, VTs, plinths and other minor items. The choice of allocating by CB bay rather than allocating some of these items to the substation generally allows more efficient and accurate costing of different sized substations.
- Transformers – Included here were the transformers themselves, protection panels, connections, supports, oil separators and earthing reactors.
- Reactors and capacitors – Items included here were the reactors and capacitors themselves, protection panels, connections, supports, and oil separators.
- Substation general – The remaining items were allocated to substation general costs. This included: the substation service transformer and automation, the busbar protection systems, the data analysis station, the remote digital fault recorder and locator, the diesel generator set and batteries with charger, etc.

Land right costs were considered very small and were not included in our costings. It should be noted that there remains some relation between these categories as defined. For example, when including a reactor, for example, the cost of a circuit breaker bay, as well as the cost of the reactor, should also be included.

4.3 Mapping types of project and cost drivers

The following tables show how cost drivers have been combined for different types of project.

Lines

	Route survey and corridor clearance	**Towers**	**Insulators**	**Wires**	**Wayleaves**
New lines	Included	Included	Included	Included	Included
NIPP lines	Included	Included	Included	Included	Included
Line Refurbishment		Included	Included	Included	

	Route survey and corridor clearance	Towers	Insulators	Wires	Wayleaves
Line Maintenance	Included	Included	Included	Included	

Substations

	Substation general	Transformers	Circuit Breaker Bays	Reactors and Capacitors
New substations	Included	Included	Included	Included
NIPP substations	Included	Included	Included	Included
Substation Expansion		Included	Included	Included but calculated independently
Substation Refurbishment	Included	Included	Included	Included
Maintenance	Included	Included	Included	Included

4.4 Modelling new build requirements

4.4.1 Available data

Over the last decade NIPP has by far been the largest constructor of transmission assets. We have been able to obtain actual bill-of-quantity (BoQ) costs from NIPP that we consider to be by far the best source of Nigeria-specific new-build unit-cost information.

The structure of NIPP BoQ costs has informed our costing structure. On a NIPP BoQ for each line item costs are given for:

- "Cost and Freight (C+F)" – The cost of purchasing an item at the port of entry in Nigeria. Shipping and customs charges are therefore included here. Units are US Dollars (USD);
- "Erection (E)" – The cost of erection in foreign currency (USD);
- "Local Transportation and Erection (LTE)" – The cost of transportation to site and erection in Nigerian Naira (NGN).

NIPP contracts out all construction; contracts are generally 'Engineering, Procurement and Construction (EPC)'; and the cost information we obtained was all on this basis. We have therefore assumed a similar contractual structure.

The information we obtained from NIPP was averaged over the following NIPP contracts. The list of projects implies a varied set of contractors and consultants.

LOT	PROJECT DESCRIPTION
Lot1A	330/132/33kV SS Makurdi
Lot2A	330kV DC T/L Mkd-Aliade
Lot2B	330kV DC T/L Aliade- Ugwuaji
Lot 3D	330kV DC T/L Ugwuaji- New Haven
Lot4A	330kV DC T/L Afam –Ikot -Ekpene
Lot4C	330kV SS Ikot-Ekpene
Lot5A	330/132/33kV SS Iokt-Abasi
Lot9A	330/132/33kV SS Ganmo

Lot17-1	330/132/33kV SS Onne
Lot17-2A	330kV DC T/L
Lot17-2B	132kV DC T/C
Lot19-2	330/132/33kV SS
Lot22-2	330kV DC T/L Ajakuta-Lokoja-Gwagwalada

It should be noted that engineering design costs are not stated explicitly (instead being built into unit costs) but surveying and corridor clearance are however included as separate line items. Our estimates follow this convention.

Where NIPP bill of quantity information is not available either another source has been used or costs have been estimated given scaling relative to known costs from NIPP. These cases are clearly documented below.

Following discussions with TSP staff towards the end of the study some costs have been revised away from the NIPP numbers. Where this has occurred is clearly documented below.

4.4.2 New line unit costs

Environmental and social impact assessments

At the request of TSP, Environmental Impact Assessment (EIA) and Social Impact Assessment (SIA) costs have been included, in line with the EIA Act 86 of 1992, the Federal Ministry of Environment (FMENV) Sectoral Guidelines for Infrastructures (Power Transmission lines) projects and World Bank/International Finance Corporation (IFC) guidelines.

In our view EIA and SIA costs will be in the region of NGN150m per line. This should however vary by length. Given 165 new lines are included in our model, with a total length of 10,270km, we have included an average cost per km of NGN2.4m.

Route survey

Survey and clearance costs were obtained from NIPP, for both high and low wind cases for both 132kV and 330kV lines. Given limited variation averages were used and simplified to two categories, route survey and corridor clearance per km. The category ‘survey costs’ includes:

1. preliminary route survey;
2. alignment route survey and profile (tower spotting); and
3. survey including staking.

The actual costs obtained by NIPP are given in table below. Given the relatively small variation between 330kV and 132kV costs the average was used.

Survey	Total (NGN)		Total (NGN)
330kV high wind total costs (per km)	*330,000*	*132kV high wind total costs per km*	*294,895*
Preliminary route survey per km	110,000	Preliminary route survey per km	73,750
Tower spotting per km	110,000	Tower spotting per km	98,350
Final survey per km	110,000	Final survey per km	122,795
330kV low wind total costs (per km)	*300,000*	*132kV low wind total costs per km*	*241,650*
Preliminary route survey per km	100,000	Preliminary route survey per km	64,500
Tower spotting per km	100,000	Tower spotting per km	65,800
Final survey per km	100,000	Final survey per km	111,350
330kV Average	**315,000**	**132kV Average**	**254,773**
Average (used in Model)	**284,886**		

Subsequently addition information was received from TCN on survey cost per km is given below. Given the relatively small variation between average survey cost we obtained from NIPP and from TCN, we have used NIPP costs in our model to ensure consistency across cost types.

TCN Regions	Survey costs per km (NGN)
Benin	270,000
Bauchi	291,000
Enugu	291,000
Kaduna	270,000
Lagos	291,000
Oshogbo	291,000
Port Harcourt	291,000
Shiroro	270,000
Average	**283,125**

Corridor clearance

The category 'corridor clearance costs' includes:

- 50m wide right of way including construction access;
- additional route bush clearing per 5m width;
- cutting of dangerous trees (20 assumed per kilometre);
- access road along the route and access road to the route.

The actual costs obtained from NIPP are given in the table below. This is one of the few times that NIPP costs did make intuitive sense (particularly regarding the large variation between high and low wind scenarios for 132kV highlighted red). NIPP subsequently confirmed these costs to us. We therefore decided to take the average numbers over high and low wind scenarios for both 330kV and 132kV cases.

330kV high and low wind cases	Total (NGN)	132kV high and low wind cases	Total (NGN)
Total 330kV high wind per km	*818,000*	*Total 132kV high wind per km*	*856,975*
50m wide right of way including construction access	295,000	50m wide right of way including construction access	280,725
additional route bush clearing per 5m width	110,000	additional route bush clearing per 5m width	46,750
cutting of dangerous trees (assuming 20 per km)	93,000	cutting of dangerous trees (assuming 20 per km)	249,500
access road along the route	195,000	access road along the route	155,000
access road to the route	125,000	access road to the route	125,000
Total 330kV low wind per km	*738,000*	*Total 132kV low wind per km*	*434,750*
50m wide right of way including construction access	275,000	50m wide right of way including construction access	269,750
additional route bush clearing per 5m width	100,000	additional route bush clearing per 5m width	31,500
cutting of dangerous trees (assuming 20 per km)	93,000	cutting of dangerous trees (assuming 20 per km)	70,000
access road along the route	165,000	access road along the route	25,000
access road to the route	105,000	access road to the route	38,500

330kV Average	**778,000**	**132kV Average**	**645,863**

Subsequently, corridor clearance costs were obtained from TCN by region given in the table below. We have used NIPP corridor clearance cost in our model because of relatively small variation between NIPP and TCN average corridor clearance costs and to ensure consistency across cost types.

TCN Regions	330kV line clearance costs (NGN)	132kV line clearance costs (NGN)
Benin	700,000	500,000
Bauchi	750,000	600,000
Enugu	750,000	600,000
Kaduna	700,000	500,000
Lagos	800,000	650,000
Oshogbo	750,000	600,000
Port Harcourt	800,000	650,000
Shiroro	700,000	600,000
Average	**743,750**	**587,500**

Towers

Tower costs were obtained from NIPP for 330kV double circuit, double conductor; and for 132kV double circuit single conductor. In both cases high and low wind zones were also distinguished. In each of the four cases, costs were provided for five tower types:

- "AAH" type - 0 to 2° suspension;
- "BBH" type - 2 to 10° strain;
- "CCH" type - 10 to 30° strain;
- "DDH" type - 30 to 60° strain;
- "EEH" type - 60 to 90° strain.

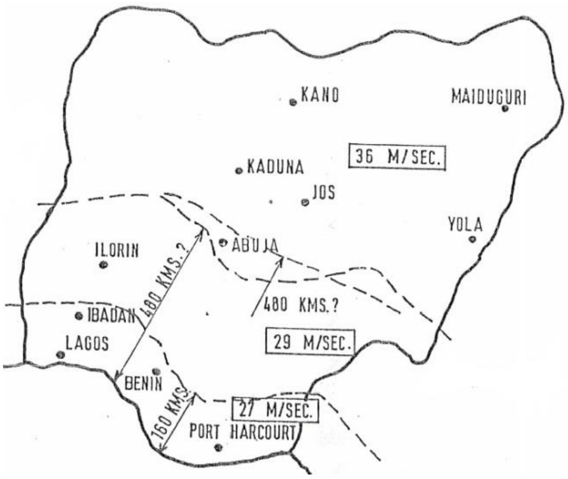
For each of these tower types, costs were provided for seven foundation types: R, 1, 2, 3, 4, 5 and S (i.e. from rock to swamp with increasing cost). For each tower type an average of the foundation costs was used.

For each voltage and wind zone case, tower types were simplified to “suspension” and “tension”. Suspension cost is taken as the average of types AAH and BBH above and Tension is the average of types CCH, DDH and EEH.

Lines were categorised by TCN region and regions were designated wind zone A or wind zone B as follows:

- Wind zone A (low wind): Benin, Enugu, Lagos, Osogbo and Port Harcourt regions
- Wind zone B (high wind): Bauchi, Kaduna and Shiroro regions.

This is demonstrated in the maps below. While not exact, the mapping is close to actuality.



Source: TCN Design and Construction Department

Source: TCN

The resulting costing, based on NIPP numbers is given below. The detailed breakdown of what is included in these numbers is given in Annex 7:.

Type	Voltage	Circuits	Conductors	Zone	C+F (USD)	Erection (USD)	LTE (NGN)
Susp	330kV	2	2	A	20,277	1,110	3,787,332
Susp	330kV	2	2	B	34,357	2,831	4,037,623
Ten	330kV	2	2	A	30,011	1,168	4,362,308
Ten	330kV	2	2	B	65,255	5,221	6,908,958
Susp	132kV	2	1	A	10,942	1,504	1,142,031
Susp	132kV	2	1	B	8,176	1,364	1,430,465
Ten	132kV	2	1	A	17,729	2,398	1,700,127
Ten	132kV	2	1	B	14,600	2,408	2,332,433

Costs for other voltage, circuit and conductor cases were derived from the two cases provided by NIPP by the application of ratios at 330kV and 132kV to allow for the reduced/increased steel costs required to support fewer/more conductors respectively. 330kV and 132kV were treated independently as voltage is by far the most significant factor affecting tower costs. The table below gives the ratio of conductors for each of these cases. In our engineering judgement 25% increase in cost for the circuit physical load increase is reasonable (which is equivalent to 20% decrease in cost for the circuit physical load decrease) given that voltage (and not conductors) is the most significant factor affecting tower cost.

Voltage	Change	Initial Conductors	New Conductors	Ratio	Cost Percentage	Factor
330kV	DC:2 conductor to 4 conductor	14	26	1.86	25%	1.25
330kV	Double Circuit to Single Circuit (2 con)	14	8	1/1.75	-20%	0.80
132kV	DC: 1 conductor to 2 conductor	7	13	1.86	25%	1.25
132kV	SC: 1 conductor to 2 conductor	4	7	1.75	25%	1.25
132kV	Double Circuit to Single Circuit (1 con)	7	4	1/1.75	-20%	0.80

Subsequently, TSP provided us with tonnage of steel per tower for 330kV double circuit, double conductor suspension towers by region given below. We allocated these to wind zones in accordance with the discussion on regions above.

Region	Wind zone	Tonnes per tower
Benin	B	18.00
Bauchi	A	15.00
Enugu	A	15.00

Kaduna	B	17.00
Lagos	A	15.00
Oshogbo	A	15.00
Port Harcourt	A	15.00
Shiroro	B	17.00
Average – Wind zone A		**15.00**
Average – Wind zone B		**17.33**

Also provided were the following conversion factors for computing tonnage for other voltage, circuit and conductor cases. Where comparable with the ratios applied to NIPP cost cases they are broadly inline.

- Suspension to Tension tower (any voltage, circuit or conductor case) – Add 40%
- 330kV, double circuit, double conductor to 330kV, single circuit, single conductor – Apply the ratio 16/18
- 330kV, double circuit, double conductor to 132kV, double circuit, double conductor – Apply the ratio 10/15
- 330kV, double circuit, double conductor to 132kV, single circuit, single conductor – Apply the ratio 8/15

TCN provided a cost and freight (C&F) price on the basis of $2000/tonne. World steel prices for "Structural Sections & Beams" have stood at about $800/tonne for the last few years with hot rolled plate at $700/tonne (Source: http://www.worldsteelprices.com). Given the primary tower type is a 330kV double circuit, double conductor suspension tower in low wind, we have chosen a C+F steel price of $1350/tonne so as its TCN cost estimate broadly aligns with the NIPP cost. Given the NIPP costs have come from multiple successful tenders and it brings steel prices to a more reasonable level we consider this reasonable.

The table below gives cost and freight (C&F) prices according to both NIPP and TCN numbers for a variety of tower types.

Voltage	Type	Circuits	Conductors	Zone	NIPP ($/tower)	TCN @ $1350/tonne	Difference
330	Sus	2	2	A	$20,277	$20,250	$27
330	Sus	2	2	B	$34,357	$23,400	$10,957
330	Ten	2	2	A	$30,011	$28,350	$1,661
330	Ten	2	2	B	$65,255	$32,760	$32,495
132	Sus	2	2	A	$13,677	$13,500	$177
132	Sus	2	2	B	$10,220	$15,600	-$5,380
132	Ten	2	2	A	$22,161	$18,900	$3,261
132	Ten	2	2	B	$18,250	$21,840	-$3,590

The NIPP C&F costs for high wind towers (highlighted red) appear somewhat erratic: very high for 330kV and below low wind for 132kV. We have therefore elected to use the TCN tonnages at $1350/tonne for C&F. These values are close to the NIPP values but more internally consistent. For voltage, circuit and conductor configurations where we required values not provided by TCN, the ratios utilized to calculate alternate configurations from the NIPP base data (discussed above) were utilized. The exception to this was the cases of 132kV double circuit, single conductor and 132kV single circuit, double conductor where the use of these ratios resulted in both configurations having C+F costs equal to the 132kV single circuit, single conductor configuration. In both these cases a revised ratio of 0.89 from the 132kV double circuit, double conductor case was used. This ratio was calculated as the geometric mid-point between 1 and 0.8 (which is the ratio from 132kV double circuit, double conductor to 132kV single circuit, single conductor implied by the information provided by TCN).

The resulting tower unit costs used as part of the model are:

	Suspension Towers	C+F (USD)	Erection (USD)	LTE (NGN)
Suspension - Wind zone A	330kV Double Circuit - four conductors per phase	25,313	1,387	4,734,165
	330kV Double Circuit - two conductors per phase	20,250	1,110	3,787,332
	330kV Single Circuit - two conductors per phase	16,200	888	3,029,865
	132kV Double Circuit - two conductors per phase	13,500	1,880	1,427,539
	132kV Double Circuit - one conductor per phase	12,075	1,504	1,142,031
	132kV Single Circuit - two conductors per phase	12,075	1,504	1,142,031
	132kV Single Circuit - one conductor per phase	10,800	1,203	913,625
Suspension - Wind zone B	330kV Double Circuit - four conductors per phase	29,250	3,539	5,047,028
	330kV Double Circuit - two conductors per phase	23,400	2,831	4,037,623
	330kV Single Circuit - two conductors per phase	29,250	2,265	3,230,098
	132kV Double Circuit - two conductors per phase	15,600	1,705	1,788,081
	132kV Double Circuit - one conductor per phase	13,953	1,364	1,430,465
	132kV Single Circuit - two conductors per phase	13,953	1,364	1,430,465
	132kV Single Circuit - one conductor per phase	12,738	1,091	1,144,372
Tension - Wind zone A	330kV Double Circuit - four conductors per phase	35,438	1,460	5,452,886
	330kV Double Circuit - two conductors per phase	28,350	1,168	4,362,308
	330kV Single Circuit - two conductors per phase	22,680	934	3,489,847
	132kV Double Circuit - two conductors per phase	18,900	2,997	2,125,159
	132kV Double Circuit - one conductor per phase	16,905	2,398	1,700,127
	132kV Single Circuit - two conductors per phase	16,905	2,398	1,700,127
	132kV Single Circuit - one conductor per phase	15,120	1,918	1,360,101
Tension - Wind zone B	330kV Double Circuit - four conductors per phase	40,950	6,526	8,636,198
	330kV Double Circuit - two conductors per phase	32,760	5,221	6,908,958
	330kV Single Circuit - two conductors per phase	26,208	4,177	5,527,167
	132kV Double Circuit - two conductors per phase	21,840	3,011	2,915,541
	132kV Double Circuit - one conductor per phase	19,534	2,408	2,332,433
	132kV Single Circuit - two conductors per phase	19,534	2,408	2,332,433
	132kV Single Circuit - one conductor per phase	17,834	1,927	1,865,946

Note: On initial inspection foreign erection costs for 132kV suspension towers appear problematic. (High wind should not be cheaper than low wind.) This is however corrected once the total local and foreign erection costs are considered. This correction also applies for foreign erection costs for 330kV tension towers compared with 132kV tension towers which, on initial inspection, appears problematic.

Insulators

Costs of insulator strings were obtained from NIPP for 330kV and 132kV for tension and suspension towers. For tension towers the strings were doubled up and were approximately twice the cost of single suspension strings. Hence an average cost for a single string for each voltage was calculated and tension towers treated as having twice as many insulator strings. No data was available on how insulator string costs vary by number of conductors. In our engineering view this would be comparatively small hence number of conductors was ignored as a factor affecting insulator costs. The resulting insulator string unit costs used as part of the model are:

	C+F USD)	E (USD)	LTE (NGN)
330kV insulator per unit	621	72	1,291
132kV insulator per unit	408	15	707

The detailed breakdown of what is included in these numbers is given in Annex 7:.

Wires

Wire costs were obtained from NIPP per conductor per km for each cable type (Bison and Buffalo). Earth wires were slightly cheaper and OPGW (Optical Fibre Ground Wire) was slightly more expensive. Averages of the standard line configuration were used: for 330kV the average of twelve conductors, one ground wire and one OPGW; and for 132kV six conductors and one OPWG. Small accessories were included in the wire cost calculation per kilometre on a reasonable engineering basis. The resulting wire unit costs used as part of the model are:

	C+F USD)	E (USD)	LTE (NGN)
330kV wire per km	6,563	770	115,678
132kV wire per km	3,302	264	67,927

The detailed breakdown of what is included in these numbers is given in Annex 7:.

Wayleaves

Wayleave costs in Nigeria are high. They vary significantly by region and indeed within regions. There have been cases where the incumbents have asked for greater wayleaves than the cost of the line – in which case TCN or NIPP would chose a different route. The percentages below were provided by NIPP and agreed with TCN.

Average wayleave costs as a percentage of total line asset costs for each region are:

Wayleave Costs	Benin	Bauchi	Enugu	Kaduna	Lagos	Oshogbo	Port Harcourt	Shiroro
Wayleave Costs as % of total construction cost	20%	33%	33%	20%	40%	20%	40%	20%

4.4.3 New substation unit costs

The substation data from NIPP was provided to us broken into 128 different cost items. From these we derived the costs for the cost drivers discussed in section 4.2. For those items where we did not have costs quoted directly we used cost ratios (derived from NIPP and UK data) in terms of size (MVA/MVAr) and voltage. These were 132/33kV 100MVA transformers, 40MVAr 132kV capacitors and 20MVAr 33kV capacitors.

Circuit breaker bays (CB)

The total costs it the three categories for 330kV, 132kV and 33kV circuit breaker bays are as follows:

DESCRIPTION	C+F (USD)	E (USD)	LTE (NGN)
330kV CB Bay	522,256	47,390	21,626,999
132kV CB Bay	198,258	27,377	10,777,143
33kV CB Bay	125,459	5,033	5,327,791

See Annex 7: for a more detailed breakdown of included costs.

Transformers

The total costs it the four categories for 330/132kV 300 and 150MVA transformers, and 132/33kV 100 and 60MVA transformers are as follows:

DESCRIPTION	C+F (USD)	E (USD)	LTE (NGN)
330/132kV 300MVA TX	2,986,294	78,391	43,392,289
330/132kV 150MVA TX	2,395,919	63,024	33,837,289
132/33kV 100MVA TX- *derived*	1,313,915	44,084	16,741,034
132/33kV 60MVA TX	1,125,149	37,750	14,335,900

See Annex 7: for a more detailed breakdown of included costs.

The 132/33kV 100MVA transformer cost was derived from the 132/33kV 60MVA transformer cost using an increase of 16.67% which is linearly derived from the increase in price between the 330/132kV transformers.

Reactors and Capacitors

The total costs it the three categories for 330kV 75MVAR reactor, 132kV 40MVAR and 33kV 20MVA capacitors are as follows:

DESCRIPTION	C+F (USD)	E (USD)	LTE (NGN)
330kV 75MVA Reactor	1,520,913	36,974	30,030,000
132kV 40MVA Capacitor - *derived*	1,044,867	25,401	20,630,610
33KV 20MVA Capacitor - *derived*	696,578	16,934	13,753,740

See Annex 7: for a more detailed breakdown of included costs.

The 132kV 40MVA capacitor cost was derived from the equivalent cost in the UK multiplied by a factor of 1.51 (derived from comparing the 330/132kV 150MVA transformer cost with its equivalent UK cost). The 33KV 20MVA capacitor was derived from the 132kV 40MVA capacitor using a reduction of 33% (derived from equivalent UK costs).

Substation general

The total costs it the four categories for 330/132/33kV, 330/132kV, 330kV and 132/33kV substations are as follows:

DESCRIPTION	C+F (USD)	E (USD)	LTE (NGN)
330/132/33kV Substation	927,408	242,946	7,941,400
330/132kV Substation	927,408	242,946	7,941,400
330kV Substation	816,229	225,272	7,941,400
132/33kV Substation	795,534	220,503	7,491,400

See Annex 7: for a more detailed breakdown of included costs.

Compared to our substation cost of around $1.25m TCN quoted a figure of around $6m. We believe this to be due to classification differences. If we include foundations, busbar steelwork control panels (included in our circuit breaker bay costs) in substation general we get a cost of around $5.5m.

4.4.4 Substation expansion unit costs

As previous noted substation expansion was defined as the addition of new circuits and/or new transformers at existing voltages at existing substations. Costs were therefore limited to transformers and circuit breaker bays as defined above.

4.4.5 Modelling assumptions

Lines

For each new line under consideration additional characteristics were calculated based on the following assumptions:

- Total number of towers based upon tower spacing of 452m for 330kV and 316m for 132kV. These are actual numbers calculated as the average number of towers per km for TCN existing lines;
- Number of suspension towers and tension towers based upon assumptions that 12.5% of all towers are tension towers. These estimates are based on advice from TCN.
- Total numbers of insulators for each line was calculated by a combination of:
  - the number of suspension towers;
  - the number of tension towers;
  - the number of insulators per suspension tower based on one insulator string per phase;
  - the number of insulators per tension tower based on two insulator strings per phase.
- The total number of conductors for each line was calculated (number of circuits times three phases per circuit times number of conductors per phase). In addition one additional conductor was added to allow for one Optical Ground Wire (OPGW) at 132kV and two additional conductors were added to allow for one OPGW and one earth wire at 330kV. The costs of OPGW and earth wires are comparable to copper conductors (see section 4.4.2).

Substations

For each individual substation under consideration additional characteristics were calculated to allow costing based on the following assumptions:

- The number of reactors and capacitors was estimated at one wherever transformers have inputs or outputs at the respective voltage and zero elsewhere.
- The number of circuit breaker bays required.
  - For 330kV and 132kV this was estimated to be: the number of circuits at the respective voltage; plus the number of reactors and capacitors at the respective voltage; plus the number of transformers with inputs or outputs at the respective voltage; all times by 1.5 and rounded up to the nearest whole number.
  - For 33kV this was estimated to be: the number of transformers with outputs at the 33kV times by 1.5 and rounded up to the nearest whole number; plus the number of 33kV capacitors.

4.4.6 Timing of cash requirements

We have followed the practice currently used by NIPP when structuring payment terms within EPC contracts. This is as follows:

EPC Foreign (USD) costs:

- 15% on contract signing. We have assumed this is two years before the commissioning date;
- 85% on procurement start on receipt of a letter of credit. Further release conditions exist to draw down against the letter of credit however given the requirement to release funds upfront, we have assumed this is also two years before the commissioning date. It is required to be this way given one-year periods in the model.

EPC Local (NGN) costs:

Local costs are claimable as incurred up to 95% of the total local cost component of the EPC contract. 5% of the total is withheld as a success fee following commissioning of the asset. Experience on NIPP demonstrates the following schedule is appropriate:

- 15% two years before the commissioning date;

- 40% one year before the commissioning date;
- 40% the year of the commissioning date;
- 5% success fee one year after the commissioning date.

Wayleave costs

The timing of NIPP payments for wayleaves is not so clear-cut and indeed on occasion they have been left until after construction has started (making more onerous demands far more likely). For the purposes of this study we have assumed that wayleaves will be secured before the start of procurement and construction but after contract signing. We have therefore assumed wayleave costs fall two years before the commissioning date of the line in question.

Partially costed projects at the end of the study period

One result of these new build cost timings should be noted. We have included transmission projects in our costing that we consider necessary up to 2026 based on our loadflow. However, as result of our timing assumptions any project with a commission year of 2023 or later is not fully costed in our model as some or all costs do not fall into the study costing period. The following percentages of costs have been excluded by commission year (330kV transmission lines with relevant commission years have also been included for illustrative purposes).

Commission year	% of project costs excluded from total costing		330kV transmission lines with expected commission date in relevant years
	USD Costs	NGN Costs	
2023	0%	5%	SOKOTO – TMAFARA line (330kV; 2 circuit; 2 conductor; 125km) TMAFARA – GUSAU line (330kV; 2 circuit; 2 conductor; 85km)
2024	0%	40%	BALI – JALINGO line (330kV; 2 circuit; 2 conductor; 294km) GUSAU – KATSINA line (330kV; 2 circuit; 2 conductor; 125km) BALI – MAMBILLA line 1 (330kV; 2 circuit; 4 conductor; 139km) BALI – MAMBILLA line 2 (330kV; 2 circuit; 4 conductor; 139km)
2025	0%	75%	BALI – MAKURDI line (330kV; 2 circuit; 4 conductor; 139km)
2026	100%	100%	

4.5 Modelling NIPP buyout requirements

As previously stated explained in section 1.3, any existing or currently under construction NIPP transmission asset will, at some point, be handed over to the TSP. Estimating the cost to the TSP of building these assets from scratch provides an upper bound to the cost TSP should rationally be willing to pay for such assets if required to make such a payment.

4.5.1 Unit costs

The unit costs used for to model the value of NIPP assets are the same as those used to cost new build assets (see section 4.4).

4.5.2 Modelling assumptions

The modelling assumptions used for to model the value of NIPP assets are the same as those used to cost new build assets (see section 4.4.5) with the exception of reactors and capacitors. It was assumed that NIPP has not installed any reactors or capacitors at the substations they have built or expanded.

4.5.3 Timing of cash requirements

Any payments for NIPP assets have been treated as non-period specific. Costs have therefore been included as a one-off cost to be included or excluded as required.

4.6 Modelling refurbishment requirements

4.6.1 Unit costs

TCN transmission assets have suffered from decades of insufficient investment making refurbishment a vital short-term activity. A full estimation of refurbishment costs would require asset specific information on the physical condition of each asset and was therefore not undertaken. We have, however, estimated refurbishment costs on the basis of the age of individual assets. While this approach may not give an accurate refurbishment costing for each individual asset, we consider the total cost to be of acceptable accuracy.

Transmission refurbishment unit cost data for Nigeria is understandably scarce so percentages of new capital cost were applied according to three age categories. Percentages applied vary across the different types of line and substation cost to ensure as accurate a picture as possible. These percentages and justifications are given below.

		New (<10yrs)	Medium (10-24yrs)	Old (>=25yrs)	Justification
Lines	Route survey and corridor clearance	10%	35%	40%	No meaningful corridor clearance has been taking place. Given high growth rates and weather driven deterioration of access roads a significant percentage of original costs is required. With high growth rates even new circuits need refurbishment
	Towers	0%	3%	5%	Low percentage driven largely by vandalism.
	Insulators	2%	20%	100%	No maintenance – given corrosion and general damage would expect replacement in 25 years.
	Wires	0%	6%	30%	Annealing over time, sagging and hotspots.
Substations	Transformers – Loading =<60%	2%	15%	60%	No meaningful maintenance - copper hotspots, iron magnetic circuit breaks and general deterioration – heavy duty on tap-changers is a particular problem.
	Transformers – Loading >60%	2%	25%	80%	Loading increases wear and tear.
	Circuit Breaker Bays	5%	30%	80%	Continuous tripping leads to massive duty hence nearly full replacement after 25 years
	Reactors	2%	20%	50%	Similar to transformers but without tap-changers
	Capacitors	4%	30%	75%	capacitors have a much higher duty than reactors and are more fragile mechanically and electrically
	Substation General	0%	40%	60%	Sub-station buildings, fences etc. are massively below standard and most/all auxiliary items such as batteries are broken/missing.

4.6.2 Voltage support requirements

As stated in section 3.7, we consider it necessary in our engineering view to add new reactors and capacitors around the network as part of the refurbishment programme, in addition to the refurbishment of existing assets. The list of new reactors and capacitors is given in Annex 5: and is derived from our loadflow. The costs of these additional reactors and capacitors (as well as the associated additional circuit breaker bays) were calculated separately.

4.6.3 Modelling assumptions

For each individual existing line under consideration additional characteristics were calculated exactly as for new lines (see section 4.4.5). Despite being provided actual numbers of towers by TCN for a substantial proportion of existing lines the data was not comprehensive and therefore could not be used. (It was however used to generate the assumptions around tower spacing.)

For substations actual numbers of reactors and capacitors were used. The number of circuit breaker bays was estimated using the same logic as for new substations.

4.6.4 Timing of cash requirements

We have assumed that the refurbishment programme will last five years from 2014 to 2018. Without detailed information on the condition of individual assets prioritisation (and therefore timing) is not possible. Total estimated costs for each project have therefore been split evenly over the five year period on the assumption that overall the refurbishment programme is conducted at an even rate over the period.

4.7 Modelling maintenance requirements

4.7.1 Unit costs

TCN has a very poor maintenance record. Ensuring the required funds are available so adequate maintenance can be conducted is vital. While we managed to obtain TCN records on maintenance costs by asset we did not consider the numbers to be reliable. In our engineering view, overall costs were far too low, but in some individual cases costs were considered to be too high. We therefore elected to base maintenance costs on fractions of new capital cost in a similar fashion to refurbishment (see above). The following assumptions were made:

- The cost of patrolling lines is NGN500,000 per km
- The cost of maintaining corridors is NGN100,000 for 330kV lines and NGN50,000 for 132kV lines.
- Insulators have a 25 year replacement period. Given corrosion and general damage we would expect replacement in this period.
- Yearly maintenance of 330kV and 132kV towers is around 1.5% of new build capital cost. We had originally considered extracting foundation costs however following discussions with TCN we realised that we had not allowed for erosion effects so we left then in to compensate. This is largely driven by vandalism/theft – tower members are removed until they fall and the circuit grounds out then Tower and wires are stolen.
- Yearly maintenance of 330kV wire is around 2.5% of new build capital cost. This is linked with towers above also there is clearance and maintaining access roads.
- Yearly maintenance of 132kV wire is around 3.5% of new build capital cost. Lower voltage makes vandalism/theft easier.
- Yearly maintenance of 330kV circuit breaker bays is approximately 3.5% of new build capital cost. Very regular tripping leads to massive duty hence a high maintenance cost for the active part of the circuit breaker bay.
- Yearly maintenance of 132kV circuit breaker bays is approximately 4.5% of new build capital cost. There are significantly more trips per year at 132kV than at 330kV.
- Yearly maintenance of 33kV circuit breaker bays is approximately 8% of new build capital cost. There are significantly more trips per year at 33kV than at 132kV.
- Yearly maintenance of transformers is around 2.5% of new build capital cost. High loading on transformers and heavy tap-changing increases the maintenance on these relatively robust items.
- Yearly maintenance of reactors is around 2% of new build capital cost. Similar to transformer costs but without tap-changers.

- Yearly maintenance capacitors is around 5% of new build capital cost. Similar to transformer costs but capacitors require significantly more maintenance.
- Yearly maintenance of other substation items is around 2.5% of new build capital cost. A varied pot of items some such as A/Cs probably need replacement within 10 years whereas buildings are more robust, other items such as batteries etc. will depend upon duty and care.

4.7.2 Modelling assumptions

Additional asset characteristics were derived as previously discussed according to the type of asset (existing, NIPP or new). For these treatments see sections 4.6.3, 4.5.2 and 4.4.5 respectively.

4.7.3 Timing of cash requirements

Maintenance cost timings follow the following logic:

- For existing assets yearly maintenance costs were included for every year. In the first five years this is in addition to any refurbishment costs;
- For new build assets (including any new assets resulting from substation expansion) yearly maintenance costs start the year after commissioning;
- For NIPP assets yearly maintenance costs start the year after commissioning or the start of the period whichever is later. This is in line with the assumption made in section 1.3 on the treatment of maintenance of NIPP assets.

The only exception to this logic is the case of additional reactors and capacitors (and associated circuit breaker bays) included for voltage support as part of the refurbishment programme. Given their categorisation as refurbishment costs they are not time specific but in contrast to the rest of the refurbishment programme they include the installation of new assets. For simplicity we have assumed that they are all installed in year two and yearly maintenance costs should start in year three.

5 ANCILLARY SERVICES

Ancillary services are provided by generators to ensure that the power system is operated at stable frequency and voltage and that it can be returned from a complete system collapse. This is a major cost item for the system operator. The three services and their cost drivers are:

4. Frequency control and reserve provision – This requires operating generating units not fully loaded which decreases their efficiency. It also implies increased wear and tear of continually increasing and decreasing output increases maintenance.
5. Voltage Control and MVAR – This requires operating generating units at higher rotor, stator and transformer currents to provide or absorb MVAR in order to control system voltages. This increases losses and maintenance costs.
6. Black Start – In order to start the system from dead power stations must have auxiliary generation capacity and associated batteries. This capability must be tested regularly and staff must be trained in the process and procedures which leads to on-going costs for the generator that need to be paid for, irrespective of whether the capability is utilized. When a black start occurs the generator must also be paid for the costs of doing it.

These costs were modelled independent of the main costing model, based on spreadsheets previously devised for TCN by NIAF. Costs are based on the following assertions:

a. Frequency control and reserve provision:
b. We estimate hydro generation reserve cost at 750 NGN/MW/hr. We estimate 100MW of hydro generation reserve is required between 2014-19 and140MW between 2020-23.
c. We estimate steamer reserve cost at 1200 NGN/MW/hr – this is higher due to increased maintenance cost. We estimate 100MW of steamer generation reserve is required between 2014-19 and140MW between 2020-23.

d. We estimate OCGT reserve cost at 2250 NGN/MW/hr – the efficiency drop on deloading for gas turbines is 6 times that for steamers. We estimate 100MW of OCGT generation reserve is required between 2014-19 and140MW between 2020-23.

e. We estimate standby reserve price at 200 NGN/MW/hr. We estimate 300MW of re generation reserve is needed between 2014-19 and 400MW between 2020-23.

2. Voltage Control and MVAR:

   a. We estimate the cost for exported MVAR is 200.85 NGN/MVARh and exported MVARs will increase from 225 in 2014 to 3048 by 2023.

   b. We estimate the cost for imported MVAR is 129.7 NGN/MVARh and imported MVARs will increase from 0 in 2014 to 656 by 2023.

3. Black Start:

   a. We estimate the monthly charge is 4,589,091 NGN

   b. We estimate the average successful black start charge as 8,580,000 NGN per station. The number of black starts is expected to fall from 20 in 2014 to 3 in 2023.

   c. We estimate the successful black start test charge is 5,728,091 NGN. Only one test is expected to be needed between 2014-23 given high numbers of actual black starts. This falls in 2023.

6 OTHER CAPITAL REQUIREMENTS

While the vast majority of TCN capex will be undertaken by the TSP in the form of new build and refurbishment, there are a number of relatively small, but crucial investments that must also be made over the period.

6.1 Other TSP Capex

In discussion with TSP staff three areas for additional TSP capital investment were identified, namely:

- Planning specific IT investment (particularly software licences);
- Geographical Information System (GIS); and
- Management Information System (MIS).

6.1.1 Planning specific IT investment

For the purposes of this exercise we have assumed that the SO purchase five PSSE licences (or equivalent) in year 1 and two PSSE licences in year 2. They cost around $50,000 each.

We have assumed they will need to be repeated in five years' time.

6.1.2 Geographical information system

Our GIS costs are based on estimates provided by NIAF's GIS expert. Assuming 10 transmission planning staff will need access to GIS software the costs have been calculated as follows.

	Unit	Price per unit	No. of units	Costs (GBP)
Arc GIS desktop	one user	7,000	10	70,000
ARC GIS server	one server	20,000	1	20,000
MS SQL server	five users	2,000	2	4,000
Total Cost				94,000

This has been included as a one off cost in 2014 as USD141,000.

6.1.3 Management information system

Despite the wishes of TSP staff to see a management information system (MIS) included in the budget they were unable to provide a costing or a specification of requirements to allow independent costing.

No cost was therefore included in the model for this element.

6.2 SO Capex

We identified four areas for SO capital investment, namely:

- SCADA
- Telecoms
- New National Control Centre
- Planning specific IT investment (particularly software licences)

6.2.1 SCADA

A SCADA (Supervisory Control And Data Acquisition) system is vital for the proper control of a modern power system. The current SCADA implementation project started in 2005 when a contract was signed with Siemens Nigeria. It suffered three main problems:

- Arguments around funds resulted in the project grinding to a halt in 2010;
- TCN did not complete all the wiring of sub-stations in connecting the measurement, indication and control points to the RTUs due to a lack of funding; and
- Almost all of the equipment put in by the contractor was obsolete on installation.

As a result, a recovery project has been put in place with the following features: Siemens Germany was brought in to reactivate the complete SCADA System; and TCN instituted a programme in complete the wiring in sub-stations. It is intended that 330kV substations and power stations will be fully reactivated by December 2013 although it is growing increasing unlikely that this deadline will be met completely.

This reactivation project does not however cover replacing the obsolete equipment, which needs to be done in parallel with the creation of a new national control centre and an additional regional control centre (see below) and the energy management system functionalities of the SCADA system needs to cover all the requirements of a fully proficient SO. Our SCADA expert (currently advising TCN) has costed the implementation of these requirements in detail and we have a capital expenditure of US$3,887,000 in 2014 and of US$32,500,000 in 2015.

Given the growth in the system and ongoing upgrading of SCADA capability our SCADA expert's view is that there will be a need for an annual capital expenditure of US$4 million. It is expected that towards the end of the study the SO will institute a project to replace the obsolete components within the SCADA system. We have allowed a capital expenditure of US$35 million in 2023 for implementation of this project.

6.2.2 Telecoms

Robust, reliable and redundant telecoms are a necessity for the operation of a power system. This results from the basic need to give verbal instruction to other operators on the system, up to the requirement to flow the data and the controls in the SCADA system. Quality modern power systems have multiple telecoms systems (there are examples of having up to eight across the network). The primary reason is that when the power system is lost this lack of power will often shut down parts or all of the various telecom systems: this is at a time when reliable communication is most vital.

The NIAF recommendation is for a minimum of three fully independent telecoms systems and the current telephone landline network is unreliable; indeed practically non-existent. Mobile telephony is not considered a viable solution since it is barely acceptable for verbal instructions (given bad sound quality and lack of recording) and is of little use for data handling. The primary media used by power companies is fibre-optics embedded in the earthing wire of overhead lines but in Nigeria this is also problematic given problems with vandalism and maintenance. Other methods are microwave which is independent of the power system and power line carrier which utilises the primary line conductors. All three of these methods are being used but in general the methodologies used are out-of-date and the equipment is sub-standard and often broken.

NIAF's telecoms expert (currently advising TCN) has put in place a detailed recovery plan for TCN and estimated the costs. There is a capital expenditure of US$22,325,000 in 2014 and of US$ 1,170,000 in 2015 to overhaul the telecoms system in support of the SCADA reinstatement.

We expect that there will be ongoing telecoms capital expenditure as the system expands and have allowed US$2 million per year to cover this. We have also put in a capital expenditure of US$20 million in 2022 to cover upgrading the telecoms system to support the future SCADA system

6.2.3 New National Control Centre

As part of the current SCADA implementation project a new control centre was built and completed in 2010, however considered wholly insufficient by NIAF advisers for the following reasons:

- The control room is very cramped with barely space for three control engineers to perform their duties.
- There is no specialist training room to allow operators to practice and gain skills in an insulated control room environment.
- There are no meeting/presentation rooms.
- Telecoms and SCADA equipment rooms are cramped.
- The office room provided are barely enough for telecoms, SCADA and general IT staff.
- The NCC manager, the operational planning department and all the other day staff have to be housed in the old decrepit control centre building.
- The standby electricity supplies are not considered adequate redundancy and indeed are only just functional.
- Perhaps most importantly, for the new electricity market the system operator will be required to support the market operator this will mean the need for a separate economic control room – which must be housed as well.

As part of the SCADA refurbishment there is a plan in place to put in a new control centre which our SCADA expert has costed as US$72,800,000 falling in 2015. These costs cover a fully functional building, fully redundant standby generation, moving the SCADA equipment, and other required costs.

6.2.4 New Regional Control Centre

Currently, the Delta area is a significant load centre in the Nigerian power network and it is expected to grow, in order to improve the economic network operation of this area, it is proposed that a new separated regional control centre to be built in the Delta Area at the same time as the new national control centre. The cost is expected to be US$80,000,000, which will cover a fully functional building, fully redundant standby generation, SCADA and telecommunication equipment and other required costs. This has been scheduled for 2015, the same year as the new National Control Centre to allow both control centres to be contracted simultaneously.

6.2.5 Planning specific IT investment

For the purposes of this exercise we have assumed that the SO purchase five PSSE licences (or equivalent) in year 1 and two PSSE licences in year 2. They cost around $50,000 each.

We have assumed they will need to be repeated in five years' time.

6.3 MO Capex

We have identified two areas for MO capital investment, namely:

- Settlement System
- Automatic Meter Reading (AMR) System

6.3.1 Settlement system

A settlement system is operated by an electricity system market operator to correlate and aggregate meter and other data concerning electricity flows, purchases and sales on the power system. Typically the basic output is a monthly settlement to each participant telling them in detail what electricity they have flowed onto and out of the system. The amount of data flowing is normally large and its commercial importance is high hence the settlement system is a non-trivial budget item. Settlement System capital cost in a slightly complex market can run up to hundreds of millions of dollars. A significant reason for these costs is that the software is essentially bespoke given the exact rules of an individual electricity market. In addition the settlement system must have full cross-checking and verification and a secure IT hardware environment.

For the Transition Electricity Market (soon to be put in place) the settlement system covers the monthly energy flows of participants and the daily capacity of generating units. It also covers their payments to service providers, being: SO, MO, TSP, NBET and NERC.

A settlement system has been put in place by the MO, however we have no evidence of it being successfully tested and are not convinced it will be adequate for the market. In addition the current market rules do not allow for distribution company imbalances which will significantly increase the complexity of the market rules and hence the settlement system. We have put US$10 million capital costs for a new settlement system in 2015.

6.3.2 Automatic Meter Reading (AMR) System

An Automatic Meter Reading system is an IT system for remotely and automatically collecting data from the commercial meters on the system and then storing the data in a database.

An AMR has been purchased by TCN and is being made operational. However as the system expands new meters will come online and new linkages will need to be put in place. The new connecter will be required to put commercial metering in place at the connection boundary points. These meters must be capable of communicating with the external world using mobile telephony. The MO will need to put in place the actual communication and update the AMR. Then it and its communication with the AMR must be tested. There are about twenty five new commercial metering systems being put in place each year so we have included an annual capital spend of US$100,000 per year to allow for this.

7 OPERATING COST REQUIREMENTS (EXC. TSP MAINTENANCE)

7.1 Methodology

Operating costs (excluding TSP asset maintenance) is in many ways the hardest area to calculate financial requirements given a lack of relevant benchmarking information. The following sources were considered and dismissed as part of the research for this study:

- Existing TCN operating budgets – While directly relevant to the organisation the existing operating budgets are largely not appropriate to the way TCN should be operating in future. For example we consider staffing levels to be too high but salaries too low for TCN divisions to operate in future. Despite a very large amount of information (hundreds if not thousands of budget lines) in TCN operating budgets, it is not clear if they correctly allow for expected TCN future functions.
- International benchmarks – Operating costs are largely locally driven (particularly staff costs) so relevance is somewhat limited. In addition even relatively minor variations in sector structures and allocations of responsibilities can have large impacts on the distribution of operating costs to various sector participants.

As a result of these limitations we have instead undertaken a relatively simplistic estimation of costs that outputs numbers we consider reasonable. The estimation was undertaken by considering:

- Functions of each TCN division and the professional staffing complement required for each function;
- An estimated number of support staff required per professional staff member;
- Generic organisational costs based upon the staffing complement (professional and support) for each TCN division;

- Division specific costs related to their intended function.

In order to allow for any future division or otherwise of TCN (as well as further simplifying the model) support functions such as IT, HR and legal are costed within each of the three divisions. We have therefore made no allowance for non-division specific costs.

7.2 Generic assumptions

For generic organisational costs we made assumptions that were applied across the three divisions. They are:

Generic organisational costs - TSP, SO and MO	
No of professional staff per support staff	2
Salary, pensions, other benefits and taxes per professional staff (NGN)	8,500,000
Salary, pensions, other benefits and taxes per support staff (NGN)	1,700,000
Office costs per professional or support staff (NGN)	200,000
IT costs per professional staff (NGN)	300,000
IT costs per support staff (NGN)	100,000
Training per professional staff (NGN)	500,000
Training per support staff (NGN)	100,000
Communications per professional staff (NGN)	120,000
Communications per support staff (NGN)	60,000
Transportation per professional staff (NGN)	500,000

7.3 TSP operating costs

Our methodology for new build, refurbishment and maintenance costs (determined by NIPP cost information) is based on Engineering, Procurement and Construction (EPC) contract costings. This implies an approach to construction reliant largely on contracting out. In order to avoid the duplication of costs we have therefore estimated the staffing complement to procure and manage such contracts (and not to conduct the works in house). This is not intended as a judgement on the value of either contracting out or undertaking works in house.

The following functional areas for the TSP were identified:

- Asset monitoring
- New Build: Procurement, management and supervision
- Refurbishment: Procurement, management and supervision
- Maintenance: Procurement, management and supervision
- Transmission protection
- Standards and safety
- Transmission planning
- Stores and stock management
- Billing and collections
- Regulatory and Government interface
- Public relations
- Legal (in-house)

- IT
- Finance
- HR
- Central management

Estimates of the number of professional staff by function by year, as well as total support staff are given in Annex 8:.

In addition to generic TSP costs based on staffing levels, the following costs (and their assumptions) were also included

Specific costs - TSP	
Cost of client engineers as % of new build cost	0.10%
Cost of client engineers as % of refurbishment cost	0.05%
No. of site visits per year per engineering staff (asset monitoring, new build, refurb or maintenance)	12
Cost per site visit (inc security where needed) per person (NGN)	150,000
No of international factory visits per new build staff per year	1
International factory visits (new build) per visit per person (USD)	4,000
Legal (outside support) per year (USD)	1,000,000

The breakdown of estimated TSP costs is given in 0 and a summary is provided in section 0.

7.4 SO operating costs

The following functional areas for the SO were identified:

- Control staff (at National Control Centre, regional control centres and sub-regional control centres)
- Operational planning, monitoring and post event (at National Control Centre, regional control centres and sub-regional control centres)
- SCADA and telecoms management (at National Control Centre and regional control centres)
- Management (at National Control Centre, regional control centres and sub-regional control centres)
- Telecom management (at head office)
- SCADA management (at head office)
- System Planning (at head office)
- System Protection (at head office)
- Ancillary service management and training of participants (at head office)
- Regulatory and Government interface
- Public relations
- In-house legal
- IT
- Finance
- HR
- Central management

Estimates of the number of professional staff by function by year, as well as total support staff are given in Annex 8:.

In addition to generic SO costs based on staffing levels, the following costs (and their assumptions) were also included

Specific costs - SO	
Telecoms maintenance per year (USD)	6,265,000
SCADA maintenance per year (USD)	2,873,000
Planning specific IT costs (PSSE etc) per planning staff (USD)	10,000
Legal (outside support) per year (USD)	250,000

The breakdown of estimated SO costs is given in 0 and a summary is provided in section 0.

7.5 MO operating costs

The following functional areas for the SO were identified:

- Metering
- Settlement
- Treasury
- Market Development
- Regulatory and Government interface
- Industry relations
- Public relations
- Legal (in-house)
- IT
- HR
- Finance
- Central Management

Estimates of the number of professional staff by function by year, as well as total support staff are given in Annex 8:.

In addition to generic MO costs based on staffing levels, the following costs (and their assumptions) were also included

Specific costs - MO	
AMR maintenance per year (USD)	50,000
Settlement sys maintenance per year (USD)	50,000
Legal (outside support) per year (USD)	250,000
Banking charges (NGN)	7,500,000

The breakdown of estimated SO costs is given in 0 and a summary is provided in section 0.

8 Findings

Our findings are presented below. When interpreting these findings the following should be taken into consideration.

- All numbers are given in 2013 constant prices.
- Costs in foreign currency (USD) and local currency (NGN) are calculated and stated completely independently. USD values represent a different set of costs to those costs represented by the NGN values. This avoids having to make foreign exchange assumptions and allows for differing treatment of inflation by currently on conversion to nominal values.

8.1 Overall findings

	USD (Constant 2013 prices)	NGN (Constant 2013 prices)
Total (2014-2023)	**6,505,424k**	**622,188m**
TSP Capital Expenditure	**3,919,952k**	**245,573m**
New Lines	1,254,397k	175,536m
New Substations	1,093,634k	23,549m
Existing Substations Expansion	587,030k	15,826m
Line Refurbishment	199,551k	9,490m
Substation Refurbishment	785,340k	21,171m
Other capital costs	841k	-
TSP Operating Expenditure	**1,386,367k**	**104,925m**
Line Maintenance	443,772k	44,444m
Substation Maintenance	837,459k	23,754m
Staff costs	-	24,511m
Other costs	105,135k	12,217m
SO Capital Expenditure	**309,382k**	-
SO Operating Expenditure	**103,380k**	**87,483m**
Staff costs	-	73,032m
Other costs	103,380k	14,451m
MO Capital Expenditure	**11,000k**	-
MO Operating Expenditure	**3,500k**	**8,536m**
Staff costs	-	7,064m
Other costs	3,500k	1,473m
NIPP Buyout (Upper Bound)	**771,843k**	**68,960m**
Lines	348,696k	58,108m
Substations	423,147k	10,851m
Ancillary Services	-	**106,711m**

8.2 New line costs breakdown

USD Requirements

	Corridor Costs	Tower Costs	Insulator Costs	Wire Costs	Wayleave Costs	Total
2014	-	114,692k	21,151k	123,831k	-	259,674k
2015	-	28,510k	5,540k	28,225k	-	62,276k
2016	-	71,330k	12,829k	87,265k	-	171,425k
2017	-	39,271k	7,135k	49,886k	-	96,292k
2018	-	48,250k	8,591k	62,973k	-	119,814k
2019	-	63,826k	11,131k	81,481k	-	156,438k
2020	-	25,084k	4,553k	24,414k	-	54,051k
2021	-	34,700k	6,213k	32,667k	-	73,581k
2022	-	79,818k	12,848k	134,052k	-	226,718k
2023	-	19,979k	3,766k	10,384k	-	34,129k
Total	-	**525,460k**	**93,758k**	**635,179k**	-	**1,254,397k**

NGN requirements

	Corridor Costs	Tower Costs	Insulator Costs	Wire Costs	Wayleave Costs	Total
2014	3,211m	5,567m	16m	764m	16,188m	25,746m
2015	2,764m	5,314m	14m	801m	5,130m	14,023m
2016	3,115m	6,070m	16m	914m	10,388m	20,502m
2017	3,179m	6,260m	16m	944m	7,247m	17,646m
2018	3,415m	7,026m	17m	1,074m	6,921m	18,453m
2019	3,072m	6,516m	15m	1,004m	8,348m	18,955m
2020	3,113m	6,791m	16m	1,040m	3,285m	14,245m
2021	2,673m	5,571m	14m	827m	4,234m	13,319m
2022	2,390m	4,895m	12m	774m	11,559m	19,631m
2023	2,946m	6,495m	15m	1,132m	2,428m	13,016m
Total	**29,877m**	**60,506m**	**149m**	**9,274m**	**75,730m**	**175,536m**

8.3 New substation breakdown

USD Requirements

	Structure Costs	Transformer Costs	Circuit Breaker Bay Costs	Reactor and Capacitor Costs	Total
2014	37,349k	96,556k	96,586k	69,151k	299,642k
2015	10,160k	23,258k	23,270k	17,838k	74,527k
2016	15,395k	37,479k	40,554k	27,601k	121,029k
2017	9,299k	23,524k	24,882k	16,898k	74,604k
2018	11,485k	30,768k	33,476k	21,310k	97,039k
2019	10,186k	20,932k	31,197k	16,054k	78,369k
2020	8,128k	18,606k	18,616k	14,270k	59,621k
2021	12,501k	33,094k	35,803k	23,094k	104,492k
2022	13,388k	28,043k	46,105k	22,250k	109,786k
2023	10,160k	23,258k	23,270k	17,838k	74,527k
Total	**138,052k**	**335,518k**	**373,759k**	**246,305k**	**1,093,634k**

NGN requirements

	Structure Costs	Transformer Costs	Circuit Breaker Bay Costs	Reactor and Capacitor Costs	Total
2014	135m	603m	2,095m	659m	3,492m
2015	96m	428m	1,505m	471m	2,500m
2016	94m	395m	1,443m	447m	2,379m
2017	91m	370m	1,401m	425m	2,287m
2018	89m	380m	1,433m	422m	2,323m
2019	77m	338m	1,311m	368m	2,094m
2020	76m	310m	1,304m	346m	2,036m
2021	72m	278m	1,192m	321m	1,863m
2022	79m	326m	1,327m	368m	2,099m
2023	90m	363m	1,609m	415m	2,477m
Total	**898m**	**3,792m**	**14,619m**	**4,240m**	**23,549m**

8.4 Summary substation expansion financial requirements

USD Requirements

	Transformer Costs	Circuit Breaker Bay Costs	Reactor and Capacitor Costs	Total
2014	24,589k	73,709k	48,757k	147,056k
2015	25,801k	19,257k	13,818k	58,876k
2016	23,342k	46,555k	25,889k	95,786k
2017	9,836k	27,254k	16,352k	53,441k
2018	19,030k	24,964k	17,422k	61,416k
2019	8,588k	26,104k	17,422k	52,114k
2020	4,918k	13,583k	10,120k	28,620k
2021	3,065k	11,282k	10,703k	25,049k
2022	7,983k	19,815k	14,889k	42,687k
2023	-	11,282k	10,703k	21,984k
Total	**127,151k**	**273,805k**	**186,074k**	**587,030k**

NGN requirements

	Transformer Costs	Circuit Breaker Bay Costs	Reactor and Capacitor Costs	Total
2014	118m	1,213m	404m	1,735m
2015	165m	1,194m	348m	1,707m
2016	288m	1,394m	386m	2,068m
2017	305m	1,365m	377m	2,047m
2018	241m	1,417m	389m	2,048m
2019	195m	1,128m	336m	1,658m
2020	171m	1,002m	314m	1,487m
2021	95m	811m	260m	1,166m
2022	67m	643m	220m	930m
2023	65m	676m	238m	979m
Total	**1,711m**	**10,843m**	**3,272m**	**15,826m**

8.5 NIPP line costs breakdown

USD Requirements

	Corridor Costs	Tower Costs	Insulator Costs	Wire Costs	Wayleave Costs	Total
Total	-	123,866k	24,274k	200,556k	-	**348,696k**

NGN requirements

	Corridor Costs	Tower Costs	Insulator Costs	Wire Costs	Wayleave Costs	Total
Total	8,301m	18,454m	44m	3,214m	28,095m	**58,108m**

8.6 NIPP substation breakdown

USD Requirements

	Structure Costs	Transformer Costs	Circuit Breaker Bay Costs	Reactor and Capacitor Costs	Total
Total	**63,750k**	**154,340k**	**205,057k**	**-**	**423,147k**

NGN requirements

	Structure Costs	Transformer Costs	Circuit Breaker Bay Costs	Reactor and Capacitor Costs	Total
Total	**457m**	**2,030m**	**8,364m**	**-**	**10,851m**

8.7 Line refurbishment breakdown

USD Requirements

	Corridor Costs	Tower Costs	Insulator Costs	Wire Costs	Total
2014	-	5,071k	11,170k	23,669k	39,910k
2015	-	5,071k	11,170k	23,669k	39,910k
2016	-	5,071k	11,170k	23,669k	39,910k
2017	-	5,071k	11,170k	23,669k	39,910k
2018	-	5,071k	11,170k	23,669k	39,910k
Total	**-**	**25,357k**	**55,849k**	**118,345k**	**199,551k**

NGN requirements

	Corridor Costs	Tower Costs	Insulator Costs	Wire Costs	Total
2014	904m	585m	20m	389m	1,898m
2015	904m	585m	20m	389m	1,898m
2016	904m	585m	20m	389m	1,898m
2017	904m	585m	20m	389m	1,898m
2018	904m	585m	20m	389m	1,898m
Total	**4,521m**	**2,924m**	**99m**	**1,946m**	**9,490m**

8.8 Substation refurbishment breakdown

USD Requirements

	Substation General Costs	Transformer Costs	Circuit Breaker Bay Costs	Reactor and Capacitor Costs	Total
2014	12,746k	42,994k	70,190k	31,138k	157,068k
2015	12,746k	42,994k	70,190k	31,138k	157,068k
2016	12,746k	42,994k	70,190k	31,138k	157,068k
2017	12,746k	42,994k	70,190k	31,138k	157,068k
2018	12,746k	42,994k	70,190k	31,138k	157,068k
Total	**63,732k**	**214,972k**	**350,948k**	**155,688k**	**785,340k**

NGN requirements

	Substation General Costs	Transformer Costs	Circuit Breaker Bay Costs	Reactor and Capacitor Costs	Total
2014	92m	552m	2,990m	600m	4,234m
2015	92m	552m	2,990m	600m	4,234m
2016	92m	552m	2,990m	600m	4,234m
2017	92m	552m	2,990m	600m	4,234m
2018	92m	552m	2,990m	600m	4,234m
Total	**461m**	**2,760m**	**14,950m**	**3,001m**	**21,171m**

8.10 Line maintenance breakdown

USD Requirements

	Existing Line Costs	New Line Costs	NIPP Line Costs	Total
2014	26,990k	-	3,579k	30,569k
2015	26,990k	1,002k	7,454k	35,446k
2016	26,990k	2,690k	7,521k	37,201k
2017	26,990k	5,993k	7,997k	40,981k
2018	26,990k	7,451k	7,997k	42,438k
2019	26,990k	11,370k	7,997k	46,357k
2020	26,990k	13,575k	7,997k	48,562k
2021	26,990k	16,302k	7,997k	51,289k
2022	26,990k	19,853k	7,997k	54,840k
2023	26,990k	21,102k	7,997k	56,089k
Total	**269,903k**	**99,337k**	**74,532k**	**443,772k**

NGN requirements

	Existing Line Costs	New Line Costs	NIPP Line Costs	Total
2014	2,907m	-	314m	3,221m
2015	2,907m	93m	647m	3,647m
2016	2,907m	244m	653m	3,804m
2017	2,907m	538m	694m	4,139m
2018	2,907m	669m	694m	4,270m
2019	2,907m	1,016m	694m	4,617m
2020	2,907m	1,221m	694m	4,822m
2021	2,907m	1,460m	694m	5,061m
2022	2,907m	1,774m	694m	5,375m
2023	2,907m	1,886m	694m	5,487m
Total	**29,069m**	**8,902m**	**6,474m**	**44,444m**

8.12 Substation maintenance breakdown

USD Requirements

	Existing Substation Costs	New Substation Costs	Expanded Substation Asset Costs	Voltage Support Asset Costs	NIPP Substation Costs	Total
2014	37,613k	-	-	-	13,189k	50,802k
2015	37,613k	2,762k	1,410k	-	13,857k	55,642k
2016	37,613k	6,827k	3,118k	7,656k	13,857k	69,071k
2017	37,613k	11,263k	6,669k	7,656k	13,857k	77,058k
2018	37,613k	14,220k	9,033k	7,656k	13,857k	82,379k
2019	37,613k	18,877k	12,585k	7,656k	13,857k	90,587k
2020	37,613k	21,698k	14,438k	7,656k	13,857k	95,263k
2021	37,613k	25,272k	16,728k	7,656k	13,857k	101,126k
2022	37,613k	28,319k	18,767k	7,656k	13,857k	106,212k
2023	37,613k	30,685k	19,510k	7,656k	13,857k	109,321k
Total	**376,129k**	**159,924k**	**102,256k**	**61,251k**	**137,899k**	**837,459k**

NGN requirements

	Existing Substation Costs	New Substation Costs	Expanded Substation Asset Costs	Voltage Support Asset Costs	NIPP Substation Costs	Total
2014	1,121m	-	-	-	389m	1,511m
2015	1,121m	75m	36m	-	411m	1,643m
2016	1,121m	184m	83m	176m	411m	1,975m
2017	1,121m	306m	178m	176m	411m	2,192m
2018	1,121m	388m	233m	176m	411m	2,329m
2019	1,121m	517m	328m	176m	411m	2,553m
2020	1,121m	595m	378m	176m	411m	2,680m
2021	1,121m	692m	434m	176m	411m	2,834m
2022	1,121m	780m	488m	176m	411m	2,976m
2023	1,121m	846m	507m	176m	411m	3,061m
Total	**11,214m**	**4,384m**	**2,665m**	**1,404m**	**4,087m**	**23,754m**

8.14 Other capex costs

USD Requirements

	TSP Other Capex Costs	SO Capex Costs	MO Capex Costs	Total
2014	391k	26,462k	100k	26,953k
2015	100k	186,570k	10,100k	196,770k
2016	-	6,000k	100k	6,100k
2017	-	6,000k	100k	6,100k
2018	-	6,000k	100k	6,100k
2019	250k	6,250k	100k	6,600k
2020	100k	6,100k	100k	6,300k
2021	-	6,000k	100k	6,100k
2022	-	26,000k	100k	26,100k
2023	-	34,000k	100k	34,100k
Total	**841k**	**309,382k**	**11,000k**	**321,223k**

8.16 Operating costs (exc. TSP maintenance) breakdown

USD Requirements

	TSP Other Opex Costs	SO Opex Costs	MO Opex Costs	Total
2014	18,437k	10,338k	3,579k	29,125k
2015	10,502k	10,338k	7,454k	21,190k
2016	15,201k	10,338k	7,521k	25,889k
2017	11,564k	10,338k	7,997k	22,252k
2018	12,748k	10,338k	7,997k	23,436k
2019	8,967k	10,338k	7,997k	19,655k
2020	5,437k	10,338k	7,997k	16,125k
2021	6,476k	10,338k	7,997k	17,164k
2022	10,774k	10,338k	7,997k	21,462k
2023	5,030k	10,338k	7,997k	15,718k
Total	**105,135k**	**103,380k**	**3,500k**	**212,015k**

NGN requirements

	TSP Other Opex Costs	SO Opex Costs	MO Opex Costs	Total
2014	4,037m	8,143m	759m	12,940m
2015	3,655m	8,278m	769m	12,702m
2016	3,934m	8,412m	804m	13,150m
2017	3,880m	8,547m	814m	13,240m
2018	3,905m	8,681m	849m	13,435m
2019	3,605m	8,815m	859m	13,280m
2020	3,400m	8,950m	893m	13,243m
2021	3,358m	9,084m	904m	13,345m
2022	3,569m	9,219m	938m	13,726m
2023	3,384m	9,353m	948m	13,685m
Total	**36,728m**	**87,483m**	**8,536m**	**132,747m**

Annex 1: Existing TCN Assets

Existing TCN Transmission lines

Line name	Geog'ical area	Voltage (V)	No. of circuits	No. of conductors	Length (km)	Year constructed	Year refurbished
OSOGBO - BENIN	BE	330	1	2	258	1964	
BENIN - ONITSHA	EN	330	1	2	137	1964	
AYEDE - OSOGBO	OS	330	1	2	115	1968	
OSOGBO - JEBBA T.S.	OS	330	1	2	157	1968	
JEBBA T.S. - KAINJI G.S.	SH	330	1	2	81	1969	
JEBBA T.S. - ZUNGERU	SH	330	2	2	229	1969	
SHIRORO - ZUNGERU	SH	330	2	2	8	1969	
SHIRORO - KADUNA	SH	330	2	2	96	1969	
AKANGBA - IKEJAW	LA	330	2	2	17	1975	
IKEJAW - OLORUNSOGO	LA	330	1	2	30	1975	
IKEJAW - OSOGBO	LA	330	1	2	250	1975	
OLORUNSOGO - AYEDE	OS	330	1	2	60	1975	
KADUNA - KANO	KA	330	1	2	230	1976	
OSOGBO - JEBBA T.S.	OS	330	1	2	157	1976	
BKEBBI - KAINJI G.S.	SH	330	1	2	310	1976	
BENIN - BENIN NORTH	BE	330	2	2	27	1978	
KADUNA - JOS	KA	330	1	2	196	1978	
EGBIN - OMOTOSO	LA	330	1	2	154	1978	
EGBIN - OGIJO	LA	330	1	2	40	1978	
IKEJAW - OGIJO	LA	330	2	2	30	1978	
OMOTOSO - OGIJO	LA	330	1	2	175	1978	
JEBBA T.S. - KAINJI G.S.	SH	330	1	2	81	1979	
EGBIN - OKEARO	LA	330	2	2	17.5	1980	
IKEJA W - OKEARO	LA	330	2	2	0.5	1980	
AFAM IV - ALAOJI	PH	330	2	2	25	1980	
GOMBE - JOS	BA	330	1	2	264	1981	
AJAOKUTA - BENIN	BE	330	2	2	195	1981	
NHAVEN - ONITSHA	EN	330	1	2	96	1982	
ONITSHA - ALAOJI	EN	330	1	2	138	1982	
DELTA IV - BENIN (extended to Benin north)	BE	330	1	2	95	1983	
ALADJA - DELTA IV	BE	330	1	2	32	1983	
ALADJA - SAPELE	BE	330	1	2	63	1983	
BENIN - SAPELE	BE	330	1	2	50	1983	
BENIN - SAPELE	BE	330	1	2	50	1983	
BENIN - SAPELE	BE	330	1	2	50	1983	
AJA - EGBIN	LA	330	2	2	14	1984	
OSOGBO - GANMO	OS	330	1	2	81	1984	
GANMO - JEBBA T.S.	SH	330	1	2	81	1984	

Line name	Geog'ical area	Voltage (V)	No. of circuits	No. of conductors	Length (km)	Year constructed	Year refurbished
JEBBA T.S. - JEBBA G.S.	SH	330	2	2	8	1984	
AJA - ALAGBON	LA	330	2	2	50	1985	
OMOTOSO - BENIN	OS	330	2	2	241	1985	
GOMBE - YOLA	BA	330	1	2	240	2001	
GOMBE - DAMATURU	BA	330	1	2	180	2001	
MAIDUGURI - DAMATURU	BA	330	1	2	260	2001	
YOLA - JALINGO	BA	330	1	2	160	2001	
KATAMPE - SHIRORO	SH	330	2	2	218	2003	
ONITSHA - OKPAI	EN	330	2	2	60	2005	
IKEJA W - SAKETE	LA	330	1	2	70	2007	
BENIN NORTH - ONITSHA	BE	330	1	2	142.7	2013	
BENIN - ONITSHA	EN	330	2	2	137	2013	
ASHAKA - ASHAKA RNDAB	BA	132	1	1	10	1977	
ASHAKA RNDAB - POTISKUM	BA	132	1	1	106	1977	
BIU - DAMBOA	BA	132	1	1	142	1977	
BIU - DADINKOWA	BA	132	1	1	82	1977	
DAMBOA - MAIDUGURI	BA	132	1	1	71	1977	
GOMBE - ASHAKA RNDAB	BA	132	1	1	76	1977	
GOMBE - BAUCHI	BA	132	1	1	146	1977	
GOMBE - DADINKOWA	BA	132	1	1	64	1977	
GOMBE - SAVANNAH	BA	132	1	1	69	1977	
GOMBI - SONG	BA	132	2	1	50	2013	
JOS - BAUCHI	BA	132	1	1	118	1977	
JOS - MAKERI	BA	132	2	1	50	1984	
JOS - KAFANCHAN	BA	132	2	1	77	2010	
MUBI - GOMBI	BA	132	2	1	50	2013	
MUBI - GULAK	BA	132	2	1	120	2013	
NUMAN - YOLA	BA	132	1	1	71	1977	
PANKSHIN - MAKERI	BA	132	2	1	90	1984	
SAVANNAH - NUMAN	BA	132	1	1	113	1977	
YOLA - SONG	BA	132	2	1	70	2013	
AJAOKUTA - OKENE	BE	132	1	1	60	1973	
BENIN - IRRUA	BE	132	1	1	88.8	1973	
BENIN - AMUKPE	BE	132	1	1	12	1966	2001
DELTA - BENIN	BE	132	1	1	107	1966	2001
DELTA - AMUKPE	BE	132	1	1	90	1966	2001
DELTA - EFFURUN	BE	132	1	1	36	1988	
IRRUA - UKPILLA	BE	132	1	1	43	1973	2001
OKENE - UKPILLA	BE	132	1	1	33	1973	2001
AJAOKUTA - GEREGU TS	BE	132	2	1	10	2002	
APIR - ALIADE	EN	132	1	1	25	2001	
AROCHUKWU - OHAFIA	EN	132	1	1	33	2013	

Line name	Geog'ical area	Voltage (V)	No. of circuits	No. of conductors	Length (km)	Year constructed	Year refurbished
AWKA - OJI RIVER	EN	132	1	1	33.35	1966	
MAKURDI - ALIADE	EN	132	1	1	47	1978	
MBALANO - UMUAHIA	EN	132	1	1	25	2013	
NHAVEN - NKALAGU	EN	132	2	1	39	1976	
NKALAGU - ABAKALIKI	EN	132	1	1	54	1976	
NHAVEN - OJI RIVER	EN	132	1	1	44.1	1976	2001
NHAVEN - OTURKPO	EN	132	1	1	25	1978	
NHAVEN - NSUKKA	EN	132	1	1	60	1975	
NNEWI - OBA	EN	132	2	1	22.5	2013	
NNEWI - IDEATO	EN	132	2	1	22.5	2013	
OHAFIA - UMUAHIA	EN	132	1	1	40	2013	
OKIGWE - MBALANO	EN	132	1	1	22	2013	
OKIGWE - IDEATO	EN	132	2	1	22.5	2013	
ONITSHA - AWKA	EN	132	1	1	30	1966	
ONITSHA - OBA	EN	132	2	1	22.5	2013	
ONITSHA - GCM	EN	132	1	1	8.05	1974	
OTURKPO - ALIADE	EN	132	1	1	25	1978	
YANDEV - ALIADE	EN	132	2	1	25	1978	
CALABAR - ITU	EN	132	1	1	84	1981	
AZARE - DUTSE	KA	132	2	1	43	2007	
DAKATA - WALALAMBE	KA	132	1	1	8	1980	
DAKATA - GAGARAWA	KA	132	1	1	134	1980	
DUTSE - WUDIL	KA	132	1	1	50.8	2007	
GAZOUA - KATSINA	KA	132	1	1	71.28	1994	
HADEJIA - GAGARAWA	KA	132	1	1	40	1980	
KADUNA - KADUNA TOWN	KA	132	2	1	20	1985	
KADUNA - ZARIA	KA	132	1	1	62	1968	
KANKIA - KATSINA	KA	132	1	1	69	1980	
KANO - KANKIA	KA	132	1	1	113	1980	
KANO - DUTSE	KA	132	1	1	108.5	2007	
KANO - KATSINA	KA	132	1	1	145	1985	
KANO - WALALAMBE	KA	132	1	1	10	1980	
KANO - WUDIL	KA	132	1	1	50	2007	
KANO - TAMBURAWA	KA	132	1	1	20	1968	
KANO - DAN-AGUNDI	KA	132	1	1	9	1968	
KWANARDANGO - ZARIA	KA	132	1	1	84.8	1968	
TAMBURAWA- KWANARDANGO	KA	132	1	1	40	1968	
ZARIA - FUNTUA	KA	132	1	1	70	1975	
AGBARA - OJO	LA	132	2	1	16.37	1989	
AKANGBA - ITIRE	LA	132	2	1	3	1975	
AKANGBA - AMUWO ODOFIN	LA	132	1	1	10	1977	
AKANGBA - APAPA RD	LA	132	1	1	4.5	1968	

Line name	Geog'ical area	Voltage (V)	No. of circuits	No. of conductors	Length (km)	Year constructed	Year refurbished
AKANGBA - IJORA	LA	132	2	1	8.3	1968	
AKANGBA - ISOLO	LA	132	2	1	4.5	1968	
AKOKA - ALAGBON	LA	132	1	1	12	1982	
AKOKA - IJORA	LA	132	1	1	8	1970	
AKOKA - OWOROSOKI	LA	132	2	1	4.45	1982	
ALAGBON - IJORA	LA	132	1	1	4	1970	
ALAUSA - OGBA	LA	132	2	1	2	1999	
ALIMOSHO - OGBA	LA	132	2	1	9.5	1976	
AMUWO ODOFIN - APAPA RD	LA	132	1	1	2	1970	
AMUWO ODOFIN - OJO	LA	132	2	1	8.9	1977	
EGBIN - IKORODU	LA	132	2	1	20	1987	
IGBOORA - LANLATE	LA	132	2	1	30	2013	
IGBOORA - IGANGAN	LA	132	2	1	40	2013	
IKEJA W - AGBARA	LA	132	2	1	32.04	1988	
IKEJA W - ALIMOSHO	LA	132	2	1	3.5	1976	
IKEJA W - EJIGBO	LA	132	2	1	13.32	1975	
IKEJA W - ILLUPEJU	LA	132	2	1	20	1996	
IKEJA W - OTTA	LA	132	2	1	12	1989	
IKEJA W - OWOROSOKI	LA	132	2	1	49	1982	
IKORODU - SHAGAMU	LA	132	1	1	35.9	1968	
ILLUPEJU - MARYLAND	LA	132	2	1	5.7	1996	
ITIRE - EJIGBO	LA	132	2	1	8	1975	
NEW ABEOKUTA - IGBOORA	LA	132	2	1	55	2013	
OGBA - OTTA	LA	132	1	1	44.3	1966	
PAPALANTO - OTTA	LA	132	1	1	30	1966	
PAPALANTO - ABEOKUTA	LA	132	1	1	40	1989	
SHAGAMU CEMENT	LA	132	1	1	33	1978	
SHAGAMU CEMENT	LA	132	1	1	55	1978	
ADOEKITI - AKURE	OS	132	1	1	47	1976	
AYEDE - IBADAN NORTH	OS	132	1	1	2	1958	
AYEDE - JERICHO	OS	132	2	1	2	1973	
GANMO - OGBOMOSO	OS	132	2	1	35	2013	
IBADAN NORTH - IWO	OS	132	1	1	18	1958	
IFE - ILESHA	OS	132	1	1	19.5	1981	
IFE - ONDO2	OS	132	1	1	18.3	1984	
ILORIN - OFFA	OS	132	1	1	50	1976	
IWO - ISEYIN	OS	132	1	1	71	1980	
OFFA - OMUARAN	OS	132	1	1	47.53	1977	
ONDO1 - ONDO2	OS	132	1	1	58.5	1977	
OSOGBO - AKURE	OS	132	1	1	9.3	1999	
OSOGBO - IFE	OS	132	1	1	15	1981	
OSOGBO - IWO	OS	132	1	1	20	1977	

Line name	Geog'ical area	Voltage (V)	No. of circuits	No. of conductors	Length (km)	Year constructed	Year refurbished
OSOGBO - OFFA	OS	132	1	1	35	1976	
SHAGAMU - IJEBUODE	OS	132	1	1	30	1982	
SHAGAMU - AYEDE	OS	132	1	1	30	1958	
ABOHMBAISE - OWERRI	PH	132	2	1	26	2013	
AFAM - ALAOJI	PH	132	2	1	46	1960	
AFAM - PHCT MAIN	PH	132	2	1	37.8	1960	
AHOADA - OMOKU	PH	132	2	1	15	2005	
AHOADA - OWERRI	PH	132	2	2	73	2005	
ALAOJI - ABA	PH	132	2	1	10	1960	
ALAOJI - UMUAHIA	PH	132	2	1	66	2012	
ALAOJI - OWERRI	PH	132	2	1	60	1983	
EKET - UYO	PH	132	1	1	46	1986	
ITU - UYO	PH	132	1	1	18	1986	
ITU - ABA	PH	132	1	1	85.4	1986	
PHCT MAIN - PHCT TOWN	PH	132	2	1	3	2008	
PHCT MAIN - ONNE	PH	132	2	1	10	2013	
PHCT MAIN - RIVERS IPP	PH	132	2	1	18.9	2009	
YENAGOA - AHOADA	PH	132	2	1	46	2005	
YENAGOA - GBARAINUBIE	PH	132	2	1	5	2005	
AKWANGA - KEFFI	SH	132	1	1	62	1983	
APO - KARU	SH	132	1	1	10	1983	
BIDA - MINNA	SH	132	1	1	90	1990	
BKEBBI - SOKOTO	SH	132	1	1	130	1976	
BKEBBI - DOSSO	SH	132	1	1	128	1976	
GUSAU - FUNTUA	SH	132	1	1	110	1975	
KARU - KEFFI	SH	132	1	1	41	1983	
KATAMPE - KUBWA	SH	132	2	1	7	1981	
KATAMPE - APO	SH	132	2	1	15	2011	
KATAMPE - CENTRAL AREA	SH	132	2	1	6	2005	
KONTAGORA - TEGINA	SH	132	1	1	90	1990	
KONTAGORA - YELWA	SH	132	1	1	88	1990	
KUBWA - SULEJA	SH	132	2	1	40	1981	
MINNA - SULEJA	SH	132	2	1	167	1981	
MINNA - SULEJA	SH	132	2	1	99	1981	
SHIRORO - TEGINA	SH	132	1	1	65	1990	
SHIRORO - MINNA	SH	132	2	1	68	1990	
SOKOTO - TMAFARA	SH	132	1	1	125	1990	
TMAFARA - GUSAU	SH	132	1	1	85	1988	

Existing TCN Substations

Substation name	Geog'cal area	Voltage	No. of circuits		No. of transformers		Total number of reactors/capacitors			Year of commission
			330kV	132kV	330/132 or 330/132/lower	132/lower	330kV React	132kV Cap	33kV Cap	
Aladja	BE	330	2							1983
Jebba GS	SH	330	8							1984
Kainji	SH	330	8							1969
Ogijo	LA	330	4							2013
Okpai	BE	330	2							2005
Sapele	BE	330	12							1983
Alaoji	PH	330/132	3	8	3		1			1978
Egbin	LA	330/132	12	2	2					1983
Ikeja-West	LA	330/132	9	12	4		2			1977
Afam	PH	330/132/33	13	4	1	1				1978
Aja	LA	330/132/33	4		2	2				1984
Ajaokuta	BE	330/132/33	2	1	3	1	1			1981
Akangba	LA	330/132/33	2	3	6	3				1968
Alagbon	LA	330/132/33	2	2		2				1980
Ayede	OS	330/132/33	2	4	3	3			2	1977
Benin	BE	330/132/33	14	3	2	4	1			1977
Birnin-Kebbi	SH	330/132/33	1	2	2	2				1968
Gombe	BA	330/132/33	3	4	2	2	1			1979
Jalingo	BA	330/132/33	1			2				2009
Jebba TS	SH	330/132/33	9		1	1	2			1968
Jos	BA	330/132/33	2	5	1	2				1979
Katampe	SH	330/132/33	2	6	2	2				2002
Kumbotso (Kano)	KA	330/132/33	1	7	4	4	1		1	1977
Mando (Kaduna)	KA	330/132/33	4	3	3	6				1981

Substation name	Geog'cal area	Voltage	No. of circuits		No. of transformers		Total number of reactors/capacitors			Year of commission
			330kV	132kV	330/132 or 330/132/lower	132/lower	330kV React	132kV Cap	33kV Cap	
New Haven (Enugu)	EN	330/132/33	1	4	2	3	1			1981
Onitsha	EN	330/132/33	8	4	4	4	1			1968
Oshogbo	OS	330/132/33	6	4	3	3	1			1974
Shiroro	SH	330/132/33	10	3	2	1				1974
Ughelli (Delta)	BE	330/132/33	8	3		2				1979
Yola	BA	330/132/33	2	3	2	2	3			1978
Aba Town	PH	132/33		3		5				1961
Abakaliki	EN	132/33		1		2				2000
Abeokuta	LA	132/33		1		3			2	1979
Ado-Ekiti	OS	132/33		1		2				2001
Agbara	LA	132/33		4		3			1	1982
Ahoada	PH	132/33		6		2				2001
Akoka	LA	132/33		4		2				1987
Akure	OS	132/33		2		3			1	1964
Akwanga	SH	132/33		1		2			1	1996
Alausa	LA	132/33		2		2				1982
Alimosho	LA	132/33		4		3				1986
Amukpe	BE	132/33		2		1			1	2007
Amuwo-Odofin	LA	132/33		4		3				1978
Apapa Road	LA	132/33		2		4				1978
Apir	EN	132/33		1		1			1	2001
Apo	SH	132/33		3		3				1981
Awka	EN	132/33		2		2			1	2002
Azare	KA	132/33		2		2				2007
Bauchi	BA	132/33		2		2				1995
Bida	SH	132/33		1		2				1983

Substation name	Geog'cal area	Voltage	No. of circuits		No. of transformers		Total number of reactors/capacitors			Year of commission
			330kV	132kV	330/132 or 330/132/lower	132/lower	330kV React	132kV Cap	33kV Cap	
Biu	BA	132/33		2		2				1976
Calabar	PH	132/33		1		3				1981
Central Area	SH	132/33		2		3				2003
Dakata	KA	132/33		2		3			1	1978
Dan-Agundi	KA	132/33		1		2			1	1999
Domboa	BA	132/33		2		1				1986
Dutse	KA	132/33		4		2				2007
Effurun	BE	132/33		1		3			1	1975
Ejigbo	LA	132/33		4		3				1978
Eket	PH	132/33		1		2				1978
Funtua	KA	132/33		2		3				1975
GCM	EN	132/33		1		1				1982
Geregu T S	BE	132/33		2		1				2002
Gusau	KA	132/33		2		2				1978
Hadejia	KA	132/33		1		2			1	1975
Ibadan North	OS	132/33		2		2				1997
Ife	OS	132/33		3		2			1	1979
Ijebu-Ode	OS	132/33		1		2			1	1979
Ijora	LA	132/33		3		4				1965
Ikorodu	LA	132/33		3		3			2	1999
Ilesha	OS	132/33		1		2				1996
Ilorin	OS	132/33		1		2			1	1982
Ilupeju	LA	132/33		4		4			1	1974
Irrua	BE	132/33		2		2			1	2002
Iseyin	OS	132/33		1		1			1	1982
Isolo	LA	132/33		1		3				1974

Substation name	Geog'cal area	Voltage	No. of circuits		No. of transformers		Total number of reactors/capacitors			Year of commission
			330kV	132kV	330/132 or 330/132/lower	132/lower	330kV React	132kV Cap	33kV Cap	
Itire	LA	132/33		2		2				1986
Itu	PH	132/33		2		1				2010
Jericho	OS	132/33		2		2				1980
Kaduna town	KA	132/33		2		5			2	1975
Kankia	KA	132/33		2		2				1978
Karu	SH	132/33		2	3	2	1			2011
Katsina	KA	132/33		2		3				2001
Keffi	SH	132/33		2		1				2008
Kontogora	SH	132/33		2		2				1974
Kubuwa	SH	132/33		4		3			1	2011
Maiduguri	BA	132/33		1		3				1976
Maiduguri	BA	132/33				3				1976
Mary Land	LA	132/33		2		3				1986
Minna	SH	132/33		7	2	1				1980
Nkalagu	EN	132/33		2		2				1978
Nsukka	EN	132/33		1		2				1975
Offa	OS	132/33		3		1				1987
Ogba	LA	132/33		5		5				1978
Oji River	EN	132/33		2		2				1975
Ojo	LA	132/33		4		4			2	1965
Okene	BE	132/33		2		2			1	1987
Omuaran	OS	132/33		1		2				1986
Ondo	OS	132/33		2		2				1979
Otta	LA	132/33		4		4				1996
Oturpko	EN	132/33		2		2				1978
Owerri	PH	132/33		6		3				1999

Substation name	Geog'cal area	Voltage	No. of circuits		No. of transformers		Total number of reactors/capacitors			Year of commission
			330kV	132kV	330/132 or 330/132/lower	132/lower	330kV React	132kV Cap	33kV Cap	
Oworonsoki	LA	132/33		3		2				1979
Papalanto	LA	132/33		2		3				1972
PH MAINS	PH	132/33		8		3				1999
PH Town	PH	132/33		2		4				1982
Potiskum	BA	132/33		1		2				1987
Savanah	BA	132/33		2		1				1974
Shagamu	OS	132/33		3		2				1979
Shagamu Cement	LA	132/33		2		2			1	1979
Sokoto	SH	132/33		2		2				1979
Suleja	SH	132/33		6		1				1980
T/Mafara	KA	132/33		2		1				2001
Tegina	SH	132/33		2		1				1995
Ukpilla	BE	132/33		2		1				1975
Uyo	PH	132/33		2		2			1	1995
Yandev	EN	132/33		2		4			1	1975
Yenagoa	PH	132/33		4		2				2001
Zaria	KA	132/33		3		2			1	1998

Existing TCN Transformers

Substation	Geographical area	Voltage	Capacity (MVA)	Year manufact-ured	Loading
Bauchi	BA	132/33	40	1995	67%
Bauchi	BA	132/33	40	1999	58%
Biu	BA	132/33	15	1976	49%
Biu	BA	132/33	30	1987	49%
Domboa	BA	132/33	30	1986	57%
Gombe	BA	132/33	40	1979	60%
Gombe	BA	330/132/33	150	1981	46%
Gombe	BA	330/132/33	150	1999	46%
Gombe	BA	132/33	60	2009	77%
Jalingo	BA	132/33	30	2009	12%
Jalingo	BA	132/33	30	2009	25%
Jos	BA	132/33	60	1979	75%
Jos	BA	330/132/33	150	1981	71%
Jos	BA	132/33	60	1983	63%
Maiduguri	BA	132/33/11	15	1976	50%
Maiduguri	BA	132/33/11	45	1982	67%
Maiduguri	BA	132/33/11	45	1982	29%
Pokiskum	BA	132/33	30	1987	53%
Pokiskum	BA	132/33	30	1988	75%
Savanah	BA	132/33	15	1974	50%
Yola	BA	132/33	30	1982	85%
Yola	BA	132/33	30	1982	77%
Yola	BA	330/132	150	2002	39%
Yola	BA	330/132	150	2002	39%
Ajaokuta	BE	330/132/33	162	1981	71%
Ajaokuta	BE	330/132/33	162	1981	71%
Ajaokuta	BE	330/132/33	162	1981	71%
Ajaokuta	BE	132/33	60	2009	78%
Amukpe	BE	132/33	30	2007	78%
Benin	BE	330/132/33	150	1977	85%
Benin	BE	330/132/33	150	1977	85%
Benin	BE	132/33	60	1986	92%
Benin	BE	132/33	60	1996	85%
Benin	BE	132/33	60	2000	96%
Benin	BE	132/33	60	2009	90%
Effurun	BE	132/33	30	1975	61%
Effurun	BE	132/33	60	1979	86%
Effurun	BE	132/33	60	2002	97%
Geregu T S	BE	132/33	30	2002	50%
Irrua	BE	132/33	60	2002	55%
Irrua	BE	132/33	30	2002	95%

Substation	Geographical area	Voltage	Capacity (MVA)	Year manufact-ured	Loading
Okene	BE	132/33	40	1987	96%
Okene	BE	132/33	40	1987	92%
Ughelli	BE	132/33	60	1979	93%
Ughelli	BE	132/33	30	1979	94%
Ukpilla	BE	132/33	15	1975	90%
Abakaliki	EN	132/33	60	2000	89%
Abakaliki	EN	132/33	30	2002	93%
Awka	EN	132/33	30	2002	90%
Awka	EN	132/33	30	2008	87%
Enugu	EN	132/33	60	2009	0%
GCM	EN	132/33	15	1982	61%
New Haven	EN	330/132	150	1981	97%
New Haven	EN	330/132	150	1981	97%
New Heaven	EN	132/33	30	1981	59%
New Heaven	EN	132/33	30	1981	109%
New Heaven	EN	132/33	60	2001	93%
New Heaven	EN	132/33	60	2001	68%
Nkalagu	EN	132/33	30	1978	75%
Nkalagu	EN	132/33	30	1978	7%
Nsukka	EN	132/33	7.5	1978	90%
Nsukka	EN	132/33	7.5	1978	90%
Oji River	EN	132/33	30	2002	52%
Onitsha	EN	330/132	90	1968	125%
Onitsha	EN	330/132	90	1974	104%
Onitsha	EN	132/33	15	1978	61%
Onitsha	EN	132/33	60	1979	101%
Onitsha	EN	330/132	150	2002	98%
Onitsha	EN	330/132	150	2002	84%
Onitsha	EN	132/33	45	2002	84%
Onitsha	EN	132/33	60	2002	68%
Otukpo	EN	132/33	7.5	1978	93%
Otukpo	EN	132/33	30	2002	93%
Yandev	EN	132/33	15	1975	73%
Yandev	EN	132/33	15	1975	73%
Yandev	EN	132/33	45	1979	73%
Yandev	EN	132/33	40	2001	73%
Azare	KA	132/33	30	2007	35%
Azare	KA	132/33	30	2007	29%
Dakata	KA	132/33	60	1978	40%
Dakata	KA	132/33	60	1994	67%
Dakata	KA	132/33	30	1996	71%
Dan-Agundi	KA	132/33	60	1999	63%

Substation	Geographical area	Voltage	Capacity (MVA)	Year manufact-ured	Loading
Dan-Agundi	KA	132/33	60	2001	78%
Dutse	KA	132/33	30	2007	57%
Dutse	KA	132/33	30	2007	57%
Funtua	KA	132/11	7.5	1975	100%
Funtua	KA	132/11	7.5	1975	93%
Funtua	KA	132/33	30	2001	60%
Gusau	KA	132/33	30	1978	43%
Gusau	KA	132/33	30	1978	74%
Hadejia	KA	132/33	7.5	1975	75%
Hadejia	KA	132/33	15	1978	83%
Kaduna town	KA	132/33	60	1975	63%
Kaduna town	KA	132/33	30	1975	97%
Kaduna town	KA	132/33	30	1987	97%
Kaduna town	KA	132/33	60	2002	74%
Kaduna town	KA	132/33	15	1978	93%
Kankia	KA	132/33	7.5	1978	45%
Kankia	KA	132/33	30	1999	45%
Katsina	KA	132/33	30	2001	38%
Katsina	KA	132/33	30	2001	49%
Katsina	KA	132/33	60	2009	33%
Kumbotso	KA	330/132	150	1977	58%
Kumbotso	KA	132/33	30	1987	75%
Kumbotso	KA	132/33	40	1996	75%
Kumbotso	KA	132/33	30	1996	99%
Kumbotso	KA	330/132	150	2008	58%
Kumbotso	KA	330/132	150	2009	50%
Kumbotso	KA	132/33	60	2009	102%
Kumbotso	KA	330/132	150	2011	92%
Mando	KA	330/132	150	1981	80%
Mando	KA	132/33	30	2002	79%
Mando	KA	132/33	60	2002	77%
Mando	KA	330/132	150	2008	80%
Mando	KA	330/132	150	2009	71%
Mando	KA	132/33	60	2009	70%
Mando	KA	132/33	60	2010	6%
Mando	KA	330/132	60	2010	80%
Mando	KA	330/132	90	2010	80%
T/Mafara	KA	132/33	30	2001	39%
Zaria	KA	132/33	40	1998	98%
Zaria	KA	132/33/11	60	2009	30%
Abeokuta	LA	132/33	30	1979	87%
Abeokuta	LA	132/33	30	1979	94%

Substation	Geographical area	Voltage	Capacity (MVA)	Year manufact-ured	Loading
Abeokuta	LA	132/33	30	2000	98%
African Foundry	LA	132/33	80	2011	30%
Agbara	LA	132/33	30	1982	65%
Agbara	LA	132/33	30	1982	65%
Agbara	LA	132/33	60	2012	54%
Aja	LA	132/33	60	1984	100%
Aja	LA	330/132	150	1999	98%
Aja	LA	330/132	150	2002	100%
Aja	LA	132/33	60	2002	100%
Akangba	LA	330/132	90	1968	67%
Akangba	LA	330/132	90	1968	67%
Akangba	LA	330/132	90	1974	67%
Akangba	LA	330/132	90	1974	67%
Akangba	LA	330/132	150	1981	65%
Akangba	LA	132/33	60	1981	63%
Akangba	LA	132/33	60	1994	69%
Akangba	LA	132/33	60	2009	46%
Akangba	LA	330/132	150	2010	66%
Akoka	LA	132/33	45	1987	125%
Akoka	LA	132/33	40	1987	66%
Akoka	LA	132/33	15	1987	108%
Alagbon	LA	132/33	60	1980	95%
Alagbon	LA	132/33	60	1980	95%
Alausa	LA	132/33	45	1982	117%
Alausa	LA	132/33	60	1999	86%
Alausa	LA	132/33	30	1999	61%
Alimosho	LA	132/33	30	1986	80%
Alimosho	LA	132/33	30	1986	88%
Alimosho	LA	132/33	60	1996	94%
Amuwo-Odofin	LA	132/33	60	1978	50%
Amuwo-Odofin	LA	132/33	30	1987	83%
Amuwo-Odofin	LA	132/33	40	1987	66%
Apapa Road	LA	132/33	30	1978	96%
Apapa Road	LA	132/33	30	1978	108%
Apapa Road	LA	132/33	15	1978	108%
Egbin	LA	330/132	150	1983	57%
Egbin	LA	330/132	150	1984	57%
Ejigbo	LA	132/33	30	1978	102%
Ejigbo	LA	132/33	30	1978	102%
Ejigbo	LA	132/33	30	2008	83%
Ijora	LA	132/33	30	1965	72%
Ijora	LA	132/33	30	1965	72%

Substation	Geographical area	Voltage	Capacity (MVA)	Year manufact-ured	Loading
Ijora	LA	132/33	30	1965	92%
Ijora	LA	132/33	30	1979	72%
Ikeja-West	LA	330/132	150	1977	100%
Ikeja-West	LA	330/132	150	1977	100%
Ikeja-West	LA	330/132	150	1977	100%
Ikeja-West	LA	330/132	150	1977	100%
Ikeja-West	LA	330/132	150	2001	63%
Ikorodu	LA	132/33	60	1999	83%
Ikorodu	LA	132/33	60	1999	81%
Ikorodu	LA	132/33	60	1999	79%
Ilupeju	LA	132/11	15	1974	79%
Ilupeju	LA	132/11	15	1978	79%
Ilupeju	LA	132/33	30	1979	83%
Ilupeju	LA	132/11	30	1980	54%
Isolo	LA	132/33/11	60	1974	65%
Isolo	LA	132/33/11	30	1977	35%
Isolo	LA	132/33/11	30	1984	78%
Isolo	LA	132/33/11	15	1984	75%
Itire	LA	132/33	30	1995	86%
Itire	LA	132/33	40	1995	87%
MaryLand	LA	132/33	30	1986	69%
MaryLand	LA	132/33	30	1987	63%
MaryLand	LA	132/33	60	1987	69%
Ogba	LA	132/33	30	1978	65%
Ogba	LA	132/11	20	1978	56%
Ogba	LA	132/33	40	1986	67%
Ogba	LA	132/33	60	1987	88%
Ogba	LA	132/33	60	1994	85%
Ojo	LA	132/33	30	1965	25%
Ojo	LA	132/33	30	2001	25%
Ojo	LA	132/33	60	2009	25%
Ojo	LA	132/33	60	2009	85%
Otta	LA	132/33	30	1996	92%
Otta	LA	132/33	60	2000	58%
Otta	LA	132/33	40	2001	58%
Otta	LA	132/33	30	2011	100%
Oworonsoki	LA	132/33	60	1979	63%
Oworonsoki	LA	132/33	30	1980	63%
Papalanto	LA	132/33	15	1972	110%
Papalanto	LA	132/33	15	1972	110%
Papalanto	LA	132/33	30	1999	98%
Shagamu Cement	LA	132/11	15	1979	58%

Substation	Geographical area	Voltage	Capacity (MVA)	Year manufact-ured	Loading
Shagamu Cement	LA	132/11	15	1979	0%
Ado-Ekiti	OS	132/33	40	2001	60%
Ado-Ekiti	OS	132/33	40	2001	60%
Akure	OS	132/33	15	1964	73%
Akure	OS	132/33	30	1978	51%
Akure	OS	132/33	60	2000	51%
Ayede	OS	330/132	150	1977	79%
Ayede	OS	330/132	150	1977	82%
Ayede	OS	132/33	30	1982	0%
Ayede	OS	132/33	60	1999	54%
Ayede	OS	330/132	150	2008	0%
Ayede	OS	132/33	60	2010	44%
Ganmo	OS	330/132	150	2006	31%
Ganmo	OS	330/132	150	2006	47%
Ganmo	OS	132/33	60	2007	78%
Ganmo	OS	132/33	60	2007	29%
Ibadan North	OS	132/33	30	1997	31%
Ibadan North	OS	132/33	60	1997	83%
Ife	OS	132/33	30	1979	54%
Ife	OS	132/33	30	1979	87%
Ijebu-Ode	OS	132/33	30	1979	75%
Ijebu-Ode	OS	132/33	30	1979	91%
Ilesa	OS	132/33	40	1996	35%
Ilesa	OS	132/33	40	1996	26%
Ilorin	OS	132/33	30	1982	67%
Ilorin	OS	132/33	60	1987	72%
Iseyin	OS	132/33	45	1982	76%
Jericho	OS	132/33	45	1980	82%
Jericho	OS	132/33	40	2000	36%
Offa	OS	132/33	30	1987	75%
Omuaran	OS	132/33	30	1986	47%
Omuaran	OS	132/33	30	2003	55%
Ondo	OS	132/33	30	1979	51%
Ondo	OS	132/33	30	1979	55%
Oshogbo	OS	330/132	90	1974	94%
Oshogbo	OS	132/33	30	1978	94%
Oshogbo	OS	132/33	60	1982	70%
Oshogbo	OS	330/132	150	2004	94%
Oshogbo	OS	330/132	150	2008	94%
Oshogbo	OS	132/33	60	2008	70%
Shagamu	OS	132/33	30	1979	90%
Shagamu	OS	132/33	30	1979	59%

Substation	Geographical area	Voltage	Capacity (MVA)	Year manufact-ured	Loading
Aba Town	PH	132/6.6	7.5	1961	68%
Aba Town	PH	132/33	30	1976	99%
Aba Town	PH	132/33/11	30	1982	99%
Aba Town	PH	132/33	30	1995	99%
Aba Town	PH	132/33	60	1999	99%
Afam	PH	330/132	162	1978	58%
Afam	PH	132/33	45	1979	76%
Afam	PH	132/33	64	1979	40%
Afam IPP	PH	330/132	64	2011	40%
Ahoada	PH	132/33	40	2001	52%
Ahoada	PH	132/33	40	2001	66%
Alaoji	PH	330/132	150	1978	80%
Alaoji	PH	330/132	150	1978	80%
Alaoji	PH	330/132	150	2004	80%
Calabar	PH	132/33	60	1981	72%
Calabar	PH	132/33	60	1996	73%
Eket	PH	132/33	45	1978	51%
Eket	PH	132/33	60	1999	32%
Itu	PH	132/33	60	2010	40%
Owerri	PH	132/33	40	1999	80%
Owerri	PH	132/33	60	2008	93%
Owerri	PH	132/33/11	60	2011	100%
PH MAINS	PH	132/33	60	1999	97%
PH MAINS	PH	132/33/11	60	2008	39%
PH MAINS	PH	132/33/11	60	2010	99%
PH Town	PH	132/11	45	1982	40%
PH Town	PH	132/33	30	1996	86%
PH Town	PH	132/33	30	1996	74%
PH Town	PH	132/33	60	2009	90%
Uyo	PH	132/33	40	1995	33%
Uyo	PH	132/33	40	1995	31%
Yenagoa	PH	132/33	40	2001	74%
Yenagoa	PH	132/33	40	2001	73%
Apo	SH	132/33	30	1981	72%
Apo	SH	132/33	30	1981	72%
Apo	SH	132/33	60	2009	99%
Akwanga	SH	132/33	40	1996	61%
Akwanga	SH	132/33	40	2011	52%
Bida	SH	132/33	30	1983	80%
Bida	SH	132/33	30	1992	68%
Birnin-Kebbi	SH	330/132/33	90	1968	106%
Birnin-Kebbi	SH	330/132/33	90	1970	101%

Substation	Geographical area	Voltage	Capacity (MVA)	Year manufact-ured	Loading
Birnin-Kebbi	SH	132/33	30	1987	97%
Birnin-Kebbi	SH	132/33	60	2009	29%
Central Area	SH	132/33	60	2003	54%
Central Area	SH	132/33	60	2003	54%
Central Area	SH	132/33	60	2012	54%
Jebba	SH	330/132/33	80	1968	34%
Jebba	SH	132/33	30	1987	88%
Karu	SH	132/33	45	2011	31%
Karu	SH	132/33	45	2011	67%
Katampe	SH	330/132/33	150	2002	46%
Katampe	SH	330/132/33	150	2002	99%
Katampe	SH	132/33	60	2002	99%
Katampe	SH	132/33	60	2002	98%
Katampe	SH	330/132/33	150	2010	98%
Keffi	SH	132/33	30	2008	85%
Kontogora	SH	132/33	30	1974	88%
Kubuwa	SH	132/33	60	2011	68%
Kubuwa	SH	132/33	60	2011	82%
Minna	SH	132/33	30	1980	73%
Minna	SH	132/33	30	1980	73%
Minna	SH	132/33	60	2009	68%
Shiroro	SH	330/132/33	150	1981	52%
Shiroro	SH	330/132/33	150	1981	28%
Shiroro	SH	132/33	30	1974	54%
Sokoto	SH	132/33	30	1979	70%
Sokoto	SH	132/33	30	1987	88%
Sokoto	SH	132/33	30	1987	87%
Suleja	SH	132/11	30	1980	100%
Suleja	SH	132/33	7.5	1996	95%
Tegina	SH	132/33	30	1995	61%

Annex 2: NIPP ASSETS

Existing NIPP Transmission line

Line Name	Voltage (V)	Length (km)	No. of circuits	No. of Conductors	Geographical area	Commission date
JOS - MAKURDI	330	286	2	2	BA	2013
AJAOKUTA - GEREGU PS	330	10	2	2	BE	2010
AJAOKUTA - LOKOJA	330	47.39	2	2	BE	2013
BENINNORTH - EYEAN	330	3	2	2	BE	2013
MAKURDI - UGWUAJI	330	264	2	2	EN	2014
NHAVEN - UGWUAJI	330	7	2	2	EN	2014
ONITSHA - OWERRI	330	88	2	2	EN	2016
ABASI - IKOT-EKPENE	330	78	2	2	PH	2014
AFAMIV - IKOT-EKPENE	330	81	2	2	PH	2014
AFAMIV - ONNIE	330	40	2	2	PH	2016
ALAOJI - IKOT-EKPENE	330	54.5	2	2	PH	2014
ALAOJI - OWERRI	330	60	2	2	PH	2014
CALABAR - CALABAR	330	48	2	2	PH	2013
IKOT-EKPENE - CALABAR	330	22	2	2	PH	2014
OMOKU - EGBEMA	330	67	2	2	PH	2014
OWERRI - EGBEMA	330	67	2	2	PH	2014
UGWUAJI - IKOT-EKPENE	330	162	2	2	PH	2014
UGWUAJI - IKOT-EKPENE	330	162	2	2	PH	2014
EASTMAIN - GWAGWALADA	330	42	2	2	SH	2013
GWAGWALADA - LOKOJA	330	174.6	2	2	SH	2013
KATAMPE-SHIRORO LINE - GWAGWALADA	330	40	2	2	SH	2013
Oke-Aro - Alausa	132	30	2	1	LA	2014
Oke-Aro - Maryland	132	35	2	1	LA	2015
Agbor - Asaba	132	51	2	1	BE	2013
Nnewi - Ihiala - Orlu	132	43.6	2	1	EN	2013
Otta - Ogba Junction - Papalanto	132	35	2	1	LA	2013
Papalanto - Old Abeokuta	132	55	2	1	LA	2013
Old Abeokuta - New Abeokuta	132	35	2	1	LA	2013
Lekki - Aja	132	35	2	1	LA	2013
Kukwaba - Apo	132	24	2	1	SH	2013
Onne - Transamadi	132	10	2	1	PH	2013
Ihovbor - Okada	132	60	2	1	BE	2013
Abakiliki - Ikom	132	95	2	1	PH	2013
Nkalagu - Abakiliki	132	38	2	1	PH	2013
New Heaven North - Nsukka	132	70.6	2	1	EN	2013

Existing NIPP Substations

Substation Name	Voltage	Circuits			330/132 transformers		132/33 transformers		Geographical area	Commission date
		No. of 330kV	No. of 132kV	No. of 33kV	No. of 150MVA	No. of 300MVA	No. of 60MVA	No of 100MVA		
330/132KV Oloronsogo SS (New)	330	8	0	0	0	0	0	0	LA	2008
330KV Ajaokuta SS (Line Bay Ext.) - guesstimated	330	2	0	0	0	0	0	0	BE	2010
Geregu PS	330	8	0	0	0	0	0	0	BE	2010
330KV Afam SS (Ext.)	330	2	0	0	0	0	0	0	PH	2013
330KV Afam SS (Line Bay Ext.)	330	2	0	0	0	0	0	0	PH	2013
330KV Ajaokuta SS (Line Bay Ext.)	330	2	0	0	0	0	0	0	BE	2013
330KV Ikot Ekpene SS	330	12	0	0	0	0	0	0	PH	2013
330KV Onitsha SS (Line bay ext.)	330	2	0	0	0	0	0	0	EN	2013
330KV Alaoji SS (Line bay ext.)	330	4	0	0	0	0	0	0	PH	2014
Egbema	330	4	0	0	0	0	0	0	PH	2014
330/132KV Katampe SS (Ext.)	330/132	0	0	0	1	0	0	0	SH	2009
330/132KV Omotosho SS (New)	330/132	10	0	0	3	0	0	0	OS	2009
330/132KV New Haven SS (Ext.)	330/132	2	2	0	0	0	0	0	EN	2013
330/132KV Jos SS (Ext)	330/132	2	0	0	1	0	0	0	BA	2013
330/132/33KV Ganmo SS (New)	330/132/33	2	2	6	2	0	2	0	OS	2009
330/132KV Calabar SS (New)	330/132/33	2	4	9	2	0	3	0	PH	2010
330/132/33KV Mando SS (Ext.)	330/132/33	0	0	0	1	0	1	0	KA	2011

Substation Name	Voltage	Circuits			330/132 transformers		132/33 transformers		Geographical area	Commission date
		No. of 330kV	No. of 132kV	No. of 33kV	No. of 150MVA	No. of 300MVA	No. of 60MVA	No of 100MVA		
330/132/33KV Makurdi SS (New)	330/132/33	4	1	6	1	0	1	0	EN	2013
330/132/33KV Alagbon G.I.S. SS (New and Ext.)	330/132/33	2	0	6	0	1	2	0	LA	2013
330/132/33KV Gwagwalada SS (New)	330/132/33	6	2	6	2	0	2	0	SH	2013
330/132/33KV Ikot Abasi SS (New)	330/132/33	2	4	0	3	0	0	0	PH	2013
330/132/33KV Lekki G.I.S. SS (New)	330/132/33	4	2	6	0	1	0	1	LA	2013
330/132/33KV Lokoja SS (New)	330/132/33	4	2	3	1	0	1	0	BE	2013
330/132/33KV Oke Aro SS (New)	330/132/33	4	4	6	2	0	2	0	LA	2013
330/132/33KV Omoku SS (Supervised by DECON for Steag)	330/132/33	2	2	6	2	0	2	0	PH	2013
330/132/33KV Onne SS (New)	330/132/33	2	2	6	2	0	2	0	PH	2013
330/132/33KV Owerri SS (New)	330/132/33	6	2	6	2	0	2	0	PH	2013
330/132KV Aja G.I.S. SS (Ext.)	330/132/33	2	2	0	1	0	0	2	LA	2013
330/132KV Asaba SS (New)	330/132/33	2	2	6	1	0	2	0	BE	2013
330/132KV Ihovbor SS (New) - Benin North	330/132/33	6	4	6	2	0	2	0	BE	2013
330KV Ugwuaji SS Extension (New)	330/132/33	8	0	3	1	0	1	0	EN	2013
East main	330/132/33	2	2	0	2	0	0	0	SH	2013
330kV Ihiala 330/132kV substation New	330/132/33	4	4	0	1	0	1	0	EN	2014
Uyo SS (Replacement of Transformer)	132/33	0	0	0	0	0	2	0	PH	2013
Itu SS (Replacement of Transformer)	132/33	0	0	0	0	0	1	0	PH	2013

Substation Name	Voltage	Circuits			330/132 transformers		132/33 transformers		Geographical area	Commission date
		No. of 330kV	No. of 132kV	No. of 33kV	No. of 150MVA	No. of 300MVA	No. of 60MVA	No of 100MVA		
Alausa SS (Line Bay Extension)	132/33	0	2	0	0	0	0	0	LA	2013
Awka Substation	132/33	0	2	6	0	0	2	0	EN	2013
Agbor substation (New)	132/33	0	2	6	0	0	2	0	BE	2013
Nkalagu substation	132/33	0	0	0	0	0	1	0	EN	2013
Ayede substation	132/33	0	0	0	0	0	1	0	LA	2009
Central Area substation Extension	132/33	0	0	0	0	0	1	0	SH	2011
Kumbotso substation Extension	132/33	0	0	0	0	0	1	0	KA	2011
Agbara substation Extension	132/33	0	0	0	0	0	1	0	LA	2012
Ojo substation Extension	132/33	0	2	0	0	0	2	0	LA	2012
Oworonsoki substation Extension	132/33	0	2	0	0	0	2	0	LA	2012
New Abeokuta Substation (New)	132/33	0	2	6	0	0	2	0	LA	2013
Old Abeokuta Substaition	132/33	0	2	0	0	0	0	0	LA	2013
Otta Substation Extension	132/33	0	2	0	0	0	0	0	LA	2013
Apo Substation Extention	132/33	0	2	3	0	0	0	1	SH	2013
Kukwaba Substation Extention	132/33	0	4	0	0	0	0	0	SH	2013
TransAmadi Susbstation Extention	132/33	0	2	0	0	0	0	0	PH	2013
Okada Substation (New)	132/33	0	2	6	0	0	2	0	BE	2013
Ikom substation (New)	132/33	0	4	3	0	0	1	0	PH	2013

Substation Name	Voltage	Circuits			330/132 transformers		132/33 transformers		Geographical area	Commission date
		No. of 330kV	No. of 132kV	No. of 33kV	No. of 150MVA	No. of 300MVA	No. of 60MVA	No of 100MVA		
Abakiliki Substation (Extension)	132/33	0	4	0	0	0	0	0	EN	2013
Nkalagu substation (Extension)	132/33	0	2	0	0	0	0	0	EN	2013
Obudu substation (new)	132/33	0	4	3	0	0	1	0	EN	2013
Nsukka Substation (new)	132/33	0	2	3	0	0	1	0	EN	2013
Calabar EPZ Substation	132/33	0	2	6	0	0	2	0	PH	2013
Orlu Substation (new)	132/33	0	2	6	0	0	2	0	PH	2013

Annex 3: Expected generation in 2026

Power station	Location	Fuel type	Classification	Capacity by 2026	Loading in load flow	Commission year
Kainji	Niger	Hydro	CONS	760	760	1968
Sapele	Delta	Thermal	SC	980	705	1981
Jebba	Niger	Hydro	CONS	540	540	1985
Egbin	Lagos	Thermal	SC	1320	1200	1986
Shiroro	Niger	Hydro	CONS	600	600	1990
Delta	Delta	Thermal	SC	1074	710	1990
AES	Lagos	Thermal	IPP	270	270	2001
Omotoso Phase 1	Ondo	Thermal	SC	304	0	2005
Omoku Phase 1	Rivers	Thermal	NIPP	225	225	2005
Geregu	Kogi	Thermal	SC	414	0	2007
Oloronsogo Phase 1	Ogun	Thermal	SC	304	0	2007
Afam IV&V	Rivers	Thermal	SC	1122	1122	2010
Oloronsogo 2	Ogun	Thermal	NIPP	675	675	2012
Sapele 2	Delta	Thermal	NIPP	450	0	2012
Geregu phase II	Kogi	Thermal	NIPP	434	0	2012
Omotoso phase II	Ondo	Thermal	NIPP	450	0	2012
Trans-Amadi	Rivers	Thermal	NIPP	300	0	2012
Alaoji	Abia	Thermal	NIPP	960	960	2013
Ihovbor	Edo	Thermal	NIPP	450	450	2013
Ibom Power	Akwa Ibom	Thermal	IPP	170	170	2013
Calabar	Cross Rivers	Thermal	NIPP	562	562	2014
Omoku Phase 2	Rivers	Thermal	NIPP	120	0	2014
Rivers Afam II	Rivers	Thermal	IPP	320	320	2014
Obajana	Kogi	Thermal	IPP	150	150	2014
ENCON	Rivers	Thermal	IPP	250	0	2017

Power station	Location	Fuel type	Classification	Capacity by 2026	Loading in load flow	Commission year
Geometric - Aba	Abia	Thermal	IPP	540	540	2017
Gurara	Niger	Hydro	IPP	0	0	After 2026
Gbarain	Bayelsa	Thermal	NIPP	225	225	2018
Egbema	Imo state	Thermal	NIPP	337	337	2018
WEMPCO	Ogun	Thermal	IPP	0	0	After 2026
Notore	Rivers	Thermal	IPP	525	25	2018
Azura	Edo	Thermal	IPP	670	450	2018
Kaduna	Kaduna	Thermal	IPP	0	0	After 2026
Total Fina	Rivers	Thermal	IOC	470	470	2018
Mabon	Gombe	Hydro	IPP	0	0	After 2026
MBH Power	Lagos	Thermal	IPP	0	0	After 2026
SuperTek	Rivers	Thermal	IPP	0	0	After 2026
Lagos GVT Power	Lagos	Thermal	IPP	140	140	2019
Chevron	Rivers	Thermal	IOC	0	0	After 2026
Shell	Rivers	Thermal	IOC	0	0	After 2026
Mobil	Akwa Ibom	Thermal	IOC	500	500	2019
Agip - I	Rivers	Thermal	IOC	470	470	2020
Zungeru	Niger	Hydro	New	700	700	2021
Agip - II	Rivers	Thermal	IOC	0	0	After 2026
Mambilla	Taraba	Hydro	New	3000	2200	2024

Annex 4: New Assets

New 330kV lines required

Line Name	Voltage (V)	Length (km)	No. of circuits	No. of conductors	TCN region	Commission date
LOKOJA - OBAJANA	330	45.4	2	2	BE	2014
OSOGBO - AKURE	330	200	2	2	OS	2015
AKURE - BENIN NORTH	330	60	2	2	SH	2015
KADUNA - KANO	330	230	2	2	KA	2016
KADUNA - JOS	330	196	2	2	KA	2016
AJA - EPE	330	50	2	2	LA	2016
EPE - OMOTOSO	330	85	2	2	LA	2016
IKEJAW - OLORUNSOGO	330	30	1	2	LA	2016
OMOTOSO - OGIJO	330	175	2	2	LA	2017
GOMBE - JOS	330	264	2	2	BA	2018
OLORUNSOGO - AGBARA	330	30	2	2	LA	2018
SAKETE - AGBARA	330	86	2	2	LA	2018
AKANGBA - AGBARA	330	10	2	2	LA	2018
BKEBBI - KAINJI G.S.	330	310	2	2	SH	2018
DELTA IV - BENIN NORTH	330	95	1	2	BE	2019
DELTA IV - ONNIE	330	175	2	2	PH	2019
APONEW - EASTMAIN	330	20	2	2	SH	2019
APONEW - MAKURDI	330	140	2	2	SH	2019
Delta-Benin extension to Benin North	330	27	1	2	BE	2019
GOMBE - DAMATURU	330	180	2	2	BA	2020
KANO - KATSINA	330	180	2	2	KA	2020
OLORUNSOGO - OGIJO	330	40	2	2	LA	2020
BKEBBI - SOKOTO	330	130	2	2	SH	2020
GOMBE - YOLA	330	240	2	2	BA	2021
MAIDUGURI - DAMATURU	330	260	2	2	BA	2021
ZUNGERU - GWAGWALADA	330	185	2	2	SH	2021
YOLA - JALINGO	330	160	2	2	BA	2022

Line Name	Voltage (V)	Length (km)	No. of circuits	No. of conductors	TCN region	Commission date
SOKOTO - TMAFARA	330	125	2	2	SH	2023
TMAFARA - GUSAU	330	85	2	2	SH	2023
BALI - JALINGO	330	294	2	2	BA	2024
BALI - MAKURDI	330	139	2	4	BA	2024
GUSAU - KATSINA	330	125	2	2	KA	2024
BALI - MAMBILLA	330	139	2	4	SH	2024
BALI - MAMBILLA	330	139	2	4	SH	2024

New 330/132 substations required

Substation Name	Voltage	330/132 transformers		132/33 transformers	TCN region	Commission date
		No. of 330kV	No. of 150MVA	No. of 60MVA		
ZENGERU	330	12			SH	2021
MAMBILLA	330	14			BA	2024
OBAJANA	330/132	2	2		BE	2014
AKURE	330/132	4	1		OS	2015
KATSINA	330/132	4	2		KA	2020
SOKOTO	330/132	4	2		SH	2020
GUSAU	330/132	4	2		KA	2023
TMAFARA	330/132	4	2		SH	2023
BALI	330/132	8	1		BA	2024
Damaturu	330/132/33	2	2		BA	2015
Maiduguri	330/132/33	1	2		BA	2015
Epe	330/132/33	4	2	2	LA	2016
Agbara	330/132/33	6	2		LA	2018
New Apo	330/132/33	4	2		SH	2019

Annex 5: VOLTAGE SUPPORT EQUIPMENT

Existing reactors and capacitors

Substation Name	Geographical area	Voltage	Total number of reactors/capacitors			Age
			330kV React	132kV Cap	33kV Cap	
Alaoji	PH	330/132	1			1978
Ikeja-West	LA	330/132	2			1977
Ajaokuta	BE	330/132/33	1			1981
Ayede	OS	330/132/33			2	1977
Benin	BE	330/132/33	1			1977
Gombe	BA	330/132/33	1			1979
Jebba TS	SH	330/132/33	2			1968
Kumbotso (Kano)	KA	330/132/33	1		1	1977
New Haven (Enugu)	EN	330/132/33	1			1981
Onitsha	EN	330/132/33	1			1968
Oshogbo	OS	330/132/33	1			1974
Yola	BA	330/132/33	3			1978
Abeokuta	LA	132/33			2	1979
Agbara	LA	132/33			1	1982
Akure	OS	132/33			1	1964
Akwanga	SH	132/33			1	1996
Amukpe	BE	132/33			1	2007
Apir	EN	132/33			1	2001
Awka	EN	132/33			1	2002
Dakata	KA	132/33			1	1978
Dan-Agundi	KA	132/33			1	1999
Effurun	BE	132/33			1	1975
Hadejia	KA	132/33			1	1975
Ife	OS	132/33			1	1979
Ijebu-Ode	OS	132/33			1	1979
Ikorodu	LA	132/33			2	1999

Substation Name	Geographical area	Voltage	Total number of reactors/capacitors			Age
			330kV React	132kV Cap	33kV Cap	
Ilorin	OS	132/33			1	1982
Ilupeju	LA	132/33			1	1974
Irrua	BE	132/33			1	2002
Iseyin	OS	132/33			1	1982
Kaduna town	KA	132/33			2	1975
Karu	SH	132/33	1			2011
Kubuwa	SH	132/33			1	2011
Ojo	LA	132/33			2	1965
Okene	BE	132/33			1	1987
Shagamu Cement	LA	132/33			1	1979
Uyo	PH	132/33			1	1995
Yandev	EN	132/33			1	1975
Zaria	KA	132/33			1	1998

Proposed new reactors and capacitors

Substation Name	Geographical area	Voltage	Total number of reactors/capacitors		
			330kV React	132kV Cap	33kV Cap
Damboa	BA	132	0	5	
Bauchi	BA	33	0		2
Biu	BA	33	0		1
Maid	BA	33	0		1
Effunrun	BA	33	0		7
Amukpe	BN	33	0		1
Benin	BN	33	0		4
Irrua	BN	33	0		4
Okene	BN	33	0		2
Dankata	BR	33	0		7
Dan Agundi	BR	33	0		8
New Havens	EN	132	0	3	
Oji River	EN	132	0	2	

Substation Name	Geographical area	Voltage	Total number of reactors/capacitors		
			330kV React	132kV Cap	33kV Cap
Abakiliki	EN	132	0	2	
Kano	KD	132	0	2	
Gazoua	KD	132	0	1	
Hadejia	KD	132	0	2	
Katampe	KD	132	0	3	
Tmafara	KD	33	0		1
Funtua	KD	33	0		1
Gusua	KD	33	0		1
Kankia	KD	33	0		2
Azare	KD	33	0		1
Kaduna Town	KD	33	0		1
Jericho	LA	132	0	2	
Akoka	LA	132	0	3	
Ejigbo	LA	132	0	4	
Otta	LA	132	0	1	
Appa Road	LA	132	0	4	
Ikorodu	LA	132	0	3	
Abeokuta	LA	132	0	3	
Amuwo Odofin	LA	33	0		1
Alagbon	LA	33	0		2
Alausa	LA	33	0		2
Alimosho	LA	33	0		2
Apapa Road	LA	33	0		1
Ijora	LA	33	0		1
Maryland	LA	33	0		1
Ogba	LA	33	0		3
Otta	LA	33	0		3
Oworosoki	LA	33	0		2
Papalanto	LA	33	0		2
Ilupeju	LA	33	0		1

Substation Name	Geographical area	Voltage	Total number of reactors/capacitors		
			330kV React	132kV Cap	33kV Cap
Ojo	LA	33	0		2
Ogba	LA	33	0		1
Itire	LA	33	0		2
Ilupeju	LA	33	0		4
Osogbo	OS	132	0	7	
Ondo	OS	33	0		2
Aba	PH	132	0	4	
Portharcourt Main	PH	33	0		6
Apo	SH	33	0		3
Central	SH	33	0		4
Karu	SH	33	0		2
Kubwa	SH	33	0		4
Sokoto	SH	33	0		3
Gwagwalada	SH	33	0		5
Dutse	SH	33	0		1
Brinin Kebbi	SH	33	0		1
Suleja	SH	33	0		1

Annex 6: Measured and Projected Load by Substation in TCN Region

TCN Region	Substation	Measured at 2012 (MW)	2026 Projection (MW)
Osogbo	Ondo	32.0	87
Osogbo	Akure	52.0	141
Osogbo	Ibadan North	38.7	85
Osogbo	Sagamu	35.0	77
Osogbo	Ayede	76.0	168
Osogbo	Jericho	36.7	81
Osogbo	Ijebu-Ode	38.5	85
Osogbo	Iseyin	20.0	44
Osogbo	Osogbo	93.0	205
Osogbo	Ganmo	46.6	103
Osogbo	Ilorin	46.4	102
Osogbo	Ilesa	35.1	78
Osogbo	Offa	14.8	33
Osogbo	Omu-aran	32.0	71
Osogbo	Ife	37.8	83
Bauchi	Maiduguri	40.1	115
Bauchi	Damboa	13.2	38
Bauchi	Biu	10	29
Bauchi	Yola	31.6	91
Bauchi	Savannah	6.2	18
Bauchi	Jalingo	9.7	24
Bauchi	Gombe	55.9	206
Bauchi	Jos	81	298
Bauchi	Bauchi	50.5	186
Benin	Okene	51.4	96
Benin	Geregu T.S	0	0
Benin	Ukpilla	11	30
Benin	Benin	170.9	464
Benin	Irrua	51.7	140

TCN Region	Substation	Measured at 2012 (MW)	2026 Projection (MW)
Benin	Ughelli	67.5	183
Benin	Effurun	102.2	277
Benin	Amukpe	24.6	67
Enugu	Oturkpo	5.4	20
Enugu	Yandev	24.3	89
Enugu	New Haven	82.4	204
Enugu	Abakaliki	55.2	137
Enugu	Nkalagu	11.4	28
Enugu	Onitsha	148.6	368
Enugu	Awka	44.5	110
Enugu	Oji River TS	24.5	61
Enugu	Nsukka	9.5	24
Enugu	Kingsway	0	0
Kaduna	T-Mafara	8.3	20
Kaduna	Gusau	33.8	82
Kaduna	Mando	154.2	376
Kaduna	Zaria	47	115
Kaduna	Kaduna Town	101.1	246
Kaduna	Funtua	33.2	123
Kaduna	Katsina	38.9	144
Kaduna	Kankia	19.5	72
Kaduna	Dakata	75.3	279
Kaduna	Dan-Agundi	71	263
Kaduna	Hadejia	13.6	50
Kaduna	Kumbotso	78.6	291
Kaduna	Dutse	23.2	86
Portharcourt	Aba	98.7	244.4
Portharcourt	Owerri	102.4	253.5
PORTHARCOURT	Afam	13.5	22.2
PORTHARCOURT	P.H. Main	130.2	214.1
PORTHARCOURT	P.H. Town	87.4	143.7

TCN Region	Substation	Measured at 2012 (MW)	2026 Projection (MW)
PORTHARCOURT	Ahoada	38.1	62.6
PORTHARCOURT	Yenagoa	45.4	74.6
PORTHARCOURT	Calabar	67.7	111.3
PORTHARCOURT	Eket	44.5	73.2
PORTHARCOURT	Uyo	55	90.4
PORTHARCOURT	Itu	20.4	27.6
Shiroro	Sokoto	61.8	150.7
Shiroro	Shiroro-II	12.5	23.4
Shiroro	Minna	53.1	99.3
Shiroro	Tegina	14.2	26.6
Shiroro	Apo	100.7	188.3
Shiroro	Kubwa	76.8	143.6
Shiroro	Keffi	18.1	33.9
Shiroro	Katampe	92	172.1
Shiroro	Central Area	72.3	135.2
Shiroro	Karu	37.4	69.9
Shiroro	Akwanga	25.9	48.4
Shiroro	Suleja	26	48.6
Shiroro	Jebba	23.9	44.7
Shiroro	Bida	33.4	62.5
Shiroro	Kontagora	23.9	44.7
Shiroro	Birnin-Kebbi	37.4	69.9
Lagos	Amuwo-Odofin	60	146.0
Lagos	Akangba	64	155.7
Lagos	Ojo	47	114.3
Lagos	Aja	80	194.6
Lagos	Alagbon	75	182.5
Lagos	Akoka	51	124.1
Lagos	Apapa Road	29	70.6
Lagos	Isolo	66.2	161.1
Lagos	Ijora	68.2	165.9

TCN Region	Substation	Measured at 2012 (MW)	2026 Projection (MW)
Lagos	Agbara	50.2	122.1
Lagos	Ilupeju	47.8	142.8
Lagos	Maryland	60	179.3
Lagos	Ikorodu	111	331.7
Lagos	Itire	48.1	143.7
Lagos	Ejigbo	72.1	215.5
Lagos	Oworonsoki	67	200.2
Lagos	Ogba	135	403.4
Lagos	Alimosho	89.7	257.3
Lagos	Papalanto	28.7	63.4
Lagos	Abeokuta	89.3	197.2
Lagos	Otta	83	183.3

Annex 7: NEW BUILD COST DRIVER CALCULATIONS

New line unit cost calculations

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Tow - Sus	1	330kV	A	"AAH" type Towers - 0 to 2° suspension	18,951	982	466,500	0.50	9,476	491	233,250
Tow - Sus	1	330kV	B	"AAH" type Towers - 0 to 2° suspension	24,750	1,885	508,038	0.50	12,375	943	254,019
Tow - Sus	2	330kV	A	"BBH" type Towers - 2 to 10° strain	21,278	1,098	625,000	0.50	10,639	549	312,500
Tow - Sus	2	330kV	B	"BBH" type Towers - 2 to 10° strain	43,641	3,638	708,350	0.50	21,821	1,819	354,175
Tow - Ten	3	330kV	A	"CCH" type Towers - 10 to 30° strain	25,481	1,098	725,000	0.33	8,494	366	241,667
Tow - Ten	3	330kV	B	"CCH" type Towers - 10 to 30° strain	53,686	4,646	850,350	0.33	17,895	1,549	283,450
Tow - Ten	4	330kV	A	"DDH" type Towers - 30 to 60° strain	29,671	1,098	850,000	0.33	9,890	366	283,333
Tow - Ten	4	330kV	B	"DDH" type Towers - 30 to 60° strain	68,073	5,105	1,132,500	0.33	22,691	1,702	377,500
Tow - Sus	17	330kV	A	"AAH" type tower Foundation type 1	0	0	1,884,615	0.07	0	0	134,615
Tow - Sus	17	330kV	B	"AAH" type tower Foundation type 1	0	0	4,095,000	0.07	0	0	292,500
Tow - Sus	18	330kV	A	"AAH" type tower Foundation type 2	0	0	2,281,812	0.07	0	0	162,987
Tow - Sus	18	330kV	B	"AAH" type tower Foundation type 2	0	0	4,245,000	0.07	0	0	303,214
Tow - Sus	19	330kV	A	"AAH" type tower Foundation type 3	0	0	2,708,349	0.07	0	0	193,454
Tow - Sus	19	330kV	B	"AAH" type tower Foundation type 3	0	0	4,357,000	0.07	0	0	311,214
Tow - Sus	20	330kV	A	"AAH" type tower Foundation type 4	0	0	3,512,381	0.07	0	0	250,884
Tow - Sus	20	330kV	B	"AAH" type tower Foundation type 4	0	0	4,445,000	0.07	0	0	317,500

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Tow - Sus	21	330kV	A	"AAH" type tower Foundation type 5	0	0	4,991,192	0.07	0	0	356,514
Tow - Sus	21	330kV	B	"AAH" type tower Foundation type 5	0	0	2,325,000	0.07	0	0	166,071
Tow - Sus	16	330kV	A	"AAH" type tower Foundation type R	0	0	1,469,991	0.07	0	0	104,999
Tow - Sus	16	330kV	B	"AAH" type tower Foundation type R	0	0	1,895,000	0.07	0	0	135,357
Tow - Sus	22	330kV	A	"AAH" type tower Foundation type S	0	0	5,811,565	0.07	0	0	415,112
Tow - Sus	22	330kV	B	"AAH" type tower Foundation type S	0	0	2,895,000	0.07	0	0	206,786
Tow - Sus	25	330kV	A	"BBH" type tower Foundation type 1	0	0	2,056,465	0.07	0	0	146,890
Tow - Sus	25	330kV	B	"BBH" type tower Foundation type 1	0	0	2,300,000	0.07	0	0	164,286
Tow - Sus	26	330kV	A	"BBH" type tower Foundation type 2	0	0	2,458,835	0.07	0	0	175,631
Tow - Sus	26	330kV	B	"BBH" type tower Foundation type 2	0	0	2,359,000	0.07	0	0	168,500
Tow - Sus	27	330kV	A	"BBH" type tower Foundation type 3	0	0	3,125,770	0.07	0	0	223,269
Tow - Sus	27	330kV	B	"BBH" type tower Foundation type 3	0	0	2,515,000	0.07	0	0	179,643
Tow - Sus	28	330kV	A	"BBH" type tower Foundation type 4	0	0	3,754,450	0.07	0	0	268,175
Tow - Sus	28	330kV	B	"BBH" type tower Foundation type 4	0	0	2,495,000	0.07	0	0	178,214
Tow - Sus	29	330kV	A	"BBH" type tower Foundation type 5	0	0	4,270,815	0.07	0	0	305,058
Tow - Sus	29	330kV	B	"BBH" type tower Foundation type 5	0	0	3,855,000	0.07	0	0	275,357
Tow - Sus	24	330kV	A	"BBH" type tower Foundation type R	0	0	1,229,790	0.07	0	0	87,842
Tow - Sus	24	330kV	B	"BBH" type tower Foundation type R	0	0	2,245,000	0.07	0	0	160,357
Tow - Sus	30	330kV	A	"BBH" type tower Foundation type S	0	0	5,735,115	0.07	0	0	409,651

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Tow - Sus	30	330kV	B	"BBH" type tower Foundation type S	0	0	7,895,000	0.07	0	0	563,929
Tow - Ten	33	330kV	A	"CCH" type tower Foundation type 1	0	0	2,181,400	0.05	0	0	99,155
Tow - Ten	33	330kV	B	"CCH" type tower Foundation type 1	0	0	5,850,000	0.05	0	0	265,909
Tow - Ten	34	330kV	A	"CCH" type tower Foundation type 2	0	0	2,622,750	0.05	0	0	119,216
Tow - Ten	34	330kV	B	"CCH" type tower Foundation type 2	0	0	2,950,000	0.05	0	0	134,091
Tow - Ten	35	330kV	A	"CCH" type tower Foundation type 3	0	0	2,314,415	0.05	0	0	105,201
Tow - Ten	35	330kV	B	"CCH" type tower Foundation type 3	0	0	3,385,000	0.05	0	0	153,864
Tow - Ten	36	330kV	A	"CCH" type tower Foundation type 4	0	0	3,978,000	0.05	0	0	180,818
Tow - Ten	36	330kV	B	"CCH" type tower Foundation type 4	0	0	3,950,000	0.05	0	0	179,545
Tow - Ten	37	330kV	A	"CCH" type tower Foundation type 5	0	0	4,524,295	0.05	0	0	205,650
Tow - Ten	37	330kV	B	"CCH" type tower Foundation type 5	0	0	4,250,000	0.05	0	0	193,182
Tow - Ten	32	330kV	A	"CCH" type tower Foundation type R	0	0	1,672,285	0.05	0	0	76,013
Tow - Ten	32	330kV	B	"CCH" type tower Foundation type R	0	0	2,825,000	0.05	0	0	128,409
Tow - Ten	38	330kV	A	"CCH" type tower Foundation type S	0	0	6,168,250	0.05	0	0	280,375
Tow - Ten	38	330kV	B	"CCH" type tower Foundation type S	0	0	7,950,000	0.05	0	0	361,364
Tow - Ten	41	330kV	A	"DDH" type tower Foundation type 1	0	0	2,312,900	0.05	0	0	105,132
Tow - Ten	41	330kV	B	"DDH" type tower Foundation type 1	0	0	5,193,000	0.05	0	0	236,045
Tow - Ten	42	330kV	A	"DDH" type tower Foundation type 2	0	0	2,886,850	0.05	0	0	131,220
Tow - Ten	42	330kV	B	"DDH" type tower Foundation type 2	0	0	4,154,000	0.05	0	0	188,818

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Tow - Ten	43	330kV	A	"DDH" type tower Foundation type 3	0	0	2,848,650	0.05	0	0	129,484
Tow - Ten	43	330kV	B	"DDH" type tower Foundation type 3	0	0	5,542,000	0.05	0	0	251,909
Tow - Ten	44	330kV	A	"DDH" type tower Foundation type 4	0	0	3,587,850	0.05	0	0	163,084
Tow - Ten	44	330kV	B	"DDH" type tower Foundation type 4	0	0	4,495,000	0.05	0	0	204,318
Tow - Ten	45	330kV	A	"DDH" type tower Foundation type 5	0	0	3,993,500	0.05	0	0	181,523
Tow - Ten	45	330kV	B	"DDH" type tower Foundation type 5	0	0	6,950,000	0.05	0	0	315,909
Tow - Ten	40	330kV	A	"DDH" type tower Foundation type R	0	0	1,771,800	0.05	0	0	80,536
Tow - Ten	40	330kV	B	"DDH" type tower Foundation type R	0	0	3,423,000	0.05	0	0	155,591
Tow - Ten	46	330kV	A	"DDH" type tower Foundation type S	0	0	6,714,750	0.05	0	0	305,216
Tow - Ten	46	330kV	B	"DDH" type tower Foundation type S	0	0	10,240,000	0.05	0	0	465,455
Tow - Ten	56	330kV	A	"EEH" type tower Extra length of pile foundation (deeper than 10m)	0	0	65,457	0.00	0	0	0
Tow - Ten	56	330kV	B	"EEH" type tower Extra length of pile foundation (deeper than 10m)	0	0	52,500	0.00	0	0	0
Tow - Ten	54	330kV	A	"EEH" type tower Foundation for special connecting terminal tower	0	0	6,247,230	0.05	0	0	283,965
Tow - Ten	54	330kV	B	"EEH" type tower Foundation for special connecting terminal tower	0	0	11,709,000	0.05	0	0	532,227
Tow - Ten	49	330kV	A	"EEH" type tower Foundation type 1	0	0	2,448,500	0.05	0	0	111,295
Tow - Ten	49	330kV	B	"EEH" type tower Foundation type 1	0	0	4,154,000	0.05	0	0	188,818
Tow - Ten	50	330kV	A	"EEH" type tower Foundation type 2	0	0	2,025,565	0.05	0	0	92,071

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Tow - Ten	50	330kV	B	"EEH" type tower Foundation type 2	0	0	4,643,000	0.05	0	0	211,045
Tow - Ten	51	330kV	A	"EEH" type tower Foundation type 3	0	0	3,371,006	0.05	0	0	153,228
Tow - Ten	51	330kV	B	"EEH" type tower Foundation type 3	0	0	5,273,000	0.05	0	0	239,682
Tow - Ten	52	330kV	A	"EEH" type tower Foundation type 4	0	0	3,798,960	0.05	0	0	172,680
Tow - Ten	52	330kV	B	"EEH" type tower Foundation type 4	0	0	5,982,500	0.05	0	0	271,932
Tow - Ten	53	330kV	A	"EEH" type tower Foundation type 5	0	0	4,228,800	0.05	0	0	192,218
Tow - Ten	53	330kV	B	"EEH" type tower Foundation type 5	0	0	8,378,000	0.05	0	0	380,818
Tow - Ten	48	330kV	A	"EEH" type tower Foundation type R	0	0	1,875,800	0.05	0	0	85,264
Tow - Ten	48	330kV	B	"EEH" type tower Foundation type R	0	0	4,928,000	0.05	0	0	224,000
Tow - Ten	55	330kV	A	"EEH" type tower Foundation type S	0	0	6,247,230	0.05	0	0	283,965
Tow - Ten	55	330kV	B	"EEH" type tower Foundation type S	0	0	11,709,000	0.05	0	0	532,227
Tow - Ten	5	330kV	A	"EEH" type Towers - 60 to 90° strain + DE	34,393	1,098	880,500	0.33	11,464	366	293,500
Tow - Ten	5	330kV	B	"EEH" type Towers - 60 to 90° strain + DE	73,518	5,702	1,279,048	0.33	24,506	1,901	426,349
Null	6	330kV	A	1.0m leg extension	880	509	32,000	0.00	0	0	0
Null	6	330kV	B	1.0m leg extension	880	509	32,000	0.00	0	0	0
Null	7	330kV	A	2.m leg extension	1,443	525	36,000	0.00	0	0	0
Null	7	330kV	B	2.m leg extension	1,443	525	36,000	0.00	0	0	0
Wire	59	330kV	A	Accessories for ACSR (Bison) Conductor	113	15	2,625	1.00	113	15	2,625
Wire	145	330kV	B	Accessories for ACSR (Bison) Conductor	1,374	224	18,000	1.00	1,374	224	18,000

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
OPGW	63	330kV	A	Accessories for OPGW overhead ground wire	41	5	1,575	1.00	41	5	1,575
OPGW	149	330kV	B	Accessories for OPGW overhead ground wire	189	93	5,600	1.00	189	93	5,600
Ground Wire	62	330kV	A	Accessories for steel overhead ground wire	41	5	1,575	1.00	41	5	1,575
Ground Wire	148	330kV	B	Accessories for steel overhead ground wire	90	43	3,800	1.00	90	43	3,800
Wire	58	330kV	A	ACSR BISON Conductor	6,602	182	131,250	1.00	6,602	182	131,250
Wire	144	330kV	B	ACSR BISON Conductor	5,632	1,150	90,000	1.00	5,632	1,150	90,000
Null	12	330kV	A	Aerial Plate for Tower at every 10th Tower.	51	12	2,800	0.00	0	0	0
Null	12	330kV	B	Aerial Plate for Tower at every 10th Tower.	51	12	2,800	0.00	0	0	0
Ground Wire	68	330kV	A	Aircraft daylight warning spheres on ground wire	151	9	3,150	1.00	151	9	3,150
Ground Wire	154	330kV	B	Aircraft daylight warning spheres on ground wire	52	13	3,900	1.00	52	13	3,900
Wire	67	330kV	A	Aircraft daylight warning spheres on phase cond.	151	9	3,150	1.00	151	9	3,150
Wire	153	330kV	B	Aircraft daylight warning spheres on phase cond.	52	13	3,900	1.00	52	13	3,900
Null	72	330kV	A	Armour rod for ACSR BEAR (N/A)	0	0	0	0.00	0	0	0
Null	73	330kV	A	Armour rod for ACSR BISON Conductor	41	4	0	0.00	0	0	0
Null	8	330kV	A	Body Extension +3m	1,983	370	74,000	0.00	0	0	0
Null	8	330kV	B	Body Extension +3m	1,983	370	74,000	0.00	0	0	0
Null	9	330kV	A	Body Extension +6m	2,184	440	99,000	0.00	0	0	0

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Null	9	330kV	B	Body Extension +6m	2,184	440	99,000	0.00	0	0	0
Null	10	330kV	A	Body Extension +9m	3,450	571	154,000	0.00	0	0	0
Null	10	330kV	B	Body Extension +9m	3,450	571	154,000	0.00	0	0	0
Insulator	78	330kV	A	Conductor double suspension insulator strings	471	8	650	0.33	157	3	217
Insulator	160	330kV	B	Conductor double suspension insulator strings	494	131	1,500	0.33	165	44	500
Insulator	80	330kV	A	Conductor double tension string with all fittings	602	8	650	0.33	201	3	217
Insulator	162	330kV	B	Conductor double tension string with all fittings	1,065	131	1,500	0.33	355	44	500
Insulator	77	330kV	A	Conductor suspension insulator string	309	8	650	0.17	51	1	108
Insulator	159	330kV	B	Conductor suspension insulator string	471	131	1,500	0.17	78	22	250
Insulator	79	330kV	A	Conductor tensions string with all fittings.	533	8	650	0.17	89	1	108
Insulator	161	330kV	B	Conductor tensions string with all fittings.	756	131	1,500	0.17	126	22	250
Insulator	71	330kV	A	Counter weight (50 kg) for suspension string and jumpers	56	4	893	0.17	9	1	149
Insulator	157	330kV	B	Counter weight (50 kg) for suspension string and jumpers	59	22	1,700	0.17	10	4	283
Ground Wire	65	330kV	A	ground wire vibration damper (330 kV)	15	4	368	1.00	15	4	368
Ground Wire	151	330kV	B	ground wire vibration damper (330 kV)	36	19	635	1.00	36	19	635
Null	74	330kV	A	Insulated cable - 400 mm², single core, 145 kV XLPE (770 A), two conductors per phase.	0	0	0	0.00	0	0	0

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Wire	64	330kV	A	Line Conductor Vibration Dampers (330 kV)	17	2	220	1.00	17	2	220
Wire	150	330kV	B	Line Conductor Vibration Dampers (330 kV)	69	19	3,700	1.00	69	19	3,700
OPGW	66	330kV	A	OPGW ground wire vibration damper (330 kV)	22	5	600	1.00	22	5	600
OPGW	152	330kV	B	OPGW ground wire vibration damper (330 kV)	37	19	635	1.00	37	19	635
OPGW	61	330kV	A	OPGW overhead ground wire (24 fibres)	4,001	182	73,500	1.00	4,001	182	73,500
OPGW	147	330kV	B	OPGW overhead ground wire (24 fibres)	6,653	77	8,500	1.00	6,653	77	8,500
OPGW	85	330kV	A	OPGW splice attachment, including accessories	101	6	650	1.00	101	6	650
OPGW	167	330kV	B	OPGW splice attachment, including accessories	170	131	1,500	1.00	170	131	1,500
OPGW	83	330kV	A	OPGW suspension attachment, including clamp	52	6	650	1.11	58	7	722
OPGW	165	330kV	B	OPGW suspension attachment, including clamp	96	131	1,500	1.11	107	146	1,667
OPGW	84	330kV	A	OPGW tension attachment, including clamp	77	6	650	1.11	86	7	722
OPGW	166	330kV	B	OPGW tension attachment, including clamp	108	131	1,500	1.11	120	146	1,667
Null	75	330kV	A	Set of terminal cables (12), connectors and all required accessories to connect the transmission line to the insulated cables.	0	0	0	0.00	0	0	0
Null	11	330kV	A	Special terminal tower for connecting to the National Grid and all accessories	126,763	6,177	6,427,966	0.00	0	0	0
Null	11	330kV	B	Special terminal tower for connecting to the National Grid and all accessories	126,763	6,177	6,427,966	0.00	0	0	0

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Ground Wire	81	330kV	A	Steel ground wire suspension attachment, including clamp	39	6	650	1.11	43	7	722
Ground Wire	163	330kV	B	Steel ground wire suspension attachment, including clamp	73	131	1,500	1.11	81	146	1,667
Ground Wire	82	330kV	A	Steel ground wire tension attachment including clamp	36	6	650	1.11	40	7	722
Ground Wire	164	330kV	B	Steel ground wire tension attachment including clamp	82	131	1,500	1.11	91	146	1,667
Ground Wire	60	330kV	A	Steel overhead ground wire	1,256	182	42,000	1.00	1,256	182	42,000
Ground Wire	146	330kV	B	Steel overhead ground wire	571	517	20,000	1.00	571	517	20,000
Tow - Sus	13	330kV	A	Tower accessories and signs (for any tower)	162	69	6,500	1.00	162	69	6,500
Tow - Sus	13	330kV	B	Tower accessories and signs (for any tower)	162	69	6,500	1.00	162	69	6,500
Tow - Ten	13	330kV	A	Tower accessories and signs (for any tower)	162	69	6,500	1.00	162	69	6,500
Tow - Ten	13	330kV	B	Tower accessories and signs (for any tower)	162	69	6,500	1.00	162	69	6,500
Wire	70	330kV	A	Twin bundle spacer, 330 mm	35	4	788	1.00	35	4	788
Wire	156	330kV	B	Twin bundle spacer, 330 mm	32	8	350	1.00	32	8	350
Wire	69	330kV	A	Twin bundle spacer-damper 450 mm (330 kV only)	35	4	788	1.00	35	4	788
Wire	155	330kV	B	Twin bundle spacer-damper 450 mm (330 kV only)	32	8	350	1.00	32	8	350
Tow - Sus	28	132kV	A	"DD10" type tower Foundation type Pile	0	0	1,372,450	0.07	-	-	98,032
Tow - Sus	112	132kV	B	"DD10" type tower Foundation type Pile	0	0	3,250,000	0.07	-	-	232,143

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Tow - Sus	23	132kV	A	"DD10" type tower Foundation type 1	0	0	686,495	0.07	-	-	49,035
Tow - Sus	107	132kV	B	"DD10" type tower Foundation type 1	0	0	827,955	0.07	-	-	59,140
Tow - Sus	24	132kV	A	"DD10" type tower Foundation type 2	0	0	748,575	0.07	-	-	53,470
Tow - Sus	108	132kV	B	"DD10" type tower Foundation type 2	0	0	1,100,000	0.07	-	-	78,571
Tow - Sus	25	132kV	A	"DD10" type tower Foundation type 3	0	0	810,957	0.07	-	-	57,926
Tow - Sus	109	132kV	B	"DD10" type tower Foundation type 3	0	0	1,195,000	0.07	-	-	85,357
Tow - Sus	26	132kV	A	"DD10" type tower Foundation type 4	0	0	873,565	0.07	-	-	62,398
Tow - Sus	110	132kV	B	"DD10" type tower Foundation type 4	0	0	1,416,650	0.07	-	-	101,189
Tow - Sus	27	132kV	A	"DD10" type tower Foundation type 5	0	0	1,122,865	0.07	-	-	80,205
Tow - Sus	111	132kV	B	"DD10" type tower Foundation type 5	0	0	2,745,000	0.07	-	-	196,071
Tow - Sus	22	132kV	A	"DD10" type tower Foundation type R	0	0	1,497,155	0.07	-	-	106,940
Tow - Sus	106	132kV	B	"DD10" type tower Foundation type R	0	0	817,685	0.07	-	-	58,406
Tow - Sus	20	132kV	A	"DD2" type tower Foundation type Pile	0	0	1,497,155	0.07	-	-	106,940
Tow - Sus	104	132kV	B	"DD2" type tower Foundation type Pile	0	0	2,950,000	0.07	-	-	210,714
Tow - Sus	15	132kV	A	"DD2" type tower Foundation type 1	0	0	598,860	0.07	-	-	42,776
Tow - Sus	99	132kV	B	"DD2" type tower Foundation type 1	0	0	365,600	0.07	-	-	26,114
Tow - Sus	16	132kV	A	"DD2" type tower Foundation type 2	0	0	673,750	0.07	-	-	48,125
Tow - Sus	100	132kV	B	"DD2" type tower Foundation type 2	0	0	463,500	0.07	-	-	33,107
Tow - Sus	17	132kV	A	"DD2" type tower Foundation type 3	0	0	748,575	0.07	-	-	53,470

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Tow - Sus	101	132kV	B	"DD2" type tower Foundation type 3	0	0	561,650	0.07	-	-	40,118
Tow - Sus	18	132kV	A	"DD2" type tower Foundation type 4	0	0	898,295	0.07	-	-	64,164
Tow - Sus	102	132kV	B	"DD2" type tower Foundation type 4	0	0	683,550	0.07	-	-	48,825
Tow - Sus	19	132kV	A	"DD2" type tower Foundation type 5	0	0	1,197,750	0.07	-	-	85,554
Tow - Sus	103	132kV	B	"DD2" type tower Foundation type 5	0	0	1,311,300	0.07	-	-	93,664
Tow - Sus	14	132kV	A	"DD2" type tower Foundation type R	0	0	1,676,136	0.07	-	-	119,724
Tow - Sus	98	132kV	B	"DD2" type tower Foundation type R	0	0	388,100	0.07	-	-	27,721
Tow - Ten	36	132kV	A	"DD30" type tower Foundation type	0	0	1,559,550	0.05	-	-	70,889
Tow - Ten	120	132kV	B	"DD30" type tower Foundation type	0	0	3,450,000	0.05	-	-	156,818
Tow - Ten	31	132kV	A	"DD30" type tower Foundation type 1	0	0	748,575	0.05	-	-	34,026
Tow - Ten	115	132kV	B	"DD30" type tower Foundation type 1	0	0	728,500	0.05	-	-	33,114
Tow - Ten	32	132kV	A	"DD30" type tower Foundation type 2	0	0	873,350	0.05	-	-	39,698
Tow - Ten	116	132kV	B	"DD30" type tower Foundation type 2	0	0	1,071,500	0.05	-	-	48,705
Tow - Ten	33	132kV	A	"DD30" type tower Foundation type 3	0	0	998,150	0.05	-	-	45,370
Tow - Ten	117	132kV	B	"DD30" type tower Foundation type 3	0	0	1,355,950	0.05	-	-	61,634
Tow - Ten	34	132kV	A	"DD30" type tower Foundation type 4	0	0	1,122,865	0.05	-	-	51,039
Tow - Ten	118	132kV	B	"DD30" type tower Foundation type 4	0	0	1,714,950	0.05	-	-	77,952
Tow - Ten	35	132kV	A	"DD30" type tower Foundation type 5	0	0	1,372,389	0.05	-	-	62,381
Tow - Ten	119	132kV	B	"DD30" type tower Foundation type 5	0	0	2,665,000	0.05	-	-	121,136

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Tow - Ten	30	132kV	A	"DD30" type tower Foundation type R	0	0	1,684,295	0.05	-	-	76,559
Tow - Ten	114	132kV	B	"DD30" type tower Foundation type R	0	0	681,650	0.05	-	-	30,984
Tow - Ten	39	132kV	A	"DD60" type tower Foundation type 1	0	0	873,450	0.05	-	-	39,702
Tow - Ten	123	132kV	B	"DD60" type tower Foundation type 1	0	0	959,650	0.05	-	-	43,620
Tow - Ten	40	132kV	A	"DD60" type tower Foundation type 2	0	0	998,100	0.05	-	-	45,368
Tow - Ten	124	132kV	B	"DD60" type tower Foundation type 2	0	0	1,375,000	0.05	-	-	62,500
Tow - Ten	41	132kV	A	"DD60" type tower Foundation type 3	0	0	1,122,865	0.05	-	-	51,039
Tow - Ten	125	132kV	B	"DD60" type tower Foundation type 3	0	0	1,805,350	0.05	-	-	82,061
Tow - Ten	42	132kV	A	"DD60" type tower Foundation type 4	0	0	1,310,100	0.05	-	-	59,550
Tow - Ten	126	132kV	B	"DD60" type tower Foundation type 4	0	0	1,999,185	0.05	-	-	90,872
Tow - Ten	43	132kV	A	"DD60" type tower Foundation type 5	0	0	1,434,750	0.05	-	-	65,216
Tow - Ten	127	132kV	B	"DD60" type tower Foundation type 5	0	0	2,850,000	0.05	-	-	129,545
Tow - Ten	38	132kV	A	"DD60" type tower Foundation type R	0	0	1,871,450	0.05	-	-	85,066
Tow - Ten	122	132kV	B	"DD60" type tower Foundation type R	0	0	998,550	0.05	-	-	45,389
Tow - Ten	44	132kV	A	"DD60" type tower Foundation type S	0	0	1,621,915	0.05	-	-	73,723
Tow - Ten	128	132kV	B	"DD60" type tower Foundation type S	0	0	3,650,000	0.05	-	-	165,909
Tow - Ten	54	132kV	A	"DD90" type tower Extra length of pile foundation (deeper than 10m)	0	0	65,500	0.00	-	-	-
Tow - Ten	138	132kV	B	"DD90" type tower Extra length of pile foundation (deeper than 10m)	0	0	52,500	0.00	-	-	-

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Tow - Ten	52	132kV	A	"DD90" type tower Foundation for special connecting terminal tower	0	0	2,245,730	0.05	-	-	102,079
Tow - Ten	136	132kV	B	"DD90" type tower Foundation for special connecting terminal tower	0	0	3,650,000	0.05	-	-	165,909
Tow - Ten	47	132kV	A	"DD90" type tower Foundation type 1	0	0	1,372,390	0.05	-	-	62,381
Tow - Ten	131	132kV	B	"DD90" type tower Foundation type 1	0	0	1,228,500	0.05	-	-	55,841
Tow - Ten	48	132kV	A	"DD90" type tower Foundation type 2	0	0	1,497,150	0.05	-	-	68,052
Tow - Ten	132	132kV	B	"DD90" type tower Foundation type 2	0	0	2,081,845	0.05	-	-	94,629
Tow - Ten	49	132kV	A	"DD90" type tower Foundation type 3	0	0	1,621,915	0.05	-	-	73,723
Tow - Ten	133	132kV	B	"DD90" type tower Foundation type 3	0	0	2,403,600	0.05	-	-	109,255
Tow - Ten	50	132kV	A	"DD90" type tower Foundation type 4	0	0	1,809,100	0.05	-	-	82,232
Tow - Ten	134	132kV	B	"DD90" type tower Foundation type 4	0	0	3,100,000	0.05	-	-	140,909
Tow - Ten	51	132kV	A	"DD90" type tower Foundation type 5	0	0	1,995,205	0.05	-	-	90,691
Tow - Ten	135	132kV	B	"DD90" type tower Foundation type 5	0	0	3,350,000	0.05	-	-	152,273
Tow - Ten	46	132kV	A	"DD90" type tower Foundation type R	0	0	2,495,250	0.05	-	-	113,420
Tow - Ten	130	132kV	B	"DD90" type tower Foundation type R	0	0	1,360,000	0.05	-	-	61,818
Tow - Ten	53	132kV	A	"DD90" type tower Foundation type S	0	0	2,245,730	0.05	-	-	102,079
Tow - Ten	137	132kV	B	"DD90" type tower Foundation type S	0	0	3,650,000	0.05	-	-	165,909
Wire	57	132kV	A	Accessories for ACSR (Bear) Conductor	75	15	1,575	1.00	75	15	1,575
Wire	141	132kV	B	Accessories for ACSR (Bear) Conductor	71	15	1,575	1.00	71	15	1,575

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
OPGW	61	132kV	A	Accessories for OPGW overhead ground wire	15	2	945	1.00	15	2	945
OPGW	145	132kV	B	Accessories for OPGW overhead ground wire	29	4	945	1.00	29	4	945
Ground Wire	60	132kV	A	Accessories for steel overhead ground wire	11	1	945	1.00	11	1	945
Ground Wire	144	132kV	B	Accessories for steel overhead ground wire	22	1	945	1.00	22	1	945
Wire	56	132kV	A	ACSR (BEAR) Conductor	2,806	38	59,200	1.00	2,806	38	59,200
Wire	140	132kV	B	ACSR (BEAR) Conductor	3,311	401	64,000	1.00	3,311	401	64,000
Ground Wire	66	132kV	A	Aircraft daylight warning spheres on ground wire	75	9	1,890	1.00	75	9	1,890
Ground Wire	150	132kV	B	Aircraft daylight warning spheres on ground wire	75	9	1,890	1.00	75	9	1,890
Wire	65	132kV	A	Aircraft daylight warning spheres on phase cond.	75	9	1,890	1.00	75	9	1,890
Wire	149	132kV	B	Aircraft daylight warning spheres on phase cond.	75	9	1,890	1.00	75	9	1,890
Wire	70	132kV	A	Armour rod for ACSR BEAR	5	2	284	1.00	5	2	284
Wire	152	132kV	B	Armour rod for ACSR BEAR	7	2	284	1.00	7	2	284
Null	71	132kV	A	Armour rod for ACSR BISON Conductor (N/A)	0	0	0	0.00	-	-	-
Null	90	132kV	A	Body Extension +3m	1,906	293	8,650	0.00	-	-	-
Null	6	132kV	B	Body Extension +3m	947	155	18,000	0.00	-	-	-
Null	91	132kV	A	Body Extension +6m	3,820	463	15,350	0.00	-	-	-
Null	7	132kV	B	Body Extension +6m	1,894	464	28,500	0.00	-	-	-

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Null	92	132kV	A	Body Extension +9m	5,734	934	23,200	0.00	-	-	-
Null	8	132kV	B	Body Extension +9m	2,840	310	42,560	0.00	-	-	-
Insulator	76	132kV	A	Conductor double suspension insulator strings	250	14	578	0.33	83	5	193
Insulator	155	132kV	B	Conductor double suspension insulator strings	440	14	650	0.33	147	5	217
Insulator	78	132kV	A	Conductor double tension string with all fittings	456	14	578	0.33	152	5	193
Insulator	157	132kV	B	Conductor double tension string with all fittings	687	14	650	0.33	229	5	217
Insulator	75	132kV	A	Conductor suspension insulator string	241	14	578	0.17	40	2	96
Insulator	154	132kV	B	Conductor suspension insulator string	313	14	650	0.17	52	2	108
Insulator	77	132kV	A	Conductor tensions string with all fittings.	291	14	578	0.17	49	2	96
Insulator	156	132kV	B	Conductor tensions string with all fittings.	351	14	700	0.17	59	2	117
Insulator	69	132kV	A	Counter weight (50 kg) for suspension string and jumpers	11	8	536	0.17	2	1	89
Insulator	151	132kV	B	Counter weight (50 kg) for suspension string and jumpers	22	8	536	0.17	4	1	89
Ground Wire	63	132kV	A	ground wire vibration damper (132 kV)	15	4	221	1.00	15	4	221
Ground Wire	147	132kV	B	ground wire vibration damper (132 kV)	32	4	221	1.00	32	4	221
Null	72	132kV	A	Insulated cable - 400 mm², single core, 145 kV XLPE (770 A), two conductors per phase. N/a	0	0	0	0.00	-	-	-

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Null	93	132kV	A	Leg Extension 1.0m	895	116	17,000	0.00	-	-	-
Null	9	132kV	B	Leg Extension 1.0m	900	147	13,500	0.00	-	-	-
Null	94	132kV	A	Leg Extension 2.0m	1,798	100	25,000	0.00	-	-	-
Null	10	132kV	B	Leg Extension 2.0m	2,390	392	38,850	0.00	-	-	-
Tow - Sus	62	132kV	A	Line Conductor Vibration Dampers (132 kV)	15	2	315		-	-	-
Tow - Sus	146	132kV	B	Line Conductor Vibration Dampers (132 kV)	16	2	315		-	-	-
Tow - Ten	62	132kV	A	Line Conductor Vibration Dampers (132 kV)	15	2	315		-	-	-
Tow - Ten	146	132kV	B	Line Conductor Vibration Dampers (132 kV)	16	2	315		-	-	-
Tow - Sus	86	132kV	A	Number of "DD10" type Towers - 0 to 10° strain	12,375	1,652	111,750	0.50	6,188	826	55,875
Tow - Sus	2	132kV	B	Number of "DD10" type Towers - 0 to 10° strain	10,164	1,654	152,500	0.50	5,082	827	76,250
Tow - Sus	85	132kV	A	Number of "DD2" type Towers - 0 to 2° suspension	9,000	1,212	73,850	0.50	4,500	606	36,925
Tow - Sus	1	132kV	B	Number of "DD2" type Towers - 0 to 2° suspension	5,680	929	85,195	0.50	2,840	465	42,598
Tow - Ten	87	132kV	A	Number of "DD30" type Towers - 10 to 30° strain	15,075	1,976	124,100	0.33	5,025	659	41,367
Tow - Ten	3	132kV	B	Number of "DD30" type Towers - 10 to 30° strain	12,261	1,997	183,875	0.33	4,087	666	61,292
Tow - Ten	88	132kV	A	Number of "DD60" type Towers - 30 to 60° strain	17,100	2,284	181,650	0.33	5,700	761	60,550
Tow - Ten	4	132kV	B	Number of "DD60" type Towers - 30 to 60°	14,046	2,290	210,675	0.33	4,682	763	70,225

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
				strain							
Tow - Ten	89	132kV	A	Number of "DD90o" type Towers - 60 to 90° strain	20,250	2,717	250,350	0.33	6,750	906	83,450
Tow - Ten	5	132kV	B	Number of "DD90o" type Towers - 60 to 90° strain	16,732	2,722	250,975	0.33	5,577	907	83,658
OPGW	64	132kV	A	OPGW ground wire vibration damper (132 kV)	23	2	315	1.00	23	2	315
OPGW	148	132kV	B	OPGW ground wire vibration damper (132 kV)	25	2	315	1.00	25	2	315
OPGW	59	132kV	A	OPGW overhead ground wire (24 fibres)	3,389	38	37,800	1.00	3,389	38	37,800
OPGW	143	132kV	B	OPGW overhead ground wire (24 fibres)	3,458	575	117,650	1.00	3,458	575	117,650
OPGW	83	132kV	A	OPGW splice attachment, including accessories	101	14	578	1.00	101	14	578
OPGW	162	132kV	B	OPGW splice attachment, including accessories	216	14	650	1.00	216	14	650
OPGW	81	132kV	A	OPGW suspension attachment, including clamp	29	14	578	1.49	43	20	862
OPGW	160	132kV	B	OPGW suspension attachment, including clamp	29	14	750	1.49	43	20	1,119
OPGW	82	132kV	A	OPGW tension attachment, including clamp	47	14	578	1.49	70	20	862
OPGW	161	132kV	B	OPGW tension attachment, including clamp	47	14	650	1.49	70	20	970
Null	73	132kV	A	Set of terminal cables (12), connectors and all required accessories to connect the transmission line to the insulated cables. N/A	0	0	0	0.00	-	-	-

Cost driver	NIPP S/N	Voltage	Wind zone	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Ground Wire	79	132kV	A	Steel ground wire suspension attachment, including clamp	39	14	578	1.49	58	20	862
Ground Wire	158	132kV	B	Steel ground wire suspension attachment, including clamp	39	14	650	1.49	58	20	970
Ground Wire	80	132kV	A	Steel ground wire tension attachment including clamp	35	14	578	1.49	52	20	862
Ground Wire	159	132kV	B	Steel ground wire tension attachment including clamp	35	14	750	1.49	52	20	1,119
Ground Wire	58	132kV	A	Steel overhead ground wire	1,130	38	61,100	1.00	1,130	38	61,100
Ground Wire	142	132kV	B	Steel overhead ground wire	1,130	38	18,900	1.00	1,130	38	18,900
Tow - Sus	95	132kV	A	Tower accessories and signs (for any tower)	254	72	20,475	1.00	254	72	20,475
Tow - Sus	11	132kV	B	Tower accessories and signs (for any tower)	254	72	20,475	1.00	254	72	20,475
Tow - Ten	95	132kV	A	Tower accessories and signs (for any tower)	254	72	20,475	1.00	254	72	20,475
Tow - Ten	11	132kV	B	Tower accessories and signs (for any tower)	254	72	20,475	1.00	254	72	20,475
Null	68	132kV	A	Twin bundle spacer, 330 mm	0	0	0	0.00	-	-	-
Null	67	132kV	A	Twin bundle spacer-damper 450 mm (330 kV only) N/A	0	0	0	0.00	-	-	-

New substation cost driver calculations

Cost driver	NIPP ID	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
CBB - 132kV	4	145 kV Circuit breaker for line bay	57,273	9,184	290,000	0.20	11,455	1,837	58,000
CBB - 132kV	5	145 kV Circuit breaker for autotransformer bay	48,359	9,184	290,000	0.20	9,672	1,837	58,000

Cost driver	NIPP ID	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
CBB - 132kV	6	145 kV Circuit breaker for power transformer bay	48,359	9,184	290,000	0.20	9,672	1,837	58,000
CBB - 132kV	7	145 kV Circuit breaker for centre bay (1)	37,996	9,184	290,000	0.20	7,599	1,837	58,000
CBB - 132kV	8	145 kV Circuit breaker for centre bay (2)	37,996	9,184	290,000	0.20	7,599	1,837	58,000
CBB - 132kV	15	145 kV semi-pantograph disconnect switch	19,620	2,933	250,000	0.67	13,080	1,955	166,667
CBB - 132kV	16	145 kV disconnect switch	9,188	1,619	89,000	0.67	6,125	1,079	59,333
CBB - 132kV	17	145 kV disconnect switch with grounding blades	11,952	1,619	89,000	0.67	7,968	1,079	59,333
CBB - 132kV	18	145 kV grounding switch	5,803	864	50,000	4.00	23,212	3,458	200,000
CBB - 132kV	25	Capacitor voltage transformer, 132 kV	5,734	687	79,000	1.00	5,734	687	79,000
CBB - 132kV	27	Current transformer, 132 kV	6,079	687	120,000	2.00	12,159	1,374	240,000
CBB - 132kV	31	Surge arrester, Ur=120 kV	2,902	603	65,900	1.00	2,902	603	65,900
CBB - 132kV	43	132 kV wave trap (--> Telecom Lot)	8,981	692	98,000	0.20	1,796	138	19,600
CBB - 132kV	50	Control panels for Line-Line Diameter 132kV	46,073	9,261	450,000	0.33	15,358	3,087	150,000
CBB - 132kV	57	Line distance protection panel	69,204	9,962	7,690,000	0.20	13,841	1,992	1,538,000
CBB - 132kV	58	Line differential protection panel	69,204	9,962	4,589,000	0.20	13,841	1,992	917,800
CBB - 132kV	87	Gantry column for 132kv busbar	54,415	1,142	105,000	0.10	5,441	114	10,500
CBB - 132kV	88	Gantry beam (W=14m) for 132kv busbar	47,032	926	850,000	0.10	4,703	93	85,000
CBB - 132kV	89	Gantry beam (W=16.5m) for 132kv busbar	56,340	1,158	1,050,000	0.10	5,634	116	105,000
CBB - 132kV	92	Supports for Arrester and Post-type Insulator (H=2.7m)	33,573	710	605,000	0.10	3,357	71	60,500
CBB - 132kV	93	Supports for Instrument transformer (H=2.7m)	151,655	3,126	2,780,000	0.10	15,166	313	278,000
CBB - 132kV	104	132 kV suspension/tension string fittings	9,107	187	264,300	0.10	911	19	26,430
CBB - 132kV	106	132 kV tension string fittings	5,937	132	109,200	0.10	594	13	10,920
CBB - 132kV	109	Post-type insulator 138 kV	4,398	91	81,600	0.10	440	9	8,160
CBB - 132kV	129	Foundation - 132 kV Circuit breakers and fault thrower	0	0	13,300,000	0.10	-	-	1,330,000

Cost driver	NIPP ID	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
CBB - 132kV	130	Foundation - 132 kV disconnect switches and grounding switch	0	0	2,900,000	0.10	-	-	290,000
CBB - 132kV	131	Foundation - 132 kV Instrument transformers	0	0	8,790,000	0.10	-	-	879,000
CBB - 132kV	132	Foundation - 132 kV Post-type insulators and surge arrester	0	0	1,980,000	0.10	-	-	198,000
CBB - 132kV	137	Foundation - 132 kV busbar structure	0	0	37,100,000	0.10	-	-	3,710,000
CBB - 330kV	1	362 kV Circuit breaker for transformer bay	175,474	22,382	1,032,268	0.33	58,491	7,461	344,089
CBB - 330kV	2	362 kV Circuit breaker for centre bay	175,474	22,382	1,032,268	0.33	58,491	7,461	344,089
CBB - 330kV	3	362 kV Circuit breaker for shunt reactor bay	175,474	22,382	1,032,268	0.33	58,491	7,461	344,089
CBB - 330kV	11	362 kV semipantograph disconnect switch	66,790	5,171	241,790	0.67	44,527	3,447	161,193
CBB - 330kV	12	362 kV disconnect-switch	66,790	3,473	190,000	0.67	44,527	2,315	126,667
CBB - 330kV	13	362 kV disconnect-switch with grounding blade	66,790	1,845	190,000	0.67	44,527	1,230	126,667
CBB - 330kV	14	362 kV grounding switch	11,952	926	100,000	4.00	47,806	3,705	400,000
CBB - 330kV	24	Capacitor voltage transformer, 330 kV	6,494	926	80,000	1.00	6,494	926	80,000
CBB - 330kV	26	Current transformer, 330 kV	16,081	849	170,000	2.00	32,162	1,698	340,000
CBB - 330kV	30	Surge arrester, Ur=288 kV	8,705	772	78,900	1.00	8,705	772	78,900
CBB - 330kV	42	330 kV wave trap (--> Telecom Lot)	19,295	926	128,000	0.29	5,513	265	36,571
CBB - 330kV	46	Control panels for Line-Line Diameter 330kV	46,391	9,795	250,000	0.33	15,464	3,265	83,333
CBB - 330kV	49	Control panels for Transfo.-Transfo. Diameter 330kV	46,073	9,261	450,000	0.00	-	-	-
CBB - 330kV	57	Line distance protection panel	69,204	9,962	7,690,000	0.29	19,773	2,846	2,197,143
CBB - 330kV	58	Line differential protection panel	69,204	9,962	4,589,000	0.29	19,773	2,846	1,311,143
CBB - 330kV	86	Gantry sheild wire mast for 12m height busbar	4,013	0	40,000	0.14	573	-	5,714
CBB - 330kV	95	Gantry column for 19m height busbar	143,718	5,788	1,352,000	0.14	20,531	827	193,143
CBB - 330kV	96	Gantry beam for 19m height busbar	52,095	1,158	750,000	0.14	7,442	165	107,143

Cost driver	NIPP ID	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
CBB - 330kV	98	Supports for Arrester and Post-type Insulator (H=3.5m)	10,766	446	105,000	0.14	1,538	64	15,000
CBB - 330kV	99	Supports for Instrument transformer (H=3.5m)	26,688	1,077	252,100	0.14	3,813	154	36,014
CBB - 330kV	102	Hardware for shield wire	6,888	143	128,200	0.14	984	20	18,314
CBB - 330kV	103	330 kV suspension string fittings	12,194	245	218,200	0.14	1,742	35	31,171
CBB - 330kV	105	330 kV tension string fittings	7,350	148	135,400	0.14	1,050	21	19,343
CBB - 330kV	107	Porcelain string insulators, 120 KN	58,663	1,267	1,075,000	0.14	8,380	181	153,571
CBB - 330kV	108	Post-type insulator 330 kV	5,875	131	107,200	0.14	839	19	15,314
CBB - 330kV	113	Conductor, aluminum alloy, 800 mm²	53,832	1,077	969,300	0.14	7,690	154	138,471
CBB - 330kV	114	Accessories for aluminum alloy conductor	8,798	178	159,400	0.14	1,257	25	22,771
CBB - 330kV	115	Busbar connectors and hardware	11,710	194	220,000	0.14	1,673	28	31,429
CBB - 330kV	126	Foundation - 330 kV disconnect switches	0	0	13,750,000	0.14	-	-	1,964,286
CBB - 330kV	127	Foundation - 330 kV Instrument transformers	0	0	16,560,000	0.14	-	-	2,365,714
CBB - 330kV	128	Foundation - 330 kV Post-type insulators and surge arrester	0	0	2,250,000	0.14	-	-	321,429
CBB - 330kV	136	Foundation - 330 kV busbar structure	0	0	71,500,000	0.14	-	-	10,214,286
CBB - 33kV	9	36 kV Circuit breaker	25,918	856	200,000	1.00	25,918	856	200,000
CBB - 33kV	21	36 kV disconnect-switch	6,603	99	56,099	2.00	13,205	198	112,198
CBB - 33kV	23	36 kV grounding switch	2,574	99	45,900	4.00	10,296	395	183,600
CBB - 33kV	28	Voltage transformer, 33 kV	1,313	93	23,900	2.00	2,625	185	47,800
CBB - 33kV	29	Current transformer, 33 kV	1,078	77	23,900	4.00	4,311	309	95,600
CBB - 33kV	32	Surge arrester, Ur=30 kV	1,368	100	23,790	1.00	1,368	100	23,790
CBB - 33kV	54	Control for 33 kV transfer circuit breaker	53,958	2,694	340,000	1.00	53,958	2,694	340,000
CBB - 33kV	90	Three-module 33kv switchgear structure	30,254	633	552,000	0.33	10,085	211	184,000

Cost driver	NIPP ID	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
CBB - 33kV	94	Gantry column for 33kv busbar	9,501	220	179,440	0.33	3,167	73	59,813
CBB - 33kV	110	Post-type insulator 33 kV	1,582	39	27,100	0.33	527	13	9,033
CBB - 33kV	133	Foundation - 36 kV Circuit breakers	0	0	197,358	0.33	-	-	65,786
CBB - 33kV	138	Foundation - 33 kV modular structure	0	0	10,300,000	0.33	-	-	3,433,333
CBB - 33kV	139	Foundation - 33 kV insulated cable support	0	0	188,511	0.33	-	-	62,837
CBB - 33kV	140	Foundation - 33 kV Instrument transformers	0	0	1,530,000	0.33	-	-	510,000
React/Cap - 330kV 75MVAR Reactor	37	Shunt reactor, 330 kV, 75 MVAR	1,466,389	27,012	21,600,000	1.00	1,466,389	27,012	21,600,000
React/Cap - 330kV 75MVAR Reactor	60	Protection panel for Shunt Reactor	54,524	9,962	0	1.00	54,524	9,962	-
React/Cap - 330kV 75MVAR Reactor	120	Foundation - 330 kV, 75 MVAR shunt reactor	0	0	5,780,000	1.00	-	-	5,780,000
React/Cap - 330kV 75MVAR Reactor	124	Foundation - Oil separator for the 50 MVA transformer or shunt reactor	0	0	2,650,000	1.00	-	-	2,650,000
Sub Gen - 132/33kV	41	Foundation - Substation Service Transformer	27,012	439	125,900	1.00	27,012	439	125,900
Sub Gen - 132/33kV	53	Substation automation	451,492	84,742	0	1.00	451,492	84,742	-
Sub Gen - 132/33kV	62	132kV Busbar Protection System	111,179	17,674	0	1.00	111,179	17,674	-
Sub Gen - 132/33kV	65	Data analysis station	81,037	1,628	1,500,000	1.00	81,037	1,628	1,500,000
Sub Gen - 132/33kV	66	Remote digital fault recorder	30,100	5,017	80,000	1.00	30,100	5,017	80,000
Sub Gen - 132/33kV	69	Remote digital fault locator	28,556	4,631	75,000	1.00	28,556	4,631	75,000
Sub Gen - 132/33kV	73	Automatic transfer switch	13,892	27,784	260,000	1.00	13,892	27,784	260,000
Sub Gen - 132/33kV	76	Distribution panel, 110 Vcc, 225 A - Type 1	20,993	41,908	378,000	1.00	20,993	41,908	378,000
Sub Gen - 132/33kV	77	Diesel generator set, 50 kw	15,293	6,522	495,000	1.00	15,293	6,522	495,000
Sub Gen - 132/33kV	79	Battery, 48 Vdc, 200 A-h	8,532	19,295	180,000	1.00	8,532	19,295	180,000

Cost driver	NIPP ID	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Sub Gen - 132/33kV	81	Battery, Charger, 48 Vcd, 60 A	5,518	10,805	105,000	1.00	5,518	10,805	105,000
Sub Gen - 132/33kV	91	Support for MV insulated cable and cable terminal	1,929	59	42,500	1.00	1,929	59	42,500
Sub Gen - 132/33kV	125	Foundation - Substation service transformer	0	0	4,250,000	1.00	-	-	4,250,000
Sub Gen - 330/132/33kV	41	Substation Service Transformer	27,012	439	125,900	1.00	27,012	439	125,900
Sub Gen - 330/132/33kV	53	Substation automation	451,492	84,742	0	1.00	451,492	84,742	-
Sub Gen - 330/132/33kV	61	330kV Busbar Protection System	131,874	22,443	450,000	1.00	131,874	22,443	450,000
Sub Gen - 330/132/33kV	62	132kV Busbar Protection System	111,179	17,674	0	1.00	111,179	17,674	-
Sub Gen - 330/132/33kV	65	Data analysis station	81,037	1,628	1,500,000	1.00	81,037	1,628	1,500,000
Sub Gen - 330/132/33kV	66	Remote digital fault recorder	30,100	5,017	80,000	1.00	30,100	5,017	80,000
Sub Gen - 330/132/33kV	69	Remote digital fault locator	28,556	4,631	75,000	1.00	28,556	4,631	75,000
Sub Gen - 330/132/33kV	73	Automatic transfer switch	13,892	27,784	260,000	1.00	13,892	27,784	260,000
Sub Gen - 330/132/33kV	76	Distribution panel, 110 Vcc, 225 A - Type 1	20,993	41,908	378,000	1.00	20,993	41,908	378,000
Sub Gen - 330/132/33kV	77	Diesel generator set, 50 kw	15,293	6,522	495,000	1.00	15,293	6,522	495,000
Sub Gen - 330/132/33kV	79	Battery, 48 Vdc, 200 A-h	8,532	19,295	180,000	1.00	8,532	19,295	180,000
Sub Gen - 330/132/33kV	81	Battery, Charger, 48 Vcd, 60 A	5,518	10,805	105,000	1.00	5,518	10,805	105,000
Sub Gen - 330/132/33kV	91	Support for MV insulated cable and cable terminal	1,929	59	42,500	1.00	1,929	59	42,500
Sub Gen - 330/132/33kV	125	Foundation - Substation service transformer	0	0	4,250,000	1.00	-	-	4,250,000
Sub Gen - 330/132kV	41	Foundation - Substation Service Transformer	27,012	439	125,900	1.00	27,012	439	125,900
Sub Gen - 330/132kV	53	Substation automation	451,492	84,742	0	1.00	451,492	84,742	-
Sub Gen - 330/132kV	61	330kV Busbar Protection System	131,874	22,443	450,000	1.00	131,874	22,443	450,000
Sub Gen - 330/132kV	62	132kV Busbar Protection System	111,179	17,674	0	1.00	111,179	17,674	-
Sub Gen - 330/132kV	65	Data analysis station	81,037	1,628	1,500,000	1.00	81,037	1,628	1,500,000
Sub Gen - 330/132kV	66	Remote digital fault recorder	30,100	5,017	80,000	1.00	30,100	5,017	80,000

Cost driver	NIPP ID	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Sub Gen - 330/132kV	69	Remote digital fault locator	28,556	4,631	75,000	1.00	28,556	4,631	75,000
Sub Gen - 330/132kV	73	Automatic transfer switch	13,892	27,784	260,000	1.00	13,892	27,784	260,000
Sub Gen - 330/132kV	76	Distribution panel, 110 Vcc, 225 A - Type 1	20,993	41,908	378,000	1.00	20,993	41,908	378,000
Sub Gen - 330/132kV	77	Diesel generator set, 50 kw	15,293	6,522	495,000	1.00	15,293	6,522	495,000
Sub Gen - 330/132kV	79	Battery, 48 Vdc, 200 A-h	8,532	19,295	180,000	1.00	8,532	19,295	180,000
Sub Gen - 330/132kV	81	Battery, Charger, 48 Vcd, 60 A	5,518	10,805	105,000	1.00	5,518	10,805	105,000
Sub Gen - 330/132kV	91	Support for MV insulated cable and cable terminal	1,929	59	42,500	1.00	1,929	59	42,500
Sub Gen - 330/132kV	125	Substation service transformer	0	0	4,250,000	1.00	-	-	4,250,000
Sub Gen - 330kV	41	Substation Service Transformer	27,012	439	125,900	1.00	27,012	439	125,900
Sub Gen - 330kV	53	Substation automation	451,492	84,742	0	1.00	451,492	84,742	-
Sub Gen - 330kV	61	330kV Busbar Protection System	131,874	22,443	450,000	1.00	131,874	22,443	450,000
Sub Gen - 330kV	65	Data analysis station	81,037	1,628	1,500,000	1.00	81,037	1,628	1,500,000
Sub Gen - 330kV	66	Remote digital fault recorder	30,100	5,017	80,000	1.00	30,100	5,017	80,000
Sub Gen - 330kV	69	Remote digital fault locator	28,556	4,631	75,000	1.00	28,556	4,631	75,000
Sub Gen - 330kV	73	Automatic transfer switch	13,892	27,784	260,000	1.00	13,892	27,784	260,000
Sub Gen - 330kV	76	Distribution panel, 110 Vcc, 225 A - Type 1	20,993	41,908	378,000	1.00	20,993	41,908	378,000
Sub Gen - 330kV	77	Diesel generator set, 50 kw	15,293	6,522	495,000	1.00	15,293	6,522	495,000
Sub Gen - 330kV	79	Battery, 48 Vdc, 200 A-h	8,532	19,295	180,000	1.00	8,532	19,295	180,000
Sub Gen - 330kV	81	Battery, Charger, 48 Vcd, 60 A	5,518	10,805	105,000	1.00	5,518	10,805	105,000
Sub Gen - 330kV	91	Support for MV insulated cable and cable terminal	1,929	59	42,500	1.00	1,929	59	42,500
Sub Gen - 330kV	125	Foundation - Substation service transformer	0	0	4,250,000	1.00	-	-	4,250,000
Tx - 132/33kV 60MVA	36	Power transformer, 60 MVA, 132/34,5 kV	1,066,854	26,928	5,580,000	1.00	1,066,854	26,928	5,580,000
Tx - 132/33kV 60MVA	63	Protection panel for 132-33kV Transformer	53,958	10,728	450,000	1.00	53,958	10,728	450,000

Cost driver	NIPP ID	Description	C&F unit price (USD)	Erection unit price (USD)	LTE unit price (NGN)	Units per cost driver	C&F per cost driver (USD)	Erection per cost driver (USD)	LTE per cost driver (USD)
Tx - 132/33kV 60MVA	112	Busbar tubular 1-1/2”Ø, sch 40(for 1 transformer)	4,337	95	79,900	1.00	4,337	95	79,900
Tx - 132/33kV 60MVA	119	Foundation - 132 / 33 kV, 40/60MVA power transformer	0	0	5,576,000	1.00	-	-	5,576,000
Tx - 132/33kV 60MVA	124	Foundation - Oil separator for the 50 MVA transformer or shunt reactor	0	0	2,650,000	1.00	-	-	2,650,000
Tx - 330/132kV 150MVA	35	Power autotransformer, 150 MVA, 330/132/34,5 kV	2,204,253	42,981	15,780,000	1.00	2,204,253	42,981	15,780,000
Tx - 330/132kV 150MVA	39	34.5 kV earthing reactor	131,267	9,956	1,709,900	1.00	131,267	9,956	1,709,900
Tx - 330/132kV 150MVA	59	Protection panel for Autotransformer	54,524	9,962	1,000,000	1.00	54,524	9,962	1,000,000
Tx - 330/132kV 150MVA	111	Busbar tubular 1-1/2”Ø, sch 80(for 1 transformer)	5,875	126	107,500	1.00	5,875	126	107,500
Tx - 330/132kV 150MVA	118	Foundation - 330 / 132 kV, 150 MVA power autotransformer	0	0	11,765,000	1.00	-	-	11,765,000
Tx - 330/132kV 150MVA	123	Foundation - Oil separator for the 150 MVA autotransformer	0	0	2,950,000	1.00	-	-	2,950,000
Tx - 330/132kV 150MVA	134	Foundation - 34.5 kV earthing reactor	0	0	524,889	1.00	-	-	524,889
Tx - 330/132kV 300MVA	34	Power autotransformer, 300 MVA, 330/132 kV	2,794,628	58,347	17,500,000	1.00	2,794,628	58,347	17,500,000
Tx - 330/132kV 300MVA	39	34.5 kV earthing reactor	131,267	9,956	1,709,900	1.00	131,267	9,956	1,709,900
Tx - 330/132kV 300MVA	59	Protection panel for Autotransformer	54,524	9,962	1,000,000	1.00	54,524	9,962	1,000,000
Tx - 330/132kV 300MVA	111	Busbar tubular 1-1/2”Ø, sch 80(for 1 transformer)	5,875	126	107,500	1.00	5,875	126	107,500
Tx - 330/132kV 300MVA	117	Foundation - 330 / 132 kV, 300 MVA power autotransformer	0	0	19,300,000	1.00	-	-	19,300,000
Tx - 330/132kV 300MVA	122	Foundation - Oil separator for the 300 MVA autotransformer	0	0	3,250,000	1.00	-	-	3,250,000
Tx - 330/132kV 300MVA	134	Foundation - 34.5 kV earthing reactor	0	0	524,889	1.00	-	-	524,889

Annex 8: Staffing Estimates

TSP Estimates

Professional staff numbers	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Asset monitoring	15	15	15	15	15	15	15	15	15	15
New Build: Procurement, management and supervision	30	30	32	35	35	35	30	30	27	27
Refurbishment: Procurement, management and supervision	15	15	15	15	15	0	0	0	0	0
Maintenance: Procurement, management and supervision	75	75	80	80	80	85	85	85	90	90
Transmission protection	15	15	15	15	15	15	15	15	15	15
Standards and safety	5	5	5	5	5	5	5	5	5	5
Transmission planning	10	10	10	10	10	10	10	10	10	10
Stores and stock management	5	5	5	5	5	5	5	5	5	5
Billing and collections	12	12	12	12	12	12	12	12	12	12
Regulatory and Government interface	7	7	7	7	7	7	7	7	7	7
Public relations	7	7	7	7	7	7	7	7	7	7
Legal (in-house)	5	5	5	5	5	5	5	5	5	5
IT	10	10	10	10	10	10	10	10	10	10
Finance	25	25	25	25	25	25	25	25	25	25
HR	10	10	10	10	10	10	10	10	10	10
Central management	15	15	15	15	15	15	15	15	15	15
Professional staff numbers - Total	261	261	261	261	261	261	261	261	261	261
Support staff numbers - Total	131	131	131	131	131	131	131	131	131	131

SO Estimates

Control Rooms		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
No of regional control rooms		8	8	8	8	8	8	8	8	8	8
No of sub-regional control rooms		24	24	24	24	24	24	24	24	24	24
No of substation control rooms		50	53	56	59	62	65	68	71	74	77
	Staff per Control Room	Staff numbers									
Professional staff numbers		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
National Control Centre		49	49	49	49	49	49	49	49	49	49
Control staff		20	20	20	20	20	20	20	20	20	20
Operational planning		10	10	10	10	10	10	10	10	10	10
Monitoring and post event		5	5	5	5	5	5	5	5	5	5
SCADA management		5	5	5	5	5	5	5	5	5	5
Telecom management		5	5	5	5	5	5	5	5	5	5
Management		4	4	4	4	4	4	4	4	4	4
Regional control rooms		152	152	152	152	152	152	152	152	152	152
Control staff	12	96	96	96	96	96	96	96	96	96	96
OP, Monitoring and post event	3	24	24	24	24	24	24	24	24	24	24
SCADA and telecoms	2	16	16	16	16	16	16	16	16	16	16
Management	2	16	16	16	16	16	16	16	16	16	16
Sub-regional control rooms		216	216	216	216	216	216	216	216	216	216
Control staff	6	144	144	144	144	144	144	144	144	144	144
Day support	2	48	48	48	48	48	48	48	48	48	48
Management	1	24	24	24	24	24	24	24	24	24	24
Substation control rooms		200	212	224	236	248	260	272	284	296	308
Control staff	4	200	212	224	236	248	260	272	284	296	308

Head office		110	110	110	110	110	110	110	110	110	110
Telecom management		5	5	5	5	5	5	5	5	5	5
SCADA management		5	5	5	5	5	5	5	5	5	5
System Planning		10	10	10	10	10	10	10	10	10	10
System Protection		5	5	5	5	5	5	5	5	5	5
Ancillary service management and training of participants		10	10	10	10	10	10	10	10	10	10
Regulatory and Government interface		5	5	5	5	5	5	5	5	5	5
Public relations		2	2	2	2	2	2	2	2	2	2
Legal (in-house)		3	3	3	3	3	3	3	3	3	3
IT		20	20	20	20	20	20	20	20	20	20
Finance		10	10	10	10	10	10	10	10	10	10
HR		20	20	20	20	20	20	20	20	20	20
Management		15	15	15	15	15	15	15	15	15	15
Professional staff numbers - Total		**727**	**739**	**751**	**763**	**775**	**787**	**799**	**811**	**823**	**835**
Support staff numbers - Total		**364**	**370**	**376**	**382**	**388**	**394**	**400**	**406**	**412**	**418**

MO Estimates

Professional staff numbers	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Metering	10	10	10	10	10	10	10	10	10	10
Settlement	5	5	5	5	5	5	5	5	5	5
Treasury	10	10	10	10	10	10	10	10	10	10
Market Development	5	6	7	8	9	10	11	12	13	14
Regulatory and Government interface	5	5	6	6	7	7	8	8	9	9
Industry relations	5	5	6	6	7	7	8	8	9	9
Public relations	3	3	3	3	3	3	3	3	3	3
Legal (in-house)	3	3	3	3	3	3	3	3	3	3
IT	5	5	5	5	5	5	5	5	5	5
HR	3	3	3	3	3	3	3	3	3	3
Finance	5	5	5	5	5	5	5	5	5	5
Central Management	8	8	8	8	8	8	8	8	8	8
Professional staff numbers - Total	**67**	**68**	**71**	**72**	**75**	**76**	**79**	**80**	**83**	**84**
Support staff numbers - Total	**34**	**34**	**36**	**36**	**38**	**38**	**40**	**40**	**42**	**42**