TRANSMISSION COMPANY OF NIGERIA

INDEPENDENT SYSTEM OPERATOR (ISO)

Part 1

Generation Adequacy Report

Retrospective for year 2015

By

Market Operator

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Contents

Definitions of Terms and Acronyms

The acronyms and the main terms are defined below. More detailed explanations of the terms are given in section 2.

ANGC	Available Net Generation Capacity Represents the available capacity, as recorded in the Daily Operational Reports. It includes the values declared by the generation companies and takes planned and Forced Outages into consideration.
ANE	Available Net Energy Represents the electrical energy that is available from the power stations. It includes the capacity restrictions (as in ANGC) as well as energy constraints. It is typically expressed as an average power in MWh/h.
DISCO	Distribution companies
ENS	Energy Not Supplied
ENS_{Total}	Energy Not Supplied based on total demand
ENS_{UnG}	Energy Not Supplied based on unconstrained on-grid demand estimate
Forced Outage	Shutdown of equipment due to failure, normally initiated automatically by protection relay(s).
GGC	Active Gross Generation Capacity = installed generation capacity – capacity of units permanently not available
NGC	Net Generation Capacity = GGC – Auxiliary power of power plants – Power plant losses
OM	Operating Margin Difference between available generation, considering the generation constraints, and the actual level of peak generation.
Partial Collapse	Power system disturbances causing at least half of the load to be disconnected.
PTFP	Presidential Task Force on Power
RANGC	Reliably Available Net Generation Capacity Represents the ANGC that is achieved 99% of the time
RM	Remaining Capacity Margin, also called Remaining Margin Excess capacity of reliably available generation, taking into consideration generation constraints, operating reserves and the peak demand.
RM_{Total}	Remaining Capacity Margin based on the total peak demand

RM_{UnG}	Remaining Capacity Margin based on unconstrained on-grid peak demand
Transmission Constraints	In this report, transmission constraints represent failures in the transmission system, which lead to the generated power having to be reduced. The power reductions are reported, but not considered in the calculations. They are considered in the transmission adequacy report.

1. Introduction

Generation adequacy is a measure of whether the generation of electricity in a system meets the demand reliably.

The main objective of this report is to provide a retrospective analysis of the generation adequacy in the Nigerian power system for the year 2015.

This report further lists generation adequacy indices, which will be tracked in future years as a means of monitoring the development of electricity generation in the Nigerian power system.

Table 1 shows the installed generation capacity in the Nigerian power system to be some 13.0 GW. Table 2 shows the Active Gross Generation Capacity to be 10.3 GW. The difference is due to decommissioned and permanently derated generating units.

Table 1: Installed generation capacity

Power plant	Gas [MW]	Hydro [MW]	Total [MW]
AES GAS	288		288
AFAM IV-V (GAS)	804		804
AFAM VI GAS/STEAM	726		726
ALAOJI NIPP GAS	480		480
ASCO	110		110
DELTA	967		967
EGBIN STEAM	1320		1320
GEREGU GAS	414		414
GEREGU NIPP	434		434
IBOM	191		191
IHOVBOR NIPP	450		450
JEBBA HYDRO		570	570
KAINJI HYDRO		760	760
ODUKPANI NIPP	561		561
OKPAI GAS/STEAM	480		480
OLORUNSOGO GAS	335		335
OLORUNSOGO NIPP GAS	675		675
OMOKU	150		150
OMOTOSHO GAS	335		335
OMOTOSHO NIPP GAS	450		450
RIVERS IPP	191		191
SAPELE (STEAM)	900		900
SAPELE NIPP	450		450
SHIRORO HYDRO		600	600
TRANS-AMADI	75		75
GBARAIN	225		225
PARAS	60		60
Total in MW	**11071**	**1930**	**13001**

Table 2: Active Gross Generation Capacity

Power plant	Gas [MW]	Hydro [MW]	Total [MW]
AES GAS	288		288
AFAM IV-V (GAS)	150		150
AFAM VI GAS/STEAM	650		650
ALAOJI NIPP GAS	480		480
ASCO	55		55
DELTA	625		625
EGBIN STEAM	1320		1320
GEREGU GAS	414		414
GEREGU NIPP	434		434
IBOM	115		115
IHOVBOR NIPP	450		450
JEBBA HYDRO		570	570
KAINJI HYDRO		500	500
ODUKPANI NIPP	600		600
OKPAI GAS/STEAM	480		480
OLORUNSOGO GAS	336		336
OLORUNSOGO NIPP GAS	600		600
OMOKU	0		0
OMOTOSHO GAS	308		308
OMOTOSHO NIPP GAS	480		480
RIVERS IPP	160		160
SAPELE (STEAM)	480		480
SAPELE NIPP	240		240
SHIRORO HYDRO		600	600
TRANS-AMADI	0		0
GBARAIN	0		0
PARAS	0		0
Total in MW	**8665**	**1670**	**10335**

2. Performance Indices and their Derivation

2.1. Overview

The generation adequacy was analysed by studying the capability of the generating stations to

a. adequately supply the load
b. provide the required ancillary services.

Additional information about how the performance of the generating stations was assessed is described below. The capability of the generating stations to supply the load is discussed under the section "Power and Energy", while their capability to provide ancillary services is discussed under the section "Ancillary Services".

2.2. Power and Energy

2.2.1. Available Net Generation Capacity

Available Net Generation Capacity without constraints, ANGC

The Active Gross Generation Capacity, GGC, is shown in Table 2. The Net Generation Capacity (NGC) represents the GGC less the auxiliary power:

ANGC represents the NGC less the capacity that is unavailable due to forced and planned outages. The Available Net Generation Capacity (ANGC) was obtained from the Daily Operational Reports [1], where it is titled "generation capability" [1], less the auxiliary power and losses. The auxiliary power was calculated for each power station based on an analysis of the generated and sent-out energy values provided in the broadcast reports. The values corresponding to the morning peak were used since much more detailed information is available for the morning peak than for the evening peak.

ANGC = NGC – Capability of units unavailable due to planned and Forced Outages
– Capability of units not yet declared available for generation

= (Generation capability from Daily Operational Reports [1] *– Capability of units not yet declared available for generation from Daily Operational Reports* [1]*, the latter reduced by auxiliary power and power station losses)*

The value that the ANGC had for at least 99% of the time was extracted as a measure of the load that can be supplied with that level of confidence. This value is known as the Reliably Available Net Generation Capability, RANGC.

RANGC = Minimum value of ANGC that is achieved at least 99% of the time

Available Net Energy, ANE

Water and gas constraints reduce the amount of generation that is available to the transmission system. Water constraints limit the available energy, rather than the power, since the network operator may decide how to use the available water. The gas constraints may have an impact on both power and energy, but it is assumed that predominantly the energy is affected.

Monthly values of the Available Net Energy (ANE) were obtained by adding the daily available energy values for each month, which were calculated as follows:

*ANE = (ANGC * Duration) – Energy not available due to fuel and water constraints*

= (ANGC – Unutilised generation capability due to fuel and water constraints from Daily Operational Reports [1]*, reduced by the auxiliary power and power station losses) * Duration*

Average power values were calculated by dividing the monthly ANE values by the number of hours in the corresponding months.

The relative importance of these fuel and water constraints was assessed by comparing their average values. The calculation of average values implicitly assumes that the daily values apply for equal time periods (e.g. the entire day), which is not necessarily true. This simplification has been accepted in the analysis.

2.2.2. Energy Not Supplied

Energy Not Supplied based on total demand

The Energy Not Supplied based on end customer demand, ENS_{CUST} was calculated as the difference between the energy sent out, as obtained from [1], and the energy demand. Therefore, it does not consider the reasons for the failure to supply the energy. It is a measure of the level of the expansion that is required to satisfy the needs of all customers, including, but not limited to, generation expansion. However, this would not consider the ability of the end customers to pay for the supply of electricity.

$$ENS_{CUST} = \text{Total energy demand - Energy sent out}$$

In this calculation, the energy demand does not consider any generation, transmission or distribution constraints, i.e. it represents the potential demand. This demand could not be derived from the load nominations by the distribution companies [2], since that information already includes the generation constraints. Therefore, the energy demand was estimated based on the estimated peak demand, as obtained from [1], and an assumed load profile. According to this load profile, the average power is 75% of the peak power (this is called the load factor).

Energy Not Supplied based on unconstrained on-grid demand estimate

The Energy Not Supplied based on distribution company capability, ENS_{DISCO}, was calculated as the difference between the energy sent out, as obtained from [1], and the energy that the distribution companies could draw from the transmission grid, based on their capability and the losses in the transmission and distribution grids. ENS_{DISCO} can be used to estimate the required expansion in generation if the DISCOs operate at maximum capacity.

$$ENS_{UnG} = \text{Unconstrained on-grid energy demand - Energy sent out}$$

The demand has been calculated from the distribution capability, which is known to be lower than the true peak demand. It has been assumed that the distribution capability has not changed significantly from the values reported by The Presidency – Federal Republic of Nigeria, in 2011 [3].

2.2.3. Energy Management

The electricity supply in Nigeria is affected significantly by energy constraints. Therefore, a performance index that reflects the utilisation of the available energy is of interest. If the utilised energy is significantly lower than the available energy whilst the Energy Not Supplied is positive, then this would represent a poor utilisation of resources in the electricity industry.

The actual monthly energy obtained from generation (i.e. the utilised energy), was compared to the available energy, where the latter takes into consideration generation constraints, Transmission Constraints and power that must be kept as spinning reserve. The annual percentage energy utilised was calculated.

2.2.4. Remaining Capacity Margin

Remaining Capacity Margin based on total peak demand

The Remaining Capacity Margin, RM, has been calculated as follows:

RM_{Total} = *RANGC – allowance for operating reserves – total peak demand*

Remaining Capacity Margin based on unconstrained on-grid peak demand

The Remaining Capacity Margin, RM, has been calculated as follows:

RM_{UnG} = *RANGC – allowance for operating reserves – Unconstrained peak demand*

2.3. Ancillary Services and System Stability

2.3.1. Frequency Regulation

General

The capability of the generation stations to regulate the frequency was assessed by comparing the highest and lowest frequencies per day, as obtained from [1], to the statutory limits specified in [4]. In addition, the performance of frequency regulation was assessed from the frequency response during one day.

Generation Reduction due to frequency problems

The reduction in generation due to frequency problems was obtained from [1]. The result was used as part of the assessment of the quality of frequency regulation. No average values were calculated, since it cannot be assumed that the recorded generation reductions apply throughout the entire day.

2.3.2. Operating Reserve Management

Spinning Reserves

Firstly, the capability of generators to reduce their output in response to high frequencies (emergency) was assessed. Secondly the capability to provide primary frequency support under normal operating conditions, i.e. to provide primary frequency support, was assessed.

The power stations that can provide spinning reserve, and specifically the ability to increase their output in response to frequency drops, were identified using information provided in the Daily Operational Reports [1].

The actual spinning reserve that was available on each day, as obtained from the Daily Operational Reports [1], was compared with the target value of 220 MW. The target value corresponds to the largest generating unit, in accordance with the requirements in the grid code [4]. The number of days during which this target value was achieved was derived.

Operating Margin

The Operating Margin, OM, was calculated as the difference between the available generation, ANGC, and the actual generation. The average value was calculated. The OM has been used to assess how well the reserves were managed in 2015.

2.3.3. Voltage Regulation

The capability of generators to provide voltage regulation was assessed by determining which generation stations und units have fully operational automatic voltage regulators. Secondly, the type and operational status of the tap changers of all generation stations and units were identified.

2.3.4. Black Start Capability

The generating stations capable of starting without requiring an external power source were identified from the Daily Operational Reports [1]. In addition, the availability of the black starting functionality was determined by finding the number of days on which at least four generating stations were available for black starting.

2.3.5. System Collapses

The number of partial and total collapses in 2015 and in past years was obtained from the Daily Operational Reports [1]. The development of these two numbers of the past seven years has been reported.

3. Power and Energy

3.1. Available Generation Capacity

3.1.1. Available Net Generation Capacity, ANGC

Figure 1 shows the Available Net Generation Capacity (ANGC), prior to consideration of generation constraints, and compares this to the installed capacity.

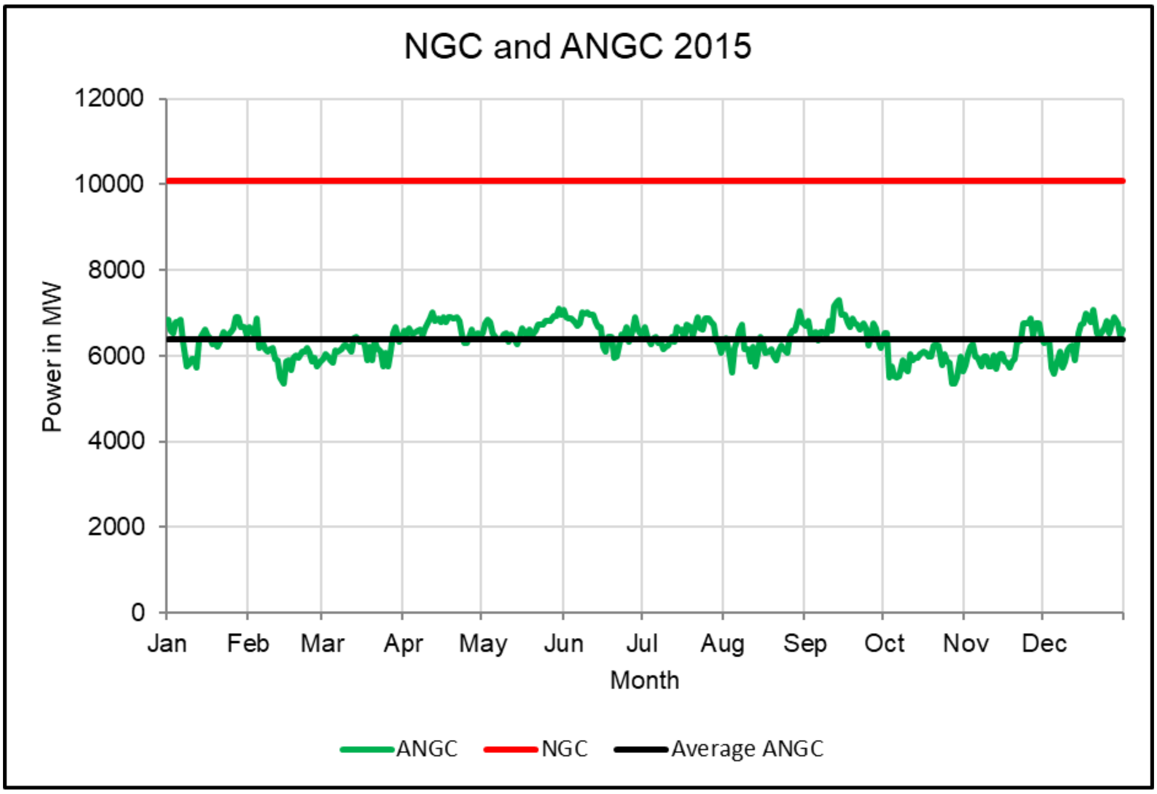


Figure 1: Installed generation capacity and ANGC

A duration curve of the ANGC is included in Annex 1. This was used to derive the RANGC values, and hence the maximum load that can be supplied at different levels of confidence.

Table 3 provides the average ANGC as well as the maximum load that could be supplied at 99% confidence levels.

Table 3: Summary of ANGC values

Description	Value	
NGC	10089	MW
Average ANGC	6376	MW
Average ANGC / NGC	63	%
RANGC	5495	MW
Allowance for operating reserves	220	MW
Maximum load at 99% confidence level	5275	MW

3.1.2. Available Net Energy

Figure 2 shows the fuel constraints, as reported on a daily basis [1].

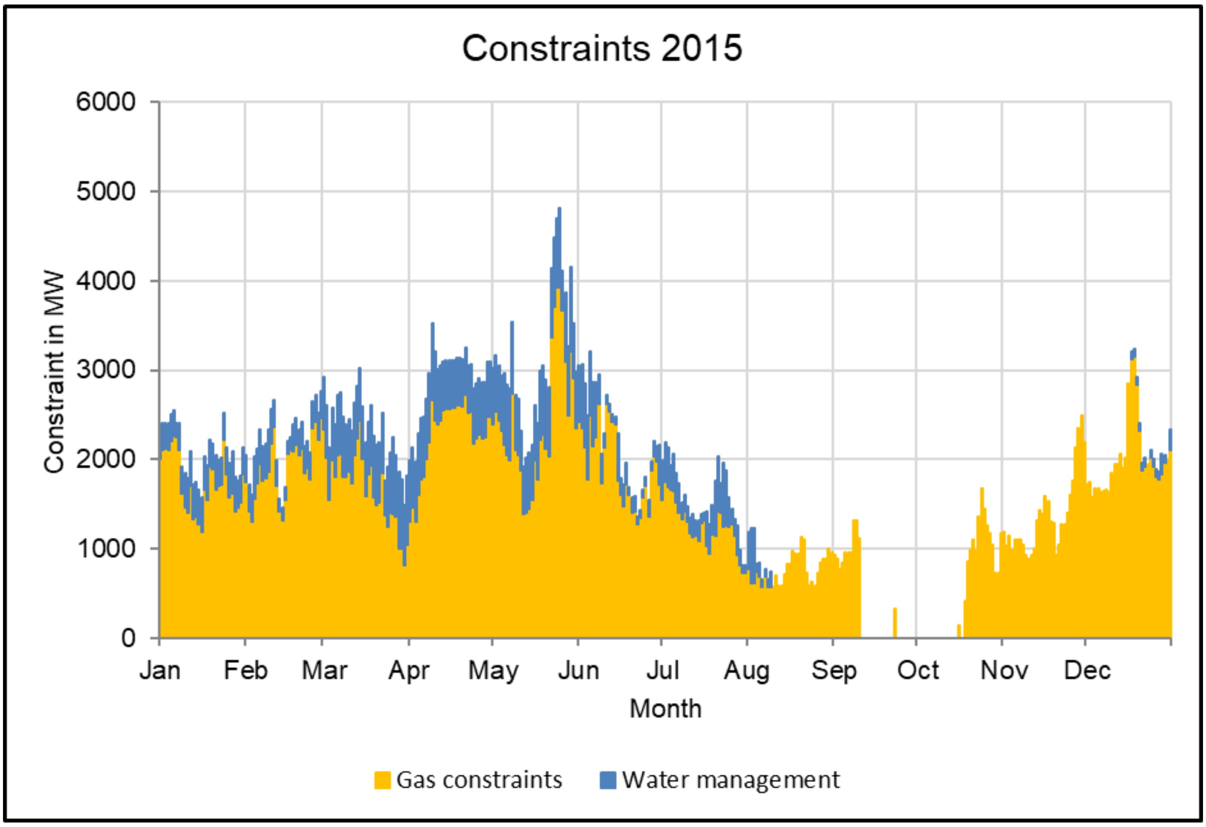


Figure 2: Daily fuel constraints

The following table shows the average values of the generation constraints. Gas shortages accounted for more than half of the total constraints in 2015.

Table 4: Average values of constraints

Description	Value	
Gas shortages	1512	MWh/h
Water management	277	MWh/h
Total	1789	MWh/h

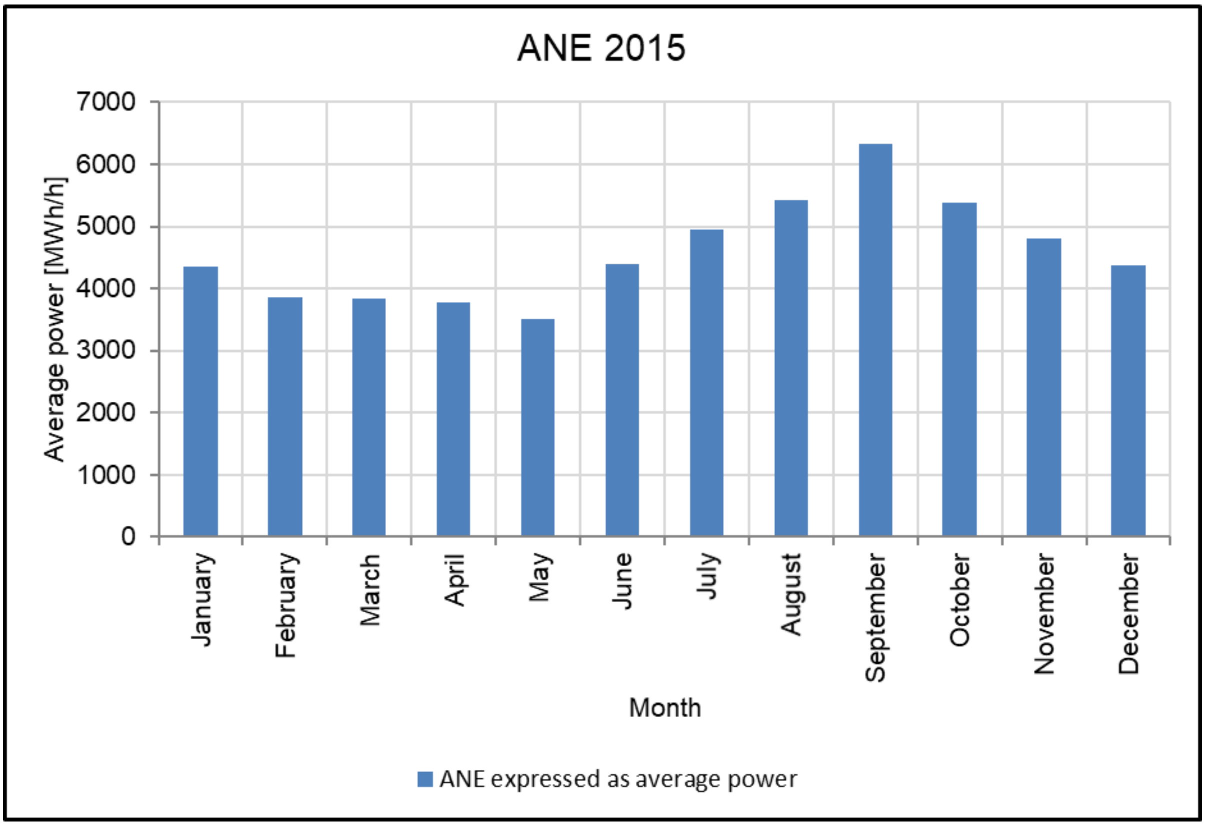


Figure 3: Available Net Energy, expressed as average power

Table 5 shows the average ANE for all months of 2015.

Table 5: Total and average ANE values

Description	Average energy
ANE per year	40.2 TWh
Average ANE, expressed as power	4587 MWh/h

3.2. Energy Not Supplied

3.2.1. Energy Not Supplied Based on Total Demand

Table 6 shows the Energy Not Supplied, based on the total demand. The latter is calculated from the total peak demand and an assumed load factor.

Table 6: Total demand

Capability	Demand	
Peak demand at interface to generation	14630	MW
Load factor	0.75	
Average demand	**10972**	**MWh/h**
Energy demand	**96.12**	**TWh**

The following table shows the energy that was not supplied to end customers. The reasons include constraints in all sectors of the power system, namely generation, transmission and distribution.

Table 7: Energy Not Supplied based on total demand

Description	Energy	Average power
Energy demand	96.1 TWh	10972 MWh/h
Actual Energy generated	31.6 TWh	3604 MWh/h
Actual Energy sent out by generators	30.9 TWh	3529 MWh/h
Energy Not Supplied	65.2 TWh	7443 MWh/h

3.2.2. Energy Not Supplied Based on Unconstrained On-grid Demand

Table 8 shows the unconstrained on-grid demand of the distribution companies and the estimated demands of the neighbouring countries. The estimated transmission losses are added to derive the demand at interface to the generating stations. An assumed load factor is applied to derive the average power demand, and from that the energy demand. The demands of the distribution companies were obtained from the DISCO Stress Test Report [5].

Table 8: Unconstrained on-grid demand

Capability	Demand [MW]
Distribution companies	
Abuja	711
Benin	790
Eko	723
Enugu	594
Ibadan	868
Ikeja	894
Jos	353
Kaduna	576
Kano	430
Port Harcourt	648
Yola	210
Total DISCO peak demand	6797
International connections	
Benin	200
Niger	95
Total international connection peak demand	295
Peak demand at interface to customers	7092
Peak demand at interface to generation	**7650**
Estimated load factor	0.75
Average demand	**5738MWh/h**
Energy demand	**50.26TWh**

Transmission losses were considered in the calculation and were estimated at 7.3% of the distribution capability. The following table shows the energy that was not supplied to the distribution companies and the international connections.

Table 9: Energy Not Supplied based on unconstrained on-grid demand

Description	Energy	Average power
Energy demand	50.3 TWh	5738 MWh/h
Actual Energy generated	31.6 TWh	3604 MWh/h
Actual Energy sent out by generators	30.9 TWh	3529 MWh/h
Energy Not Supplied	19.3 TWh	2208 MWh/h

3.2.3. Energy Management

Figure 4 shows the available energy after allocation of 220MW of spinning reserve and the actual energy sent out by generation, both expressed as average power values.

The figure shows that, in most months of 2015, there was inadequate utilisation of the available energy. Over the course of the year, only 75% of the available energy was utilised. One reason for this is the poor frequency regulation, which has led to extensive load shedding (see also Generation Adequacy Retrospective Report).

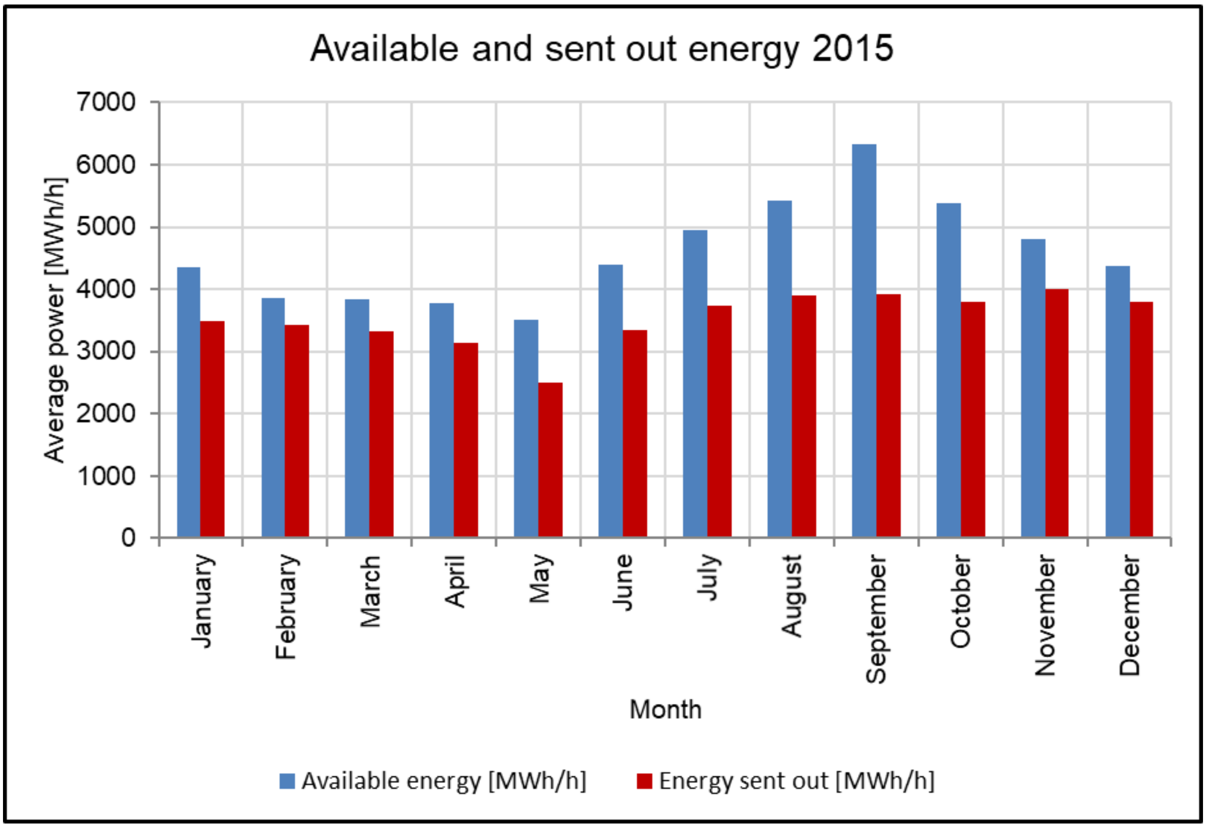


Figure 4: Potential energy demand, available energy supply and actual energy consumption

Table 10: Utilisation of electrical energy

Quantity	**Energy [TWh]**	**Average power [MWh/h]**
Available energy	40.2	4587
Sent out	30.9	3529
Percentage utilisation		**77%**

3.3. Remaining Capacity Margin

3.3.1. Remaining Capacity Margin Based on Total Demand

The following table shows the Remaining Capacity Margin when the demand is assumed to have its peak value, as per Table 6. At a 99% confidence level the generation capacity was insufficient and the Remaining Capacity Margin negative.

Table 11: Remaining Capacity Margin based on total peak demand

Description	Value	
RANGC	5495	MW
Allowance for operating reserves	220	MW
Peak demand on generation	14630	MW
Remaining Capacity Margin, RM	-9355	MW

3.3.2. Remaining Capacity Margin Based on Unconstrained On-grid Demand

The following table shows the Remaining Capacity Margin based on the unconstrained on-grid demand in Table 8. The negative value indicates that there was insufficient available generation capacity to meet the demand and operate the system reliably.

Table 12: Remaining Capacity Margin based on unconstrained on-grid demand

Description	Value	
RANGC	5495	MW
Allowance for operating reserves	220	MW
Peak demand on generation	7650	MW
Remaining Capacity Margin, RM	-2375	MW

4. Ancillary Services and System Stability

4.1. Frequency Regulation

4.1.1. General

Figure 5 shows the minimum and maximum frequencies throughout 2015 and Figure 6 shows the corresponding duration curve.

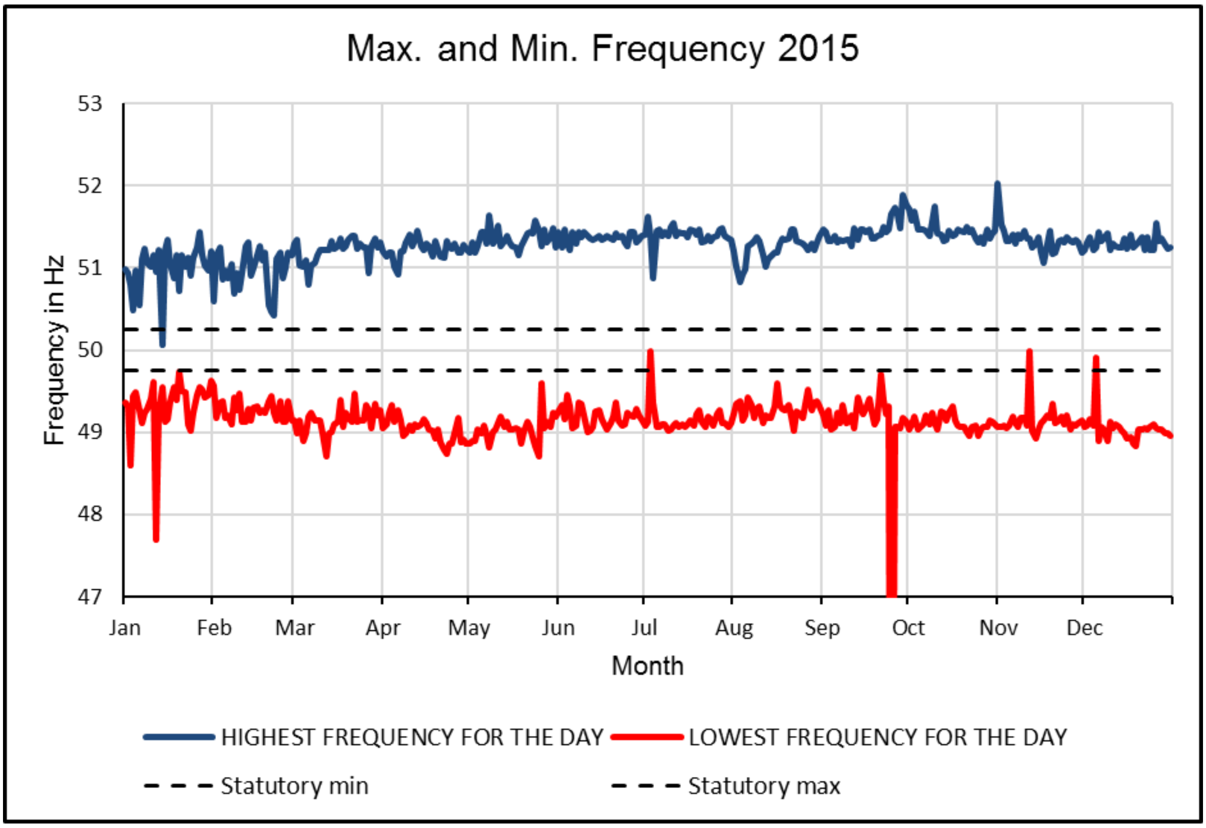


Figure 5 – Maximum and minimum frequencies

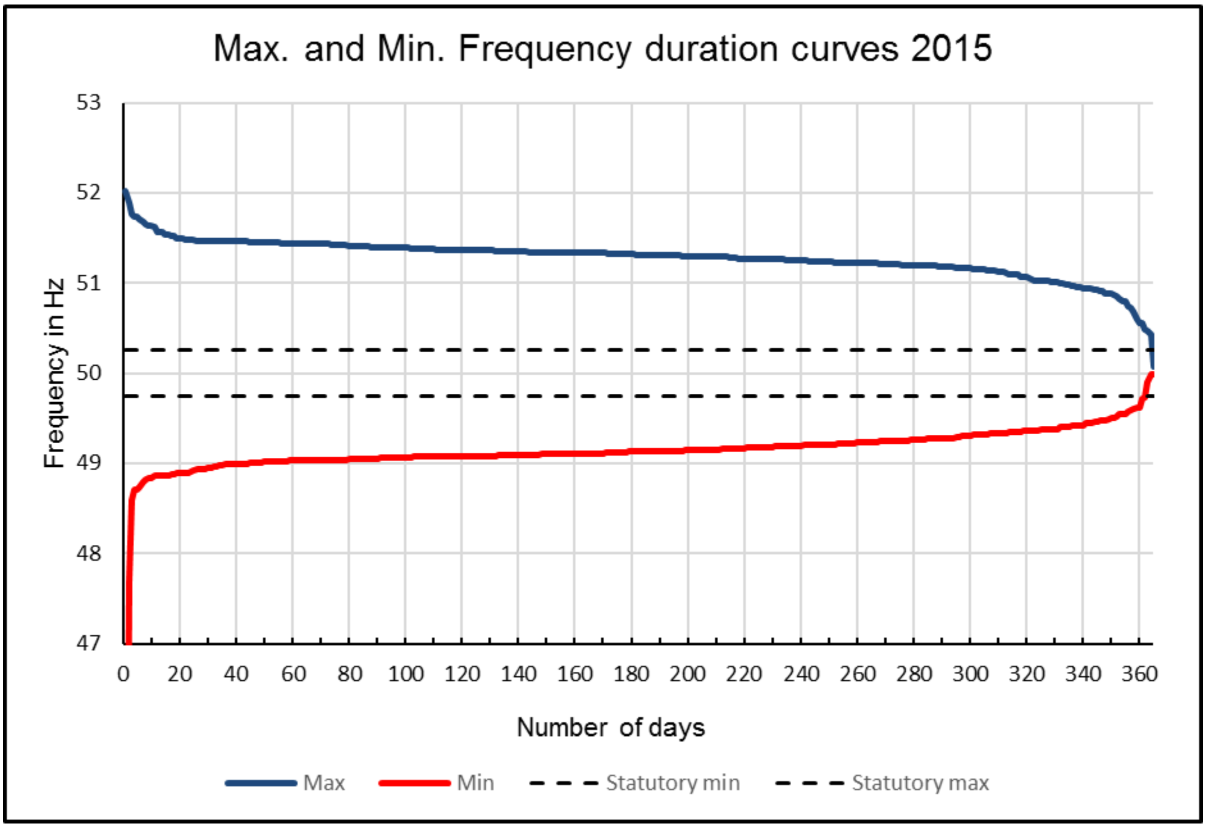


Figure 6 – Duration curve of maximum and minimum frequencies

Table 13 shows the number of days that the frequency remained within the statutory limits of 49.75 – 50.25 Hz [4].

Table 13: Number of days within statutory frequency limits

Description	Value
Number of days on which frequency within statutory limits	0 day(s)

The poor frequency regulation is attributed to the failure of the generators to provide primary frequency response. This is confirmed by the frequency distribution[1], as shown in Figure 7, as well as the frequency response of one day, as shown in Figure 8.

[1] *The curve has been plotted using frequencies at one-minute intervals during the months Jan., Feb., Apr., Jun., Jul., Aug., Dec.*

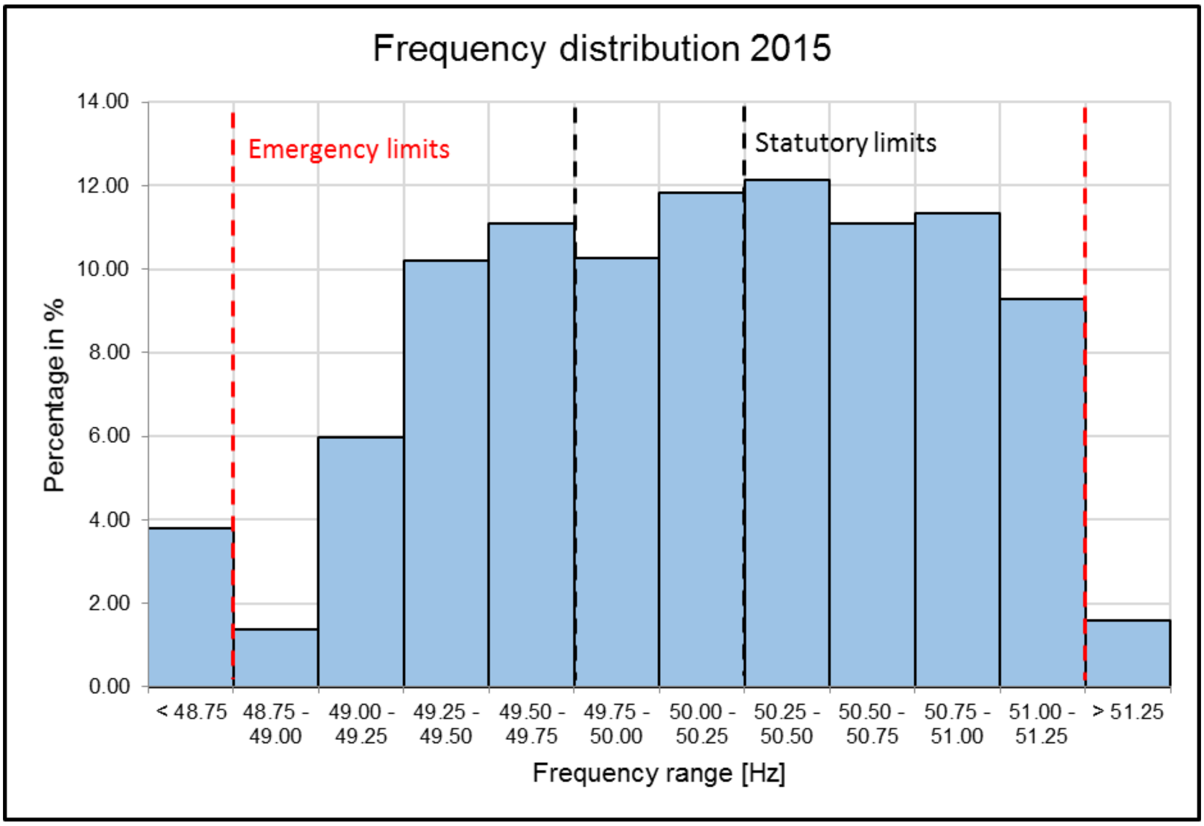


Figure 7 –Frequency distribution

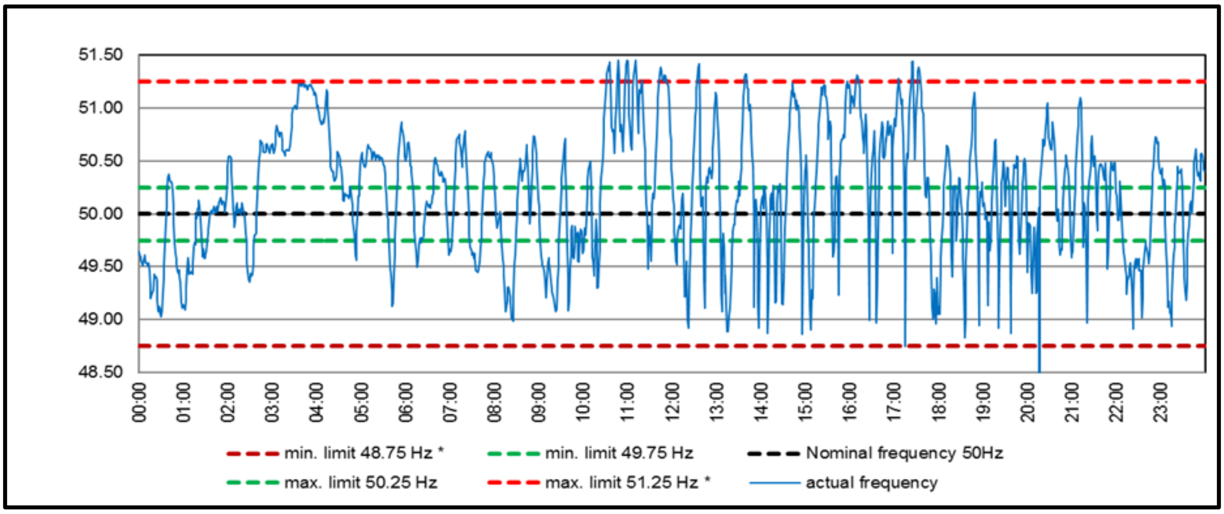


Figure 8 – Example of frequency over the course of one day

4.1.2. Generation Reduction Due to Frequency Problems

Figure 9 shows the reduction in generation that was required because of frequency problems, such as load rejection followed by over-frequency and generation reduction. The corresponding duration curve is shown in Annex 2 – Unutilised Generation Capacity. The results show that on 100 days more than 500 MW was temporarily not supplied due to frequency problems. This confirms the existence and importance of the frequency regulation problems.

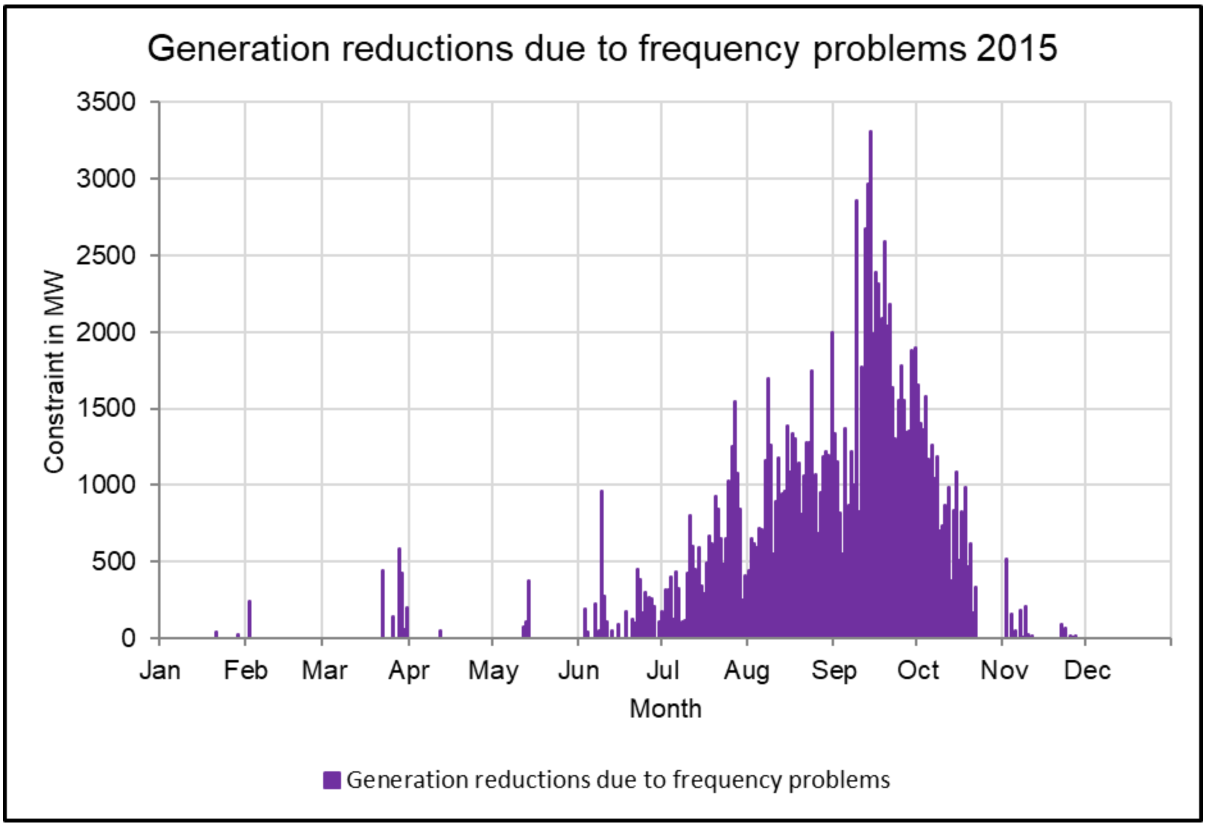


Figure 9 –Generation reduction due to high frequencies

4.2. Operating Reserve Management

4.2.1. Spinning Reserves

At the time of writing this report there was no information available about which generating stations do / do not provide downward regulation following an increase in the power system frequency.

The following table lists the generating stations that could be contracted for spinning reserves. It is presently not known which of these stations have fully functioning governor controls.

Table 14: Power stations that can be contracted for spinning reserves

Power station	Maximum spinning reserve capacity [MW]	Fully functioning governor controls
Egbin	250	Unknown
Kainji	0	Unknown
Delta	120	Unknown
Olorunsogo NIPP	200	Unknown
Geregu NIPP	110	Unknown
Omotosho NIPP	160	Unknown

Figure 10 shows the target value of spinning reserve (220 MW) and the actual values throughout 2015.

The actual values of spinning reserves are represented as a duration curve in Annex 3 – Operating Reserves. The number of days on which at least the target value was met is as shown below.

Table 15: Number of days on which target value of spinning reserves was met

Description	Value
Number of days on which target spinning reserves met	4 day(s)

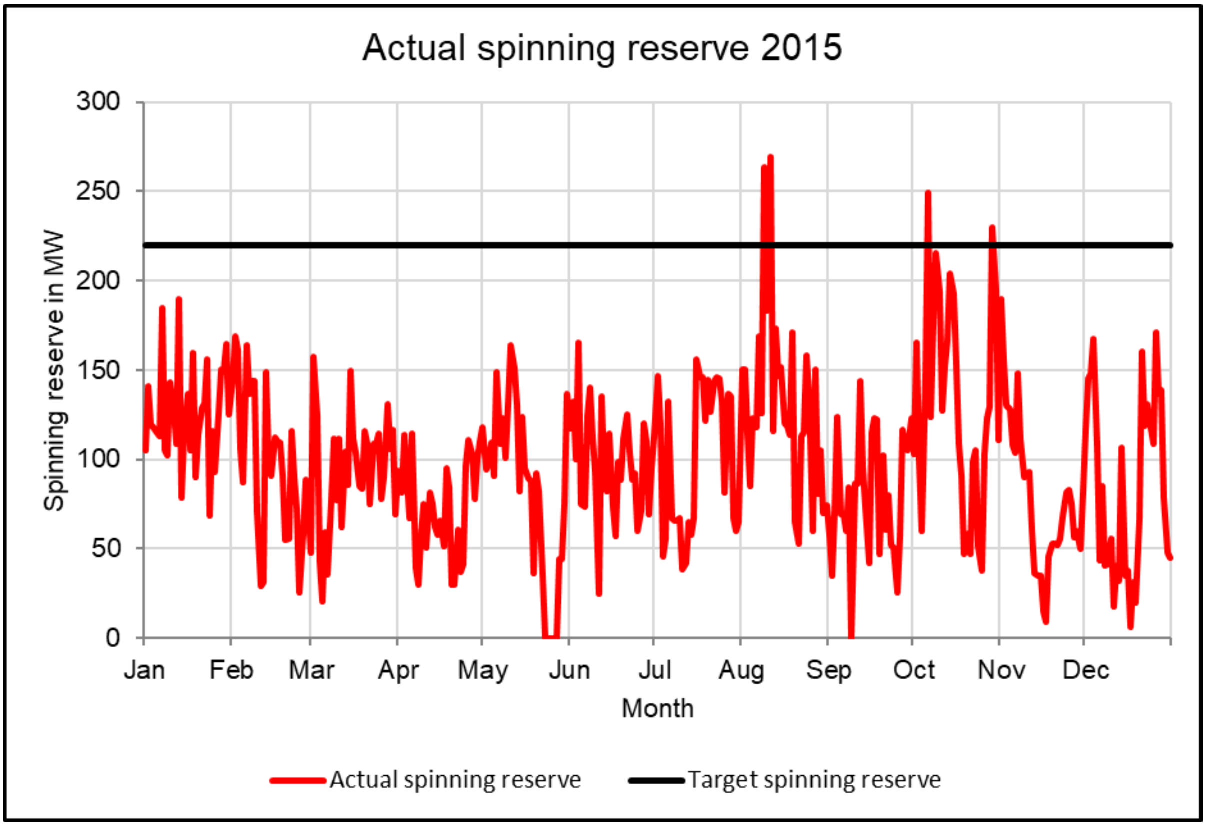


Figure 10 –Target and actual spinning reserve

4.2.2. Operating Margin

Figure 11 shows the ANGC and the actual peak generation for 2015. The difference between these two, less the Transmission Constraints, represents the Operating Margin, which is shown in Figure 12. The average value was as follows:

Table 16: Average Operating Margin

Description	Value
Average Operating Margin	2585 MW

The average value exceeded the required reserves, indicating that it would have been possible to supply more load during 2015.

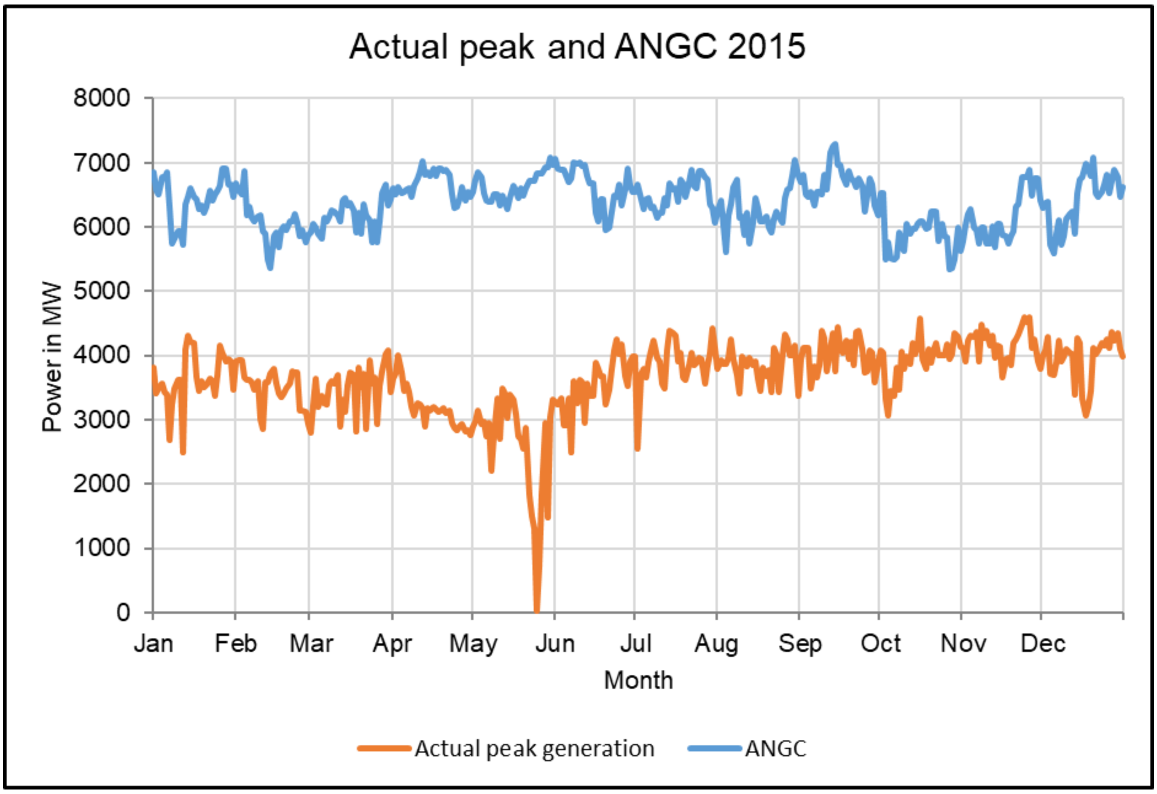


Figure 11 –Actual and available peak generation

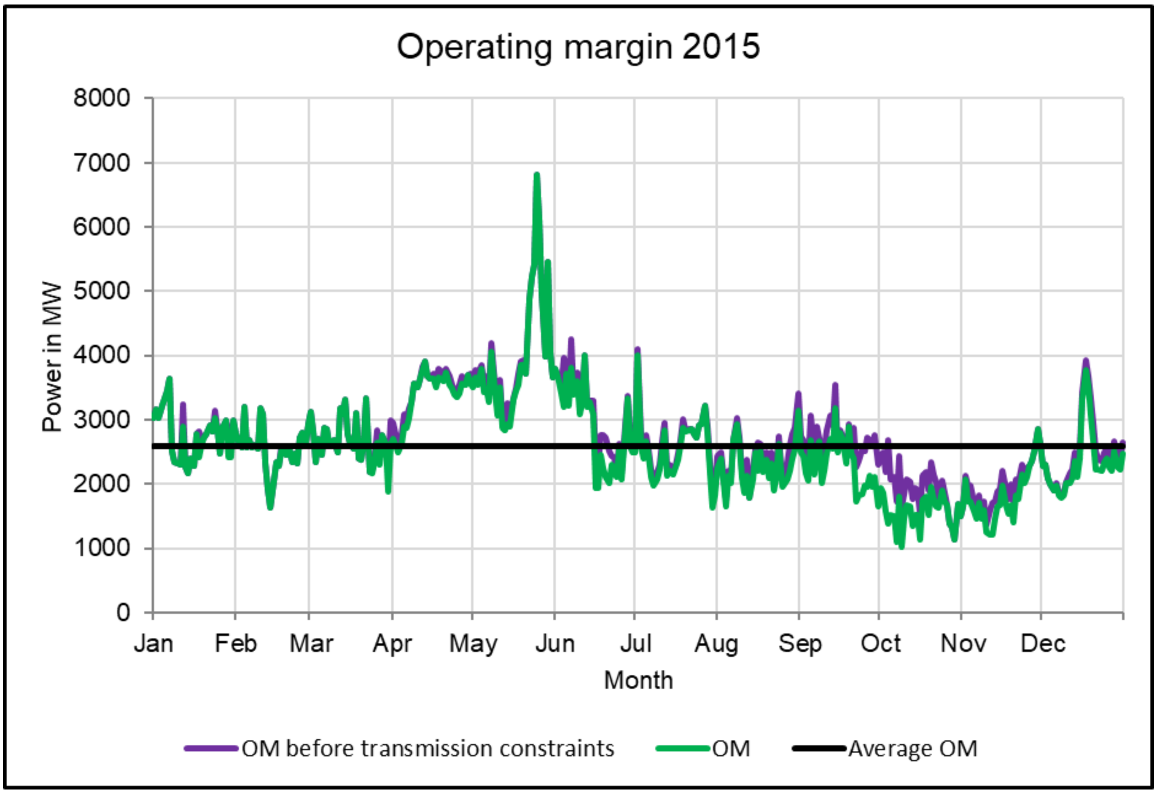


Figure 12 –Actual Operating Margin

4.3. Voltage Regulation

No information about the type and performance of the generator voltage regulation and the generator transformer tap changers was available at the time of writing this report.

4.4. Black Start Capability

The following generation stations are capable of black starting:

- Delta
- Shiroro
- Kainji
- Egbin

Presently, only Delta power station is considered to provide the black start service reliably.

The performance of the generating stations during 2015 with respect to black start capability is summarised as follows:

Table 17: Availability of black start stations

Description	Value
Days all four stations available for black start	207 Days
Number of stations proven to provide black start function reliably	1

4.5. System Collapses

Table 18 summarises the partial and total system collapses that occurred in 2015, and Table 19 shows the development in the number of collapses in recent years.

The number of collapses is high by international standards, but the trend over recent years shows an improvement.

Table 18: Summary of system collapses in 2015

Month	Partial Collapses	Total Collapses
January		1
February		
March	1	1
April		
May	2	2
June		
July		1
August		
September		
October	1	
November		1
December		
Total	**4**	**6**

Table 19: Summary of system collapses in recent years

Year	Partial Collapses	Total Collapses
2009	20	19
2010	20	22
2011	6	13
2012	8	16
2013	2	22
2014	4	9
2015	4	6

5. Summary of Performance Indices

Table 20: Summary of generation adequacy performance indicators

Performance indicator	2014	2015
Generation capacity before constraints		
Net generation capacity, NGC		10089 MW
Average net generation capacity, ANGC		6376 MW
Average as percentage of NGC	-	63 %
Maximum load at 99% confidence level	-	5275 MW
Energy Not Supplied (expressed as average power)		
Based on TCN’s demand estimate	-	7443 MWh/h
Based on unconstrained on-grid demand estimate (PTFT)	-	2208 MWh/h
Utilisation of electrical energy		75%
Remaining Capacity Margin (99% confidence level)		
Based on TCN’s demand estimate	-	-9355 MW
Based on unconstrained on-grid demand estimate (PTFT)	-	-2375 MW
Frequency regulation		
Number of days statutory frequency limits not exceeded	-	0
Number of days that target spinning reserve met	-	4
All units provide high frequency response	-	No
Primary frequency support active on units that are required	-	No
Voltage regulation		
Percentage of power plants with fully operational AVRs	-	Unknown
Percentage of power plants with fully operational on-load tap changers	-	Unknown
Black start capability		
Days with availability of at least four stations	-	207
Number of stations proven to provide black start function reliably	-	1
System collapses		
Number of Partial Collapses	-	4
Number of total collapses	-	6

6. Future Development of this Report

Some ideas for the future improvement of this report are as follows:

1. A load curve can be added to improve the accuracy of the Energy Not Supplied to end customers. At the time of writing this report, such a curve is not known since the actual load is limited by constraints in the generation, transmission and distribution systems.
2. In future, additional performance indices could be added, such as the loss of load probability (LOLP) and the loss of load expectancy (LOLE). These indices are relevant for power systems with adequate generation.
3. The calculation of Remaining Capacity Margin should, in future, be based on the primary and secondary frequency reserves, not only the primary frequency reserves. This modification to the calculation should be made once the Remaining Capacity Margin becomes positive.
4. In future, generation data corresponding the evening peak could be used instead of, or in addition to, information corresponding to the morning peak. This will become relevant when the load profile becomes more pronounced.

References

[1] National Control Center, “Daily Operational Reports 2015,” Osogbo, 2015.

[2] Transmission Company of Nigeria, “DISCO Load Nominations,” 2015.

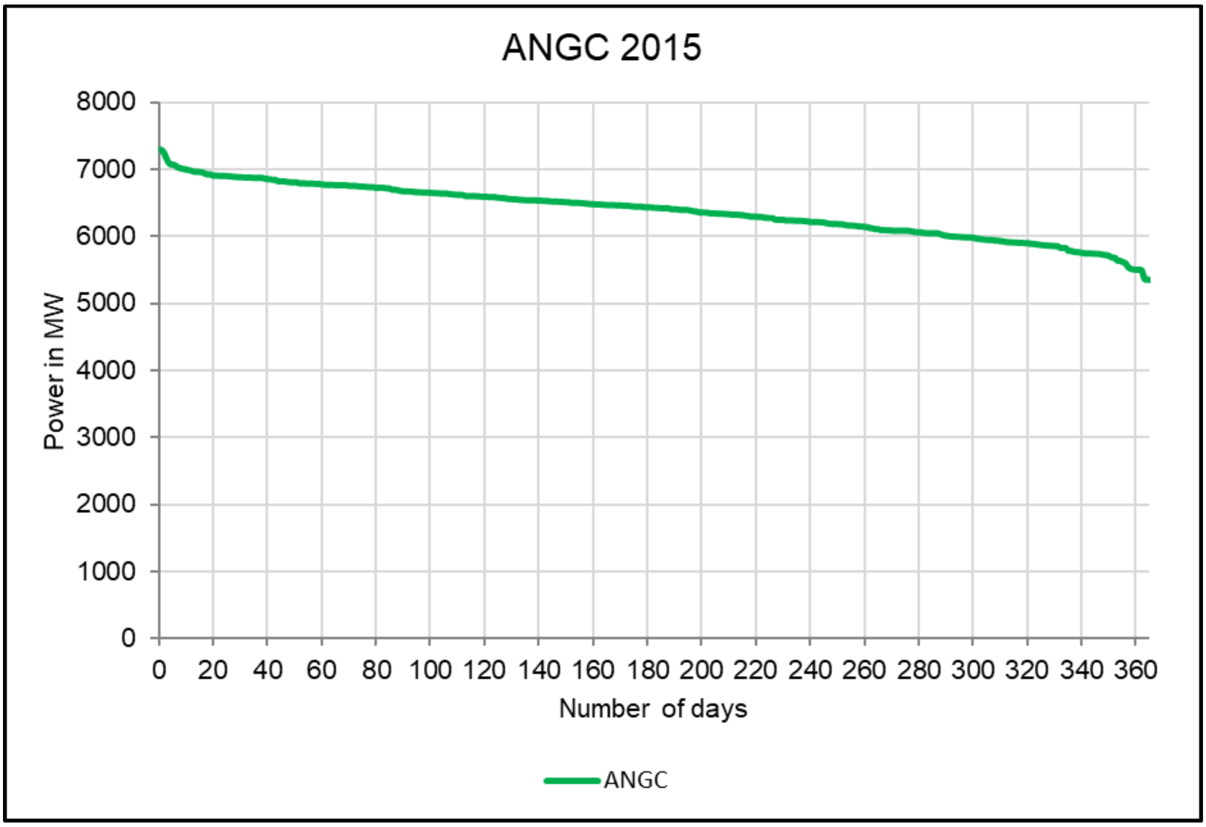
[3] Federal Government of Nigeria, “Nigeria Power Baseline Report,” Nigeria, August 2015.

[4] Nigerian Electricity Regulatory Commission, “Grid Code,” 24 12 2014. [Online]. Available: http://www.nercng.org/index.php/nerc-documents/func-startdown/305/. [Accessed 07 10 2016].

[5] The Presidential Task Force on Power, “PTFP Distribution Stress Test Report,” 2015.

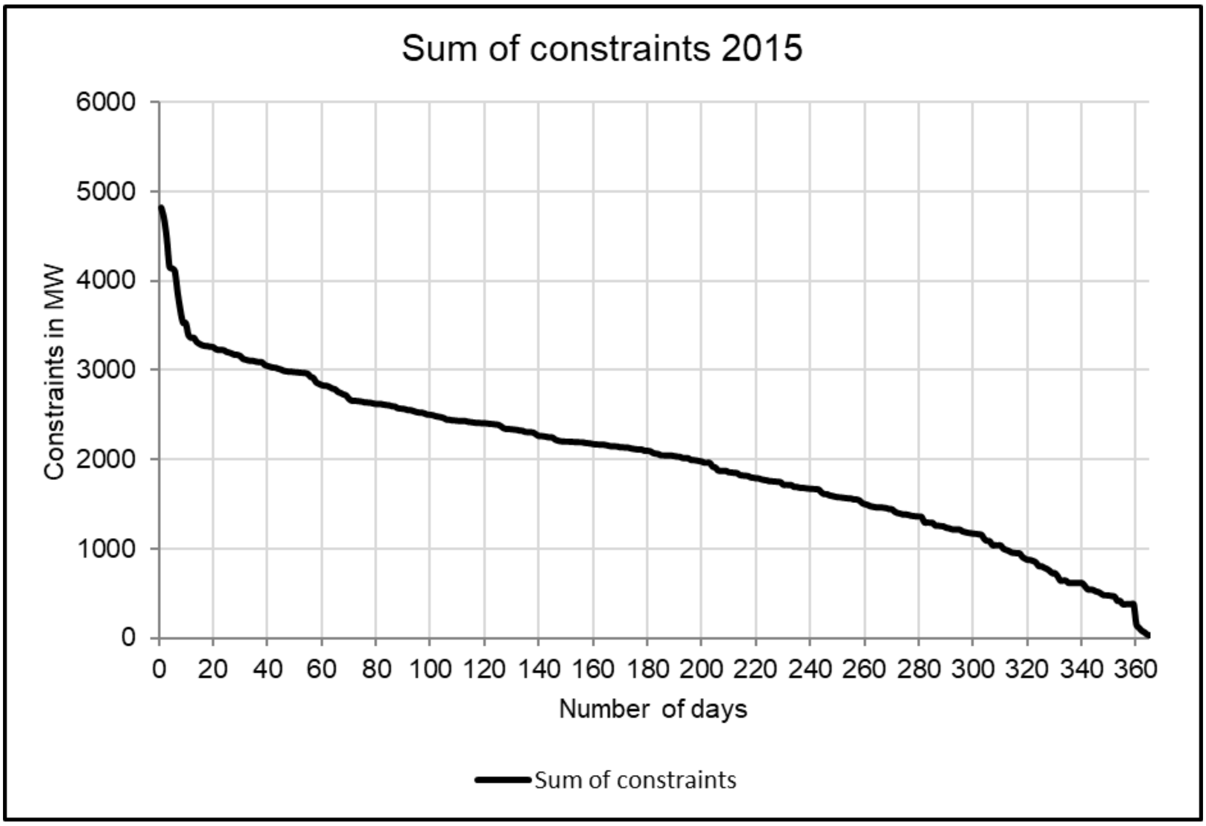
[6] The Presidency Federal Republic of Nigeria - Presidential Task Force, “Power sector outlook in Nigeria: Government's Renewed Priorities; Prof. Nnaji,” June 2011.

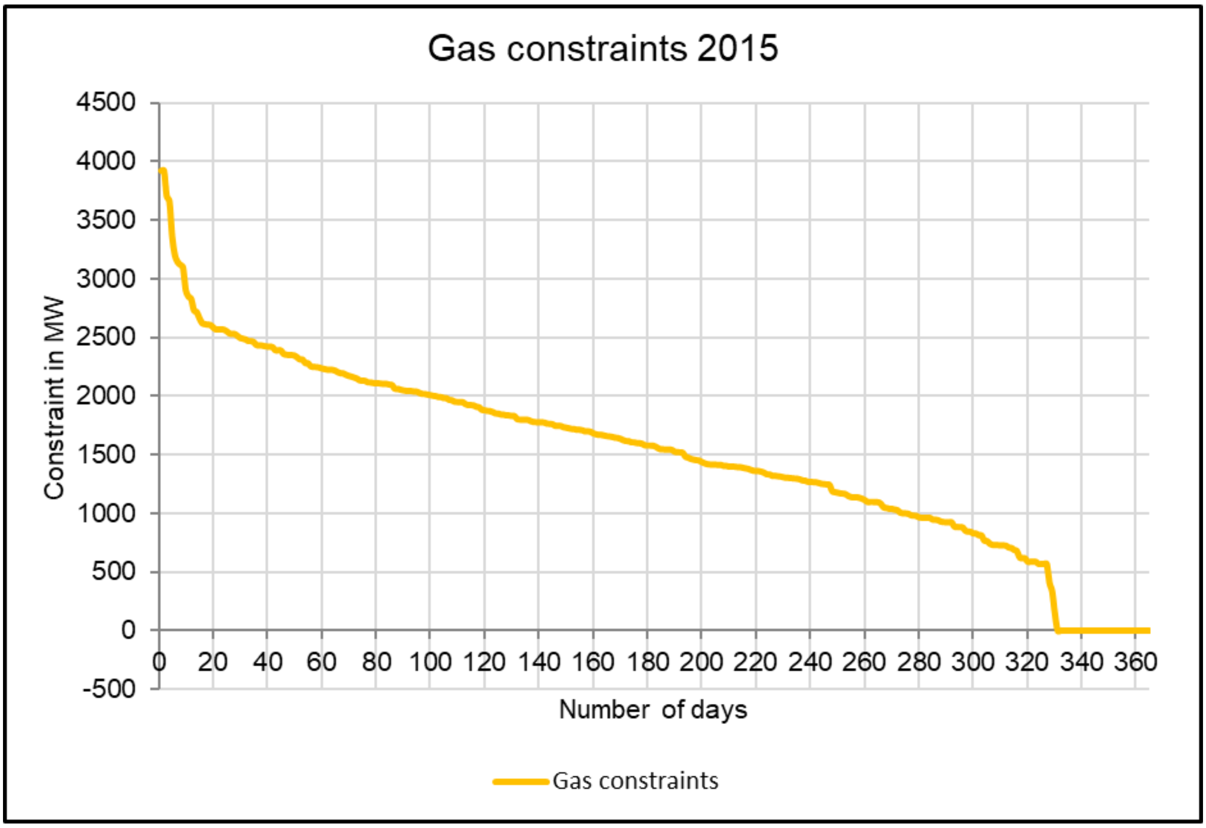
Annex 1 – Duration Curves of ANGC

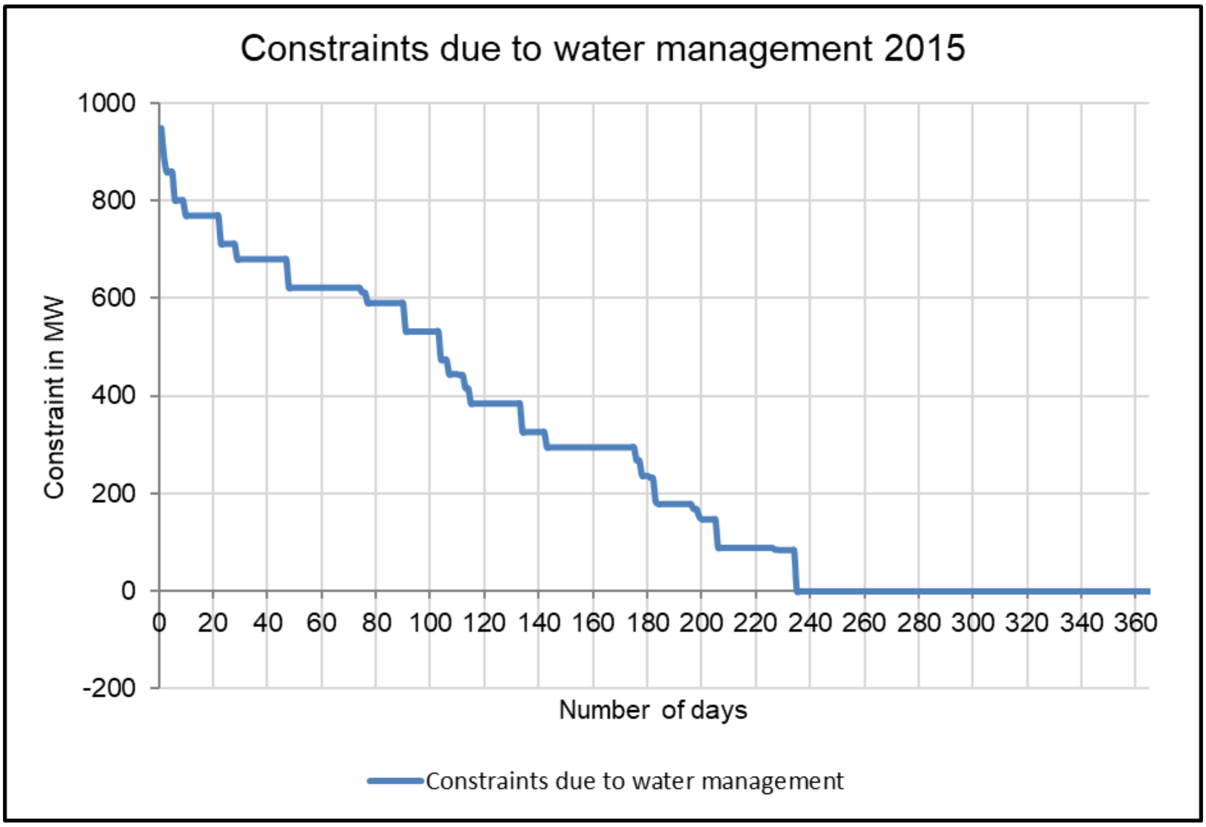


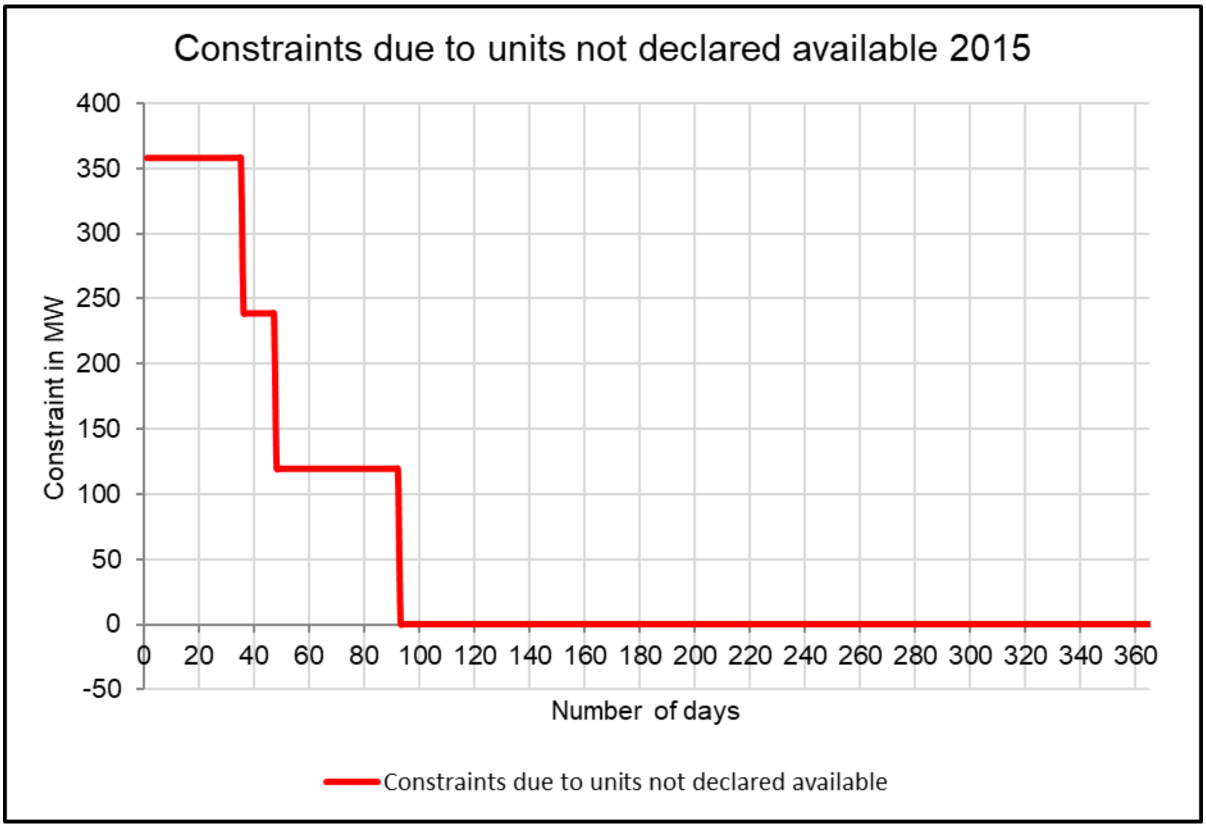
Annex 2 – Unutilised Generation Capacity

6.1. Generation Constraints

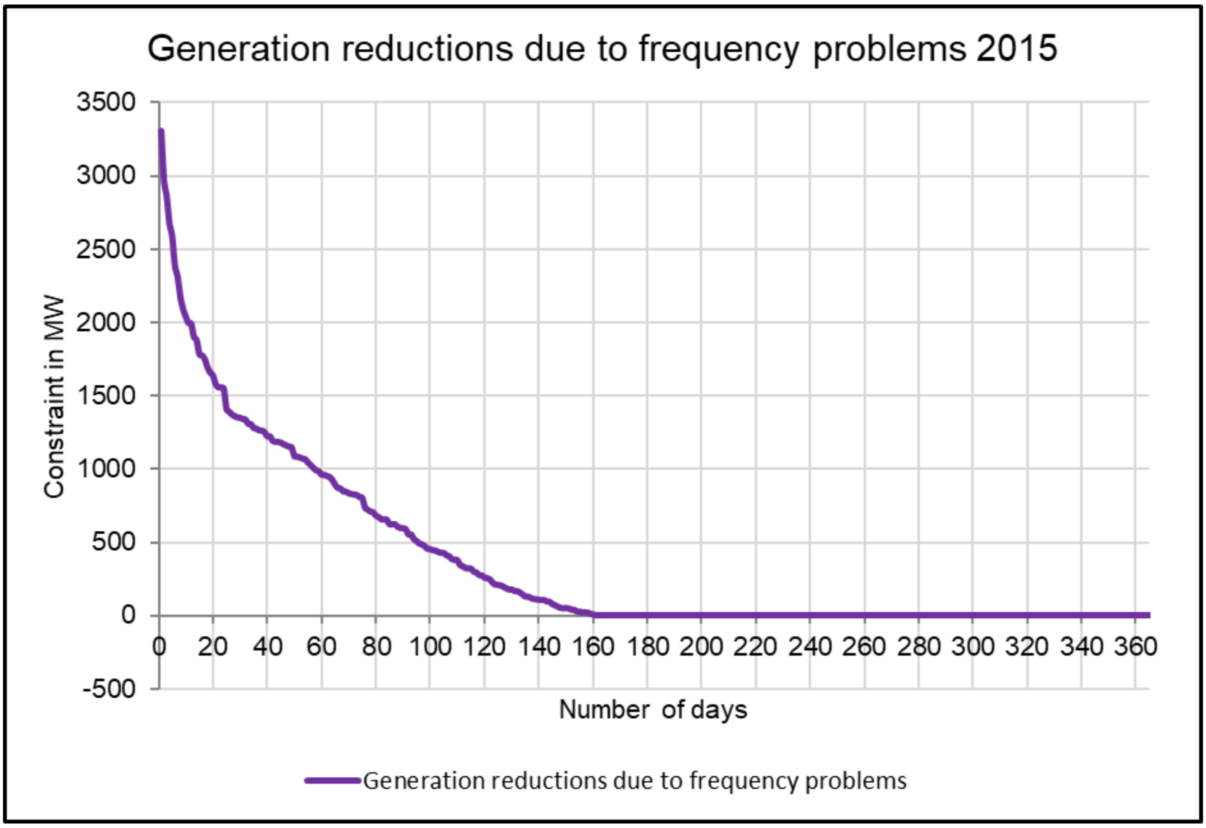




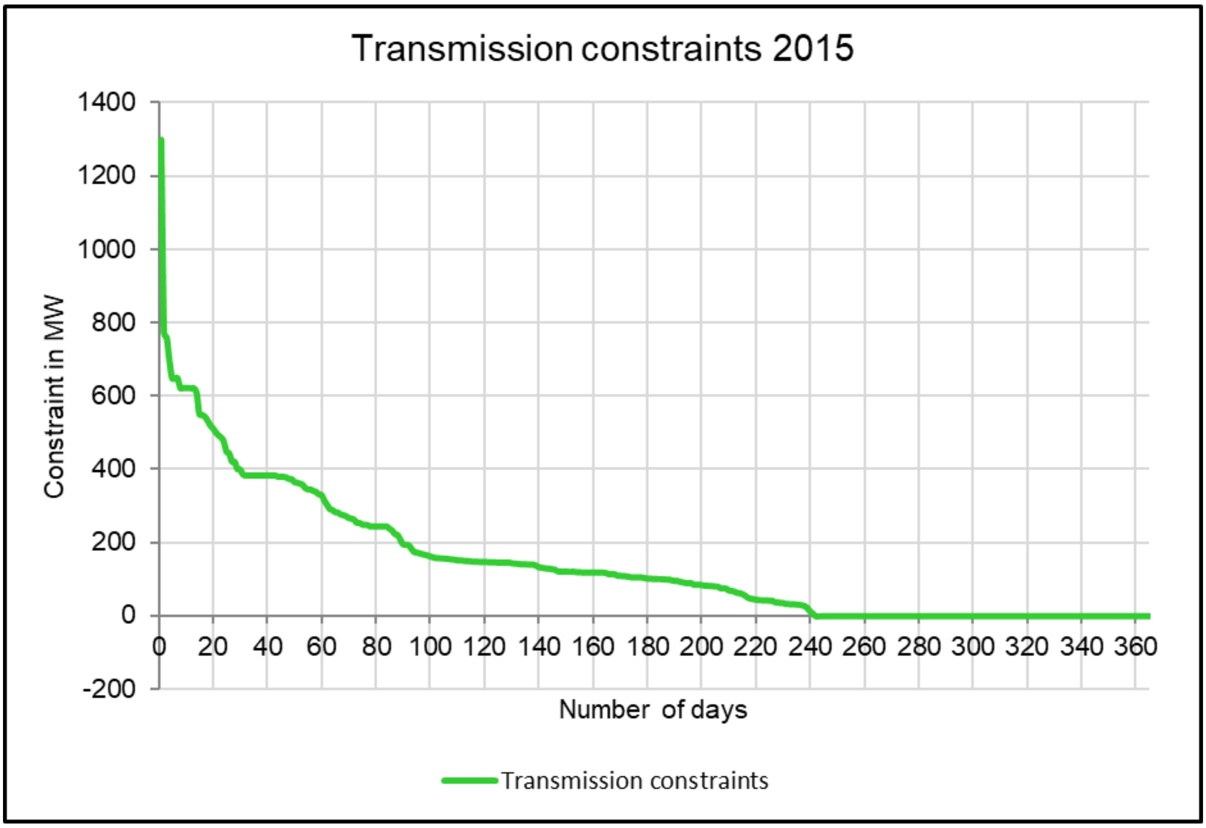

Constraints due to water management 2015
Constraint in MW
1000
800
600
400
200
0
-200
0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300 320 340 360
Number of days
Constraints due to water management


Constraints due to units not declared available 2015
Constraint in MW
400
350
300
250
200
150
100
50
0
-50
0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300 320 340 360
Number of days
Constraints due to units not declared available

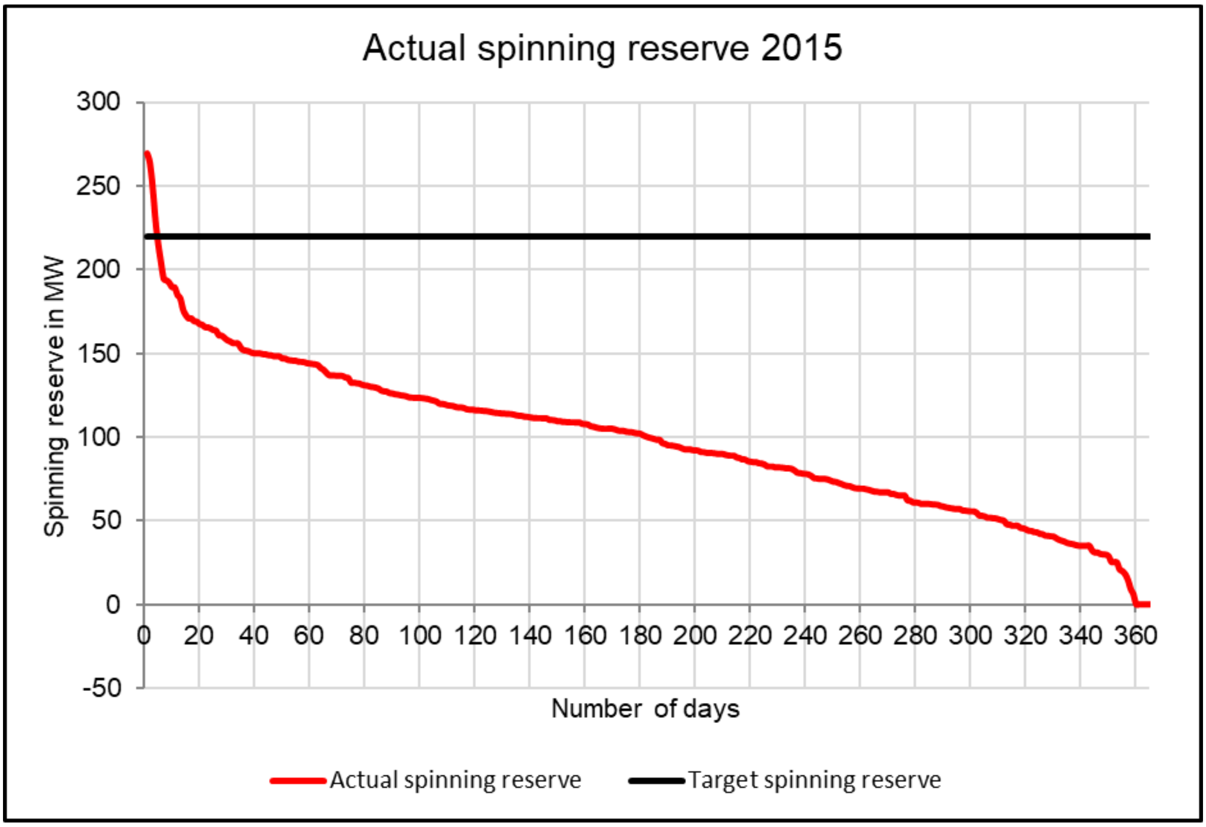
6.2. Generation Reductions Due to High Frequencies



6.3. Transmission Constraints



Annex 3 – Operating Reserves



Annex 4 – Additional Information for Each Power Station

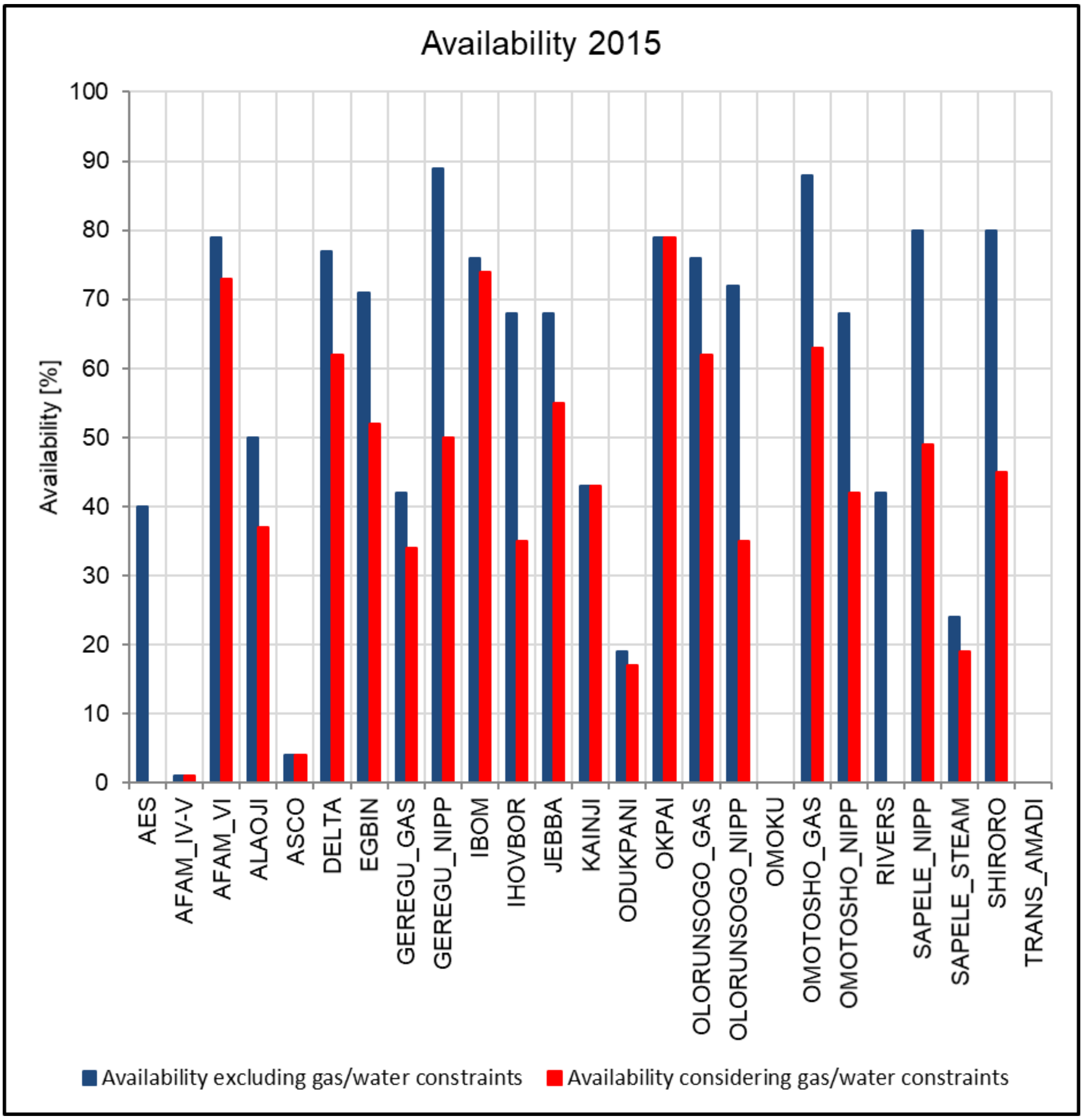
6.4. Average Constraints for Each Power Station

Power station	Gas constraints [MW]	Water management constraints [MW]	Constraints due to units not declared available [MW]	Total Constraints
AES GAS	113	0	0	113
AFAM IV-V (GAS)	0	0	0	0
AFAM VI GAS/STEAM	37	0	0	37
ALAOJI NIPP GAS	63	0	0	63
ASCO	0	0	0	0
DELTA (GAS)	88	0	0	88
EGBIN STEAM	231	0	0	231
GEREGU GAS	32	0	0	32
GEREGU NIPP	167	0	0	167
IBOM	2	0	0	2
IHOVBOR NIPP	149	0	0	149
JEBBA HYDRO	0	73	0	73
KAINJI HYDRO	0	0	16	16
ODUKPANI NIPP	13	0	41	54
OKPAI GAS/STEAM	1	0	0	1
OLORUNSOGO GAS	48	0	0	48
OLORUNSOGO NIPP GAS	212	0	0	212
OMOKU	0	0	0	0
OMOTOSHO GAS	74	0	0	74
OMOTOSHO NIPP GAS	122	0	0	122
RIVERS IPP	66	0	0	66
SAPELE (STEAM)	20	0	0	20
SAPELE NIPP	74	0	0	74
SHIRORO HYDRO	0	204	0	204
TRANS-AMADI	0	0	0	0
Total constraints	1512	277	57	1846

6.5. Availability of Each Power Station

Table 21: Power station availability

Power station	Average values		
	ANGC [MW]	Availability excl. gas/water constraints [% NGC]	Availability incl. gas/water constraints [% NGC]
AES GAS	113	40	0
AFAM IV-V (GAS)	2	1	1
AFAM VI GAS/STEAM	500	79	73
ALAOJI NIPP GAS	239	50	37
ASCO	2	4	4
DELTA (GAS)	467	77	62
EGBIN STEAM	870	71	52
GEREGU GAS	173	42	34
GEREGU NIPP	382	89	50
IBOM	87	76	74
IHOVBOR NIPP	304	68	35
JEBBA HYDRO	386	68	55
KAINJI HYDRO	214	43	43
ODUKPANI NIPP	115	20	17
OKPAI GAS/STEAM	371	79	79
OLORUNSOGO GAS	254	76	62
OLORUNSOGO NIPP GAS	418	72	35
OMOKU	0	0	0
OMOTOSHO GAS	269	88	63
OMOTOSHO NIPP GAS	324	68	42
RIVERS IPP	65	42	0
SAPELE (STEAM)	104	24	19
SAPELE NIPP	190	80	49
SHIRORO HYDRO	472	80	45
TRANS-AMADI	0	0	0


Availability 2015
Availability [%]
100
90
80
70
60
50
40
30
20
10
0
AES
AFAM_IV-V
AFAM_VI
ALAOJI
ASCO
DELTA
EGBIN
GEREGU_GAS
GEREGU_NIPP
IBOM
IHOVBOR
JEBBA
KAINJI
ODUKPANI
OKPAI
OLORUNSOGO_GAS
OLORUNSOGO_NIPP
OMOKU
OMOTOSHO_GAS
OMOTOSHO_NIPP
RIVERS
SAPELE_NIPP
SAPELE_STEAM
SHIRORO
TRANS_AMADI
Availability excluding gas/water constraints
Availability considering gas/water constraints

This report was prepared by the Market Operator with support from the Nigerian Energy Support Programme (NESP).