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Experimental and Simulation Analysis of the Nigerian 330 kV Grid with the New Haven–Nkalagu Sub-Transmission Line Integration

Eneh, Victor Ifeanyi[1], Eneh, Innocent Ifeanyichukwu[1], Ani, Okwuchukwu Innocent[2]

[1]Department of Electrical and Electronic Engineering, Enugu State University of Science and Technology, Agbani, Enugu.
[2]Department of Mechanical and Production Engineering, Enugu State University of Science and Technology, Agbani, Enugu
*Corresponding Author's E-mail: okwyenoch@yahoo.com

Abstract
This study centered on experimental and simulation analysis of the Nigerian 330 kV grid with the integration of the New Haven–Nkalagu 132 kV transmission line, focusing on load flow performance and protection coordination. A load flow analysis was conducted on the network, incorporating the New Haven–Nkalagu 132kV line via a 330/132kV transformer to assess system behavior during faults. PSAT software in MATLAB was used for modeling, analyzing bus, line, and generator data, ensuring accurate voltage and power flow adjustments for system stability. The substations include New Haven 330 kV, New Haven 132 kV, and Nkalagu 132 kV with transmission voltage levels of 328 kV, 131kV, and 128 kV respectively. These buses had fault current levels of 4000 A, 3000 A, and 2500 A respectively as calculated in the analytical sessions. The test carried out using a portion of the experimental data obtained from the National Control Centre Oshogbo showed an average absolute deviation of 0.9838% between the experimental data and the simulation results further validating the accuracy of the simulation model. Relay coordination analysis for varying fault currents indicated that Nkalagu relay acts as the primary protection, with tripping times significantly reduced as fault current increased. The current tap settings (CTS) for both relays also increased with rising fault levels, reaching maximum values of 8.69 A and 13.33 A for Nkalagu and New Haven, respectively. These results underscore the importance of precise relay configurations for optimal protection. Recommendations for further optimization through adaptive techniques were made to enhance grid performance under varying fault conditions. This research offers practical solutions for improved fault management and relay coordination in future grid expansions.

Keywords: load flow, relay coordination, fault current, Nigerian grid, New Haven–Nkalagu line, simulation analysis, power transmission.

1. Introduction

The integration of new transmission lines into national grids has prompted research on load flow and relay coordination, focusing on enhancing the reliability and efficiency of power systems. Load flow analysis is critical in determining the voltage, current, power, and losses in different parts of the grid during normal operation, whereas relay coordination ensures the protection and reliability of the grid in case of faults (Afolabi et al 2015). The integration of additional lines and renewable energy sources presents challenges in managing system stability and fault detection. The New Haven-Nkalagu 132 kV lines are part of Nigeria's transmission network, connecting the New Haven substation in Enugu to Nkalagu. These lines serve to transport high-voltage electricity over long distances, ensuring reliable power system and supporting industrial activities in southeastern Nigeria.

Load flow analysis plays a significant role in evaluating the steady-state performance of power systems. According to findings by Rehman et al (2024), the integration of new lines impacts the voltage profile and power losses across the grid, necessitating precise control of load flows to maintain system stability. In this context, power flow algorithms such as Gauss-Seidel, Newton-Raphson, and Fast-Decoupled methods have been utilized in simulation studies to model power distribution under varying loads. Simulation tools like MATPOWER and PowerWorld Simulator have been instrumental in load flow analysis of grid systems with multiple integrations (Sigurðsson& Abdel-Fattah, 2021). These studies highlight the impact of integrating distributed generation sources on the overall load flow, where intermittent sources like solar and wind power introduce uncertainties in power flow.

In experimental studies, researchers have utilized test systems to validate load flow solutions. According to Kini et al (2022), laboratory-scale models of the national grid were created to simulate load flow in a controlled environment. These models provided understanding into voltage stability and the redistribution of power when integrating additional transmission lines. Results from both experimental and simulation studies show that an optimized load flow can reduce power losses and improve voltage regulation, but challenges arise in dynamically managing load shifts during line integration (Yang et al 2019). Relay coordination ensures the protection of power systems by isolating faults while minimizing disruptions. Relay coordination becomes complex with line integration due to variations in fault currents and the need for precise relay settings. Experimental research by Akdag and Yeroglu (2021) showed that adaptive relays and Directional Overcurrent Relays (DOCR) are effective in mitigating relay coordination issues, particularly when integrating lines into existing grids. These relays adjust their settings dynamically based on the changing grid parameters.

Simulation studies by Al-Talaq and Al-Muhaini (2024) demonstrated the use of software like PSCAD and ETAP in relay coordination optimization, highlighting that relays need to adapt to the dynamic behavior of modern grids. The integration of renewable energy and distributed generation requires real-time adjustment of relay settings, as these sources can introduce erratic fault currents. Furthermore, simulation tools allow for comprehensive analysis of fault scenarios, which aids in the determination of optimal relay settings for both primary and backup protection schemes (Usama et al 2021). The integration of load flow and relay coordination studies is crucial for a resilient national grid. Both experimental and simulation approaches are necessary to identify optimal load flows and ensure effective fault detection and isolation during line integration. The authors identified a critical research gap in integrating the New Haven–Nkalagu 132 kV transmission line into Nigeria's 330 kV grid, particularly in load flow performance, fault management, and relay coordination. Existing systems lack effective fault detection and adaptive protection strategies under varying conditions. The study introduces a simulation model using PSAT in MATLAB to evaluate system behavior, optimize load flow, and improve relay coordination. Simulation results validated with experimental data propose precise relay settings and adaptive techniques, enhancing fault management and ensuring grid reliability for future expansions.

2.0 Materials and Methods

The study utilized data from the National Control Centre Oshogbo, incorporating bus, line, and generator parameters. Using PSAT software in MATLAB, the authors performed load flow analysis and relay coordination modeling. Analytical and experimental methods validated fault currents, relay settings, and tripping times, ensuring grid stability and protection optimization. The single line diagram of the Nigeria 330kV 48 bus networks consist of sixteen (16) generating stations comprising of three (3) hydro and thirteen (13) thermal, Thirty-two (32) PQ load stations and seventy-nine (79) transmission lines with a total installed capacity of 6500MW. The Nigeria 330-kV grid network can be grouped into three (3) sections: North, South-east and South-west sections. The Northern and South-west are connected through one double circuit line between Jebba TS and Oshogbo. The South-East is connected to the South-West through a single line from Osogbo to Benin and then one double circuit line from Ikeja West to Benin. The load flow was performed on the 330kv network with the New Haven – Nkalagu 132kV line incorporated with the aid of a 330/132KV transformer in order to incorporate the behavior of the generators and other power system components in the event of a fault at a distance from the source.

Moreover, the bus data, line data, generator data and load data of the Nigerian 330KV 48 bus power systems are in clear agreement with the diagram. The Model of the Nigerian 330KV 48 bus Power system was developed using the single line diagram. The generator buses were first modeled, followed by the load buses and the transmission lines. The New Haven – Nkalagu 132 KV transmission network was also incorporated into the model to enable the extraction of its load flow values. Modeling of the Nigerian 330KV 48-bus power system derived from the bus and transmission line data, comprising of 16 PV generators for load flow studies, 59 transmission lines and 32 load buses was achieved using PSAT software in MATLAB. The Generator buses were modeled using the PV bus block. The first step in the load flow analysis involved modeling of the Nigerian 330KV 48 bus power systems with its attached New Haven – Nkalagu 132KV power transmission network in PSAT. The second step of the load flow involved reading in of the bus data, line data, generator data etc for the power system.

The load flow analysis follows a systematic process. First, the bus admittance matrix for the power system was formed. Initial assumptions were made regarding the voltage magnitude and angle at each bus. Then, the real and reactive power flows were calculated. These values were updated, and the error in the power flows was checked. Next, the Jacobian matrix was formed to assist in solving for voltage corrections. Once the corrections were computed, the bus voltages were updated accordingly. Finally, the voltage limits of the converters were checked and adjusted as necessary to ensure system stability.

Previous study by the author (Eneh Eneh & Ajaelu, 2024) modeled the New Haven-Nkalagu 132KV transmission line in Simulink/Matlab, including its existing protection relay scheme, to assess fault conditions, such as phase-to-phase and phase-to-ground short circuits. Load currents were calculated for both buses, and current transformer ratios (C.T.R) were used to determine relay currents. Current Tap Settings (C.T.S) were selected to avoid unnecessary tripping under normal conditions. The Time Dial Settings (T.D.S) were adjusted to coordinate relay actions at Nkalagu and New Haven, with a 0.1-second delay for breaker operation. The operating time for each relay was calculated based on the relay's characteristics.

3.0 Results and Discussion

Table 1 present the voltage and power ratings for the New Haven–Nkalagu 132kV transmission line. The New Haven 132kV bus has a power rating of 119.2 MW and voltage of 131 KV, while Nkalagu's bus is rated at 117.6 MW and 128 KV. The 330KV New Haven bus carries 298 MW at 328 KV.

Table 1: Voltage and Power ratings of the New Haven Nkalagu 132KV Transmission Line

Parameter	New Haven 132KV Bus	Nkalagu 132KV Bus	New Haven 330KV Bus
Power	119.2 MW (149 MVA)	117.6 MW (147 MVA)	298 MW (372.5 MVA)
Voltage	131 KV	128 KV	328 KV
C.T ratio	500/4	400/4	1250/5
Fault current	3000	2500	4000

$$I_1 = \frac{L_1}{\sqrt{3} \times V} = \frac{147 \times 10^6}{\sqrt{3} \times 128 \times 10\text{^}3} = 663.05\ A$$

$I_2 = \frac{L_2}{\sqrt{3} \times V} = \frac{149 \times 10^6}{\sqrt{3} \times 131 \times 10\text{^}3} = 656.68\ A$

The currents flowing through the sections under normal operating condition is calculated as,

$I_{21} = I_1 = 663.05\ A$

$\mathrm{I_S} = \mathrm{I_{21}} + \mathrm{I_2} = 663.05 + 656.68 = 1319.73\ \mathrm{A}$

The relay currents are given by:

$i_{21} = \frac{I_{21}}{(C.T.R)_1} = \frac{663.05}{\frac{400}{4}} = \frac{663.05 \times 4}{400} = 6.6305\ A$

$i_S = \frac{I_S}{(C.T.R)_2} = \frac{663.05}{\frac{500}{4}} = \frac{663.05 \times 4}{500} = 10.5578\ A$

The C.T.S values for the relay at Nkalagu and that at New Haven becomes

$$(C.T.S)_1 = 7\ A$$
$$(C.T.S)_2 = 12\ A$$

These are the currents above which the relay trips in the event of a fault on the New Haven Nkalagu 132KV transmission line.

The Time Dial Settings (T.D.S) for coordinating the relays at New Haven and Nkalagu are calculated as:

$i_{SC1} = \frac{I_{SC1}}{(C.T.R)_1} = \frac{2500}{\frac{400}{4}} = \frac{2500 \times 4}{400} = 25\ A$

Expressing this value as a multiple of the pickup current or C.T.S value yields,

$$\frac{i_{SC1}}{(C.T.S)_1} = \frac{25}{7} = 3.571$$

Choosing the lowest time dial setting for relay 1 for fastest action,

$(T.D.S)_1 = \frac{1}{2}$

Pairing $(T.D.S)_1$ and R_1 and comparing it with the relay characteristic curve, the operating time of relay at Nkalagu is gotten as,

$$Operating\ time\ of\ Nkalagu\ relay = T_1 = 0.08\ s$$

The operating time of the relay at New Haven according to equation 3.13 becomes,

$T_2 = T_1 + 0.1 + 0.3$ = 0.08 + 0.1 + 0.3 = 0.48 s

The short circuit for a fault at Nkalagu as a multiple of the C.T.S at New Haven is,

$\frac{i_{SC1}}{(C.T.S)_2} = \frac{25}{12} = 2.083$

Then from the characteristics for 0.48 seconds operating time and 2.083 ratio, then,

$(T.D.S)_2 = 1$

The tripping time for both relays at Nkalagu and New Haven is calculated as:

$$t_{s1} = \frac{(T.D.S)_1}{7}\left(\left(\frac{A}{\left(i_{SC1}/_{(C.T.S)_1}\right)^P} - 1\right) + B\right) = \frac{0.5}{7}\left(\left(\frac{28.2}{\left(25/_7\right)^2} - 1\right) + 0.1217\right) = 0.09518\ seconds$$

$$t_{s2} = \frac{(T.D.S)_2}{7}\left(\left(\frac{A}{\left(i_{SC1}/_{(C.T.S)_2}\right)^P} - 1\right) + B\right) = \frac{1}{7}\left(\left(\frac{28.2}{\left(25/_{12}\right)^2} - 1\right) + 0.1217\right) = 0.8027\ seconds$$

To get a characteristic curve of the relay tripping time against its fault current, a run from 0 A to 3000 A in steps of 100 A will be made. i.e, the fault current at Nkalagu will be 0 A, 100 A, 200 A, 300 A, 400 A, 500 A, 600 A, 700 A, 800 A, 900 A, 1000 A, 1100 A, 1200 A, 1300 A, 1400 A, 1500 A, 1600 A, 1700 A, 1800 A, 1900 A, 2000 A, 2100 A, 2200 A, 2300 A, 2400 A, 2500 A, 2600 A, 2700 A, 2800 A, 2900 A, and 3000 A.

During this process, the time dial stings of the relay as well as the current tap settings of the relay will assume their calculated values. The constants A, B and P will also assume their values. Only the tripping times of the relay and their associated current tap settings will vary. The developed model of the New Haven – Nkalagu 132KV power transmission network with its existing protection relay scheme. The model was achieved in four stages. The first stage involved the modeling of the initial pick-up currents of both relays at Nkalagu and New Haven. The second stage involved the modeling of the tripping times of both relays at Nkalagu and New Haven. The third stage involved the modeling of the current tap settings (C.T.S) values of both relays at Nkalagu and New Haven for varying fault currents, while the fourth and final stage involved modeling the results viewer where all desired simulation results were viewed.

The impact of a fault on the Nkalagu bus on the New Haven–Nkalagu 132kV power transmission network was revealed by the load flow results, through which it was observed that the voltage of New Haven 330KV, New Haven 132KV, and Nkalagu 132 KV are 328kV, 131kV, and 128kV respectively. Likewise, their load flow powers are 298MW, 119.2MW and 117.6MW in equal order. Worthy to note again from the results are their fault current levels which are 4000A for New Haven 330KV bus, 3000A for New Haven 132KV bus and 2500A for Nkalagu 132KV bus. All these simulated results were further used in the analysis of the New Haven – Nkalagu 132KV transmission network protection. In an attempt to validate the developed simulation models, a comparison of the simulated load flow results was made with the experimental results as shown in table 2.

Table 2: Experimental values vs simulated values of Bus Voltages

Bus Name	Experimental value	Simulated Value	% Deviation
New Haven 330KV Bus	326	328	0.6135
New Haven 132KV	129	131	1.5504
Nkalagu 132KV	127	128	0.7874
			0.9838

The experimental values are the load flow results as obtained from NCC Oshogbo which was used as a secondary experimental data for this work. As can be seen from Table 2, the average percentage deviation of the simulated values from the experimental values is 0.9838%. This is acceptable in practice since the deviation is not more than five percent. The simulated tripping times and CTS values of both Nkalagu and New Haven relay for varying fault current showed that when the fault current is zero, the tripping times of both Nkalagu and New Haven relays are infinity whereas the current tap settings of both relays are respectively zero. At a fault current of 100 A, the tripping time of Nkalagu relay is 68.6 seconds, the tripping time of New Haven relay is 403.3 seconds, the C.T.S of Nkalagu relay is 0.2882 A and the C.T.S of New Haven relay is 0.4442 A. At maximum fault current of 3000, the tripping times of Nkalagu and New Haven relays are respectively 0.0399 seconds and 0.3755 seconds whereas their C.T.S values are 8.647 A and 13.33 A.

Supplementary data in tables 1-4 and Figures 1 to 4 gives a detailed representation of the tripping times of both New Haven and Nkalagu relay for the varying fault currents. As can be observed from the tables, the tripping time of Nkalagu and New Haven relay at fault current of 3000A is 0.0399 and 0.3755 seconds respectively. Similarly, the CTS value of Nkalagu and New Haven Relay are respectively 8.6466 A and 13.3254 A. These values need to be optimized so as to minimize the tripping times and maximize the CTS values of the relay for enhanced protection of the transmission network.

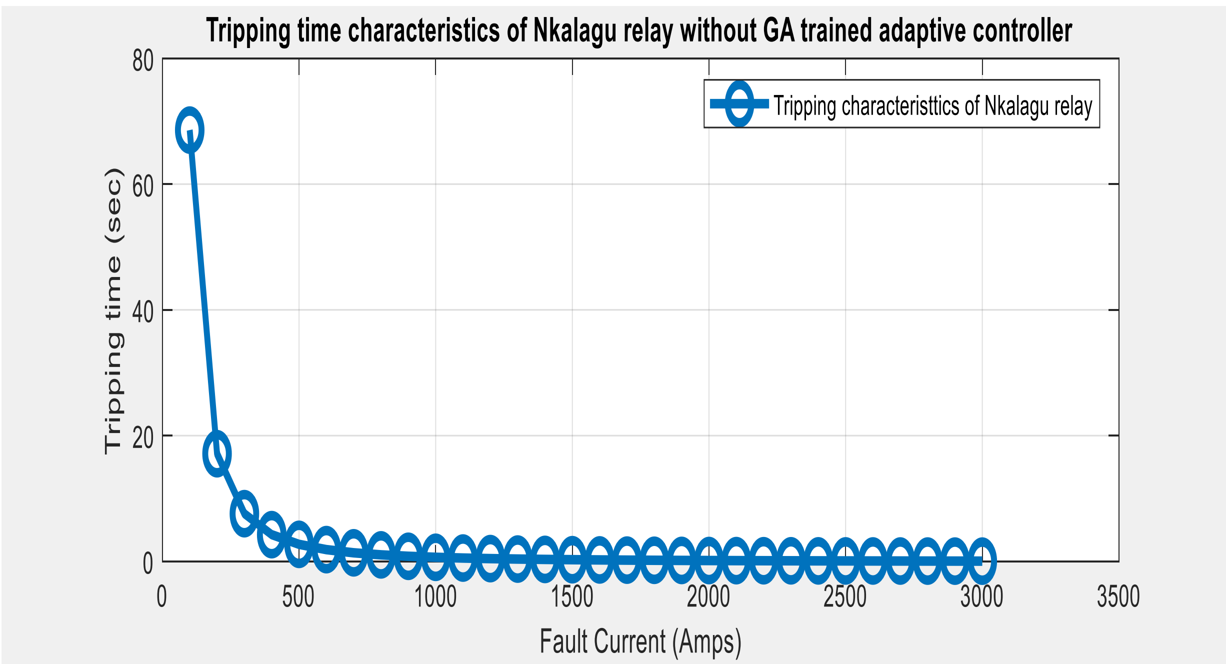

Figure 1: Tripping time characteristics of Nkalagu relay without GA trained adaptive controller

The tripping times curve of Nkalagu relays (Figure 1) shows that the tripping time of the relay reduces as the fault current increases. From the curve, it is clear that at a fault current of 500A and above, the tripping time of the relay is between 0.04s and 2.71s. In the same manner, at a fault current of less than 500A the duration of tripping is between 4.24 and 68.6s.

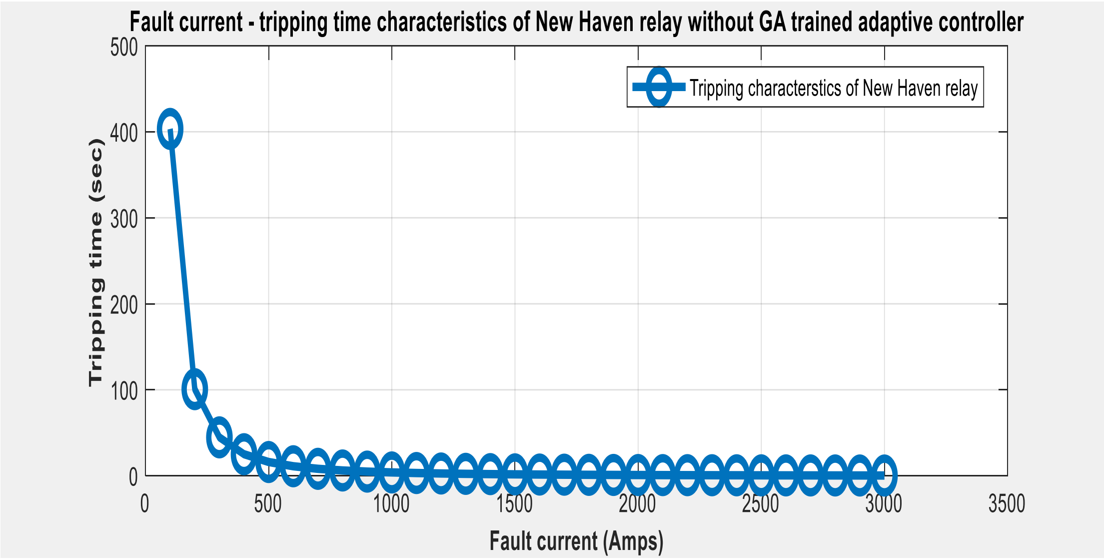

Figure 2: Tripping time characteristics of New Haven relay without GA trained adaptive controller

For the New Haven relay in figure 2, the tripping times are very low at a fault current of 500A and above ranging from 0.38s to 16.06s. Similarly, when the fault current is less than 500A, the tripping times is in the range of 25.14s to 403.33s. This shows that the relay acts as a standby/backup to the Nkalagu relay since if a fault occurs at Nkalagu, its relays will first trip but should incase it does not trip, the New Haven relay will trip in its stead.

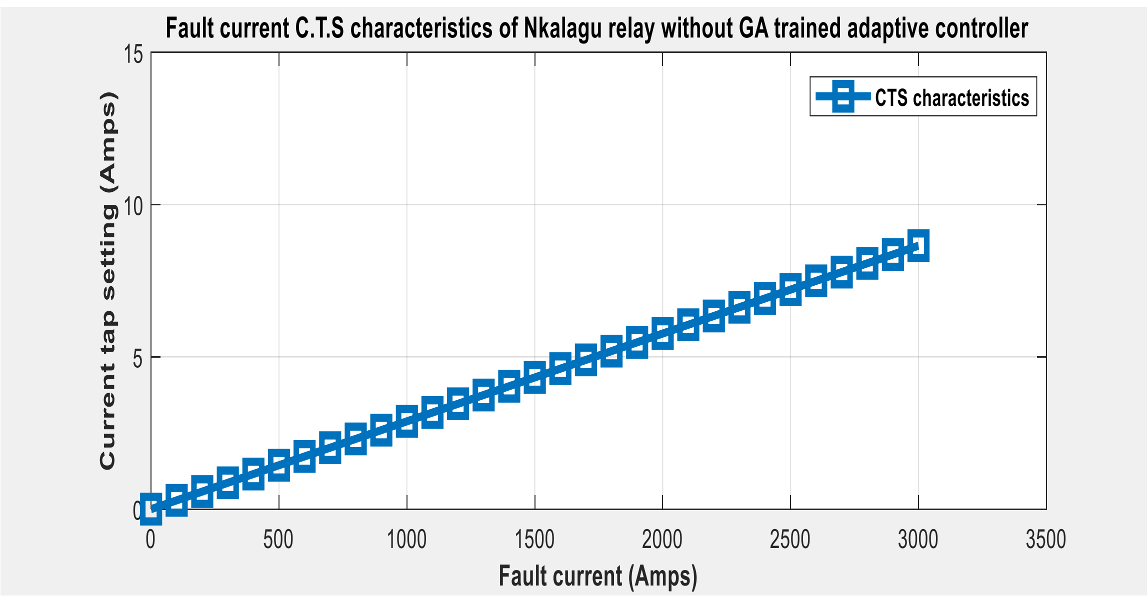

Figure 3: Fault current C.T.S characteristics of Nkalagu relay without GA trained adaptive controller

In figure 3, the fault current – C.T.S characteristics of Nkalagu relay without the genetic trained adaptive controller was plotted with the fault current (Amps) lying in the x-axis whereas the current tap settings (Amps) lie on the y-axis. The curve shows that unlike the tripping time curve, the C.T.S of the relay increases as its fault current increases. The C.T.S of the relay progressed steadily from 0.29A to 8.69A as its fault current increases. So, at a maximum fault current of 3000A, the current tap setting of the relay is set as 8.69A.

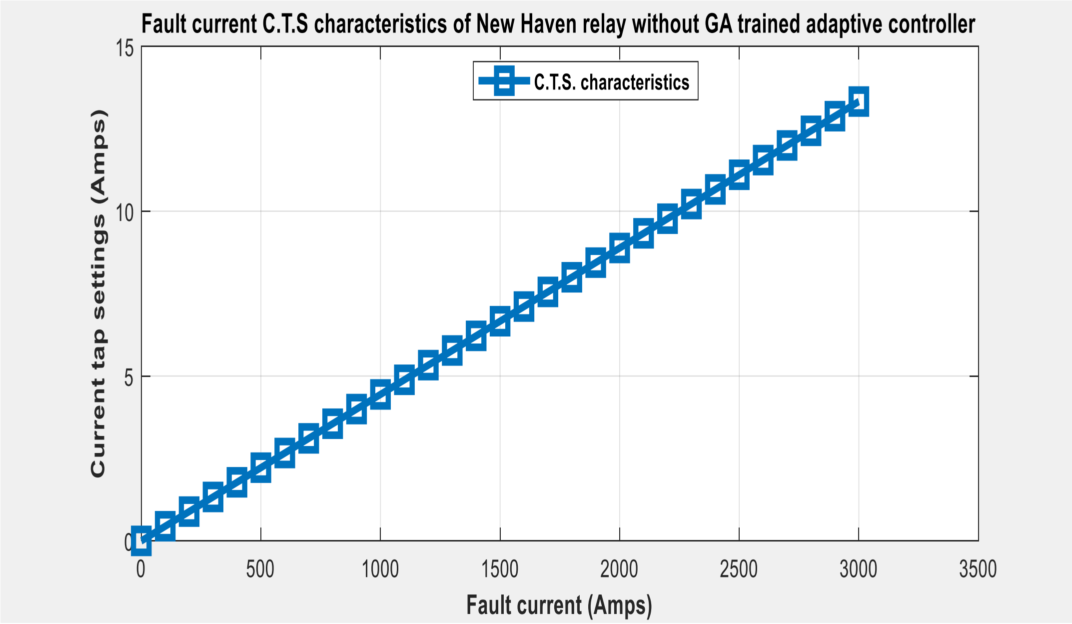

Figure 4: Fault current C.T.S characteristics of New Haven relay without GA trained adaptive controller

For the New Haven relay, the fault current - C.T.S characteristics of New Haven relay without GA trained adaptive controller as shown in figure 4 shows that the current tap settings of the relay increase as its fault current increases. The C.T.S. as observed in the figure progressively increased from 0.44A to 13.325A. Thus, at a maximum fault current of 3000A, the C.T.S of the relay is set at 13.23A.

The analysis of the New Haven-Nkalagu 132 kV power transmission network, encompassing load flow, fault conditions, and relay coordination, offers critical understanding into the system's operational performance. In the New Haven-Nkalagu 132 kV line, the simulated load flow voltages were 328 kV, 131 kV, and 128 kV for New Haven 330 kV, New Haven 132 kV, and Nkalagu 132 kV buses, respectively. Correspondingly, the load flow power levels were 298 MW, 119.2 MW, and 117.6 MW, with fault currents of 4000 A, 3000 A, and 2500 A at these buses. The experimental values from NCC Oshogbo showed minimal deviations from the simulated results, with an average percentage deviation of 0.9838%, well within the acceptable range of five percent as per Schillaci and Schillaci (2022). This finding agrees with Martinenas et al (2016), who also reported similar low deviations in their load flow studies, reinforcing the reliability of simulation models when validated against experimental data. In contrast, Al-Talaq and Al-Muhaini (2024) observed higher deviations in a different transmission network, which they attributed to varying network configurations and modeling techniques. Similarly, Akdag, and Yeroglu (2021) reported less accurate load flow simulations in another study, highlighting the importance of precise modeling for different grid structures. This comparative analysis underscores the necessity of tailored simulation approaches to achieve high accuracy in diverse transmission systems.

The study evaluated the tripping times and current tap settings (CTS) of the Nkalagu and New Haven relays under varying fault currents. At a fault current of 3000 A, the tripping times were 0.0399 seconds for Nkalagu and 0.3755 seconds for New Haven, with CTS values of 8.6466 A and 13.3254 A, respectively. These results indicate that the Nkalagu relay responds faster to faults, positioning it as the primary protective device for this section of the network. In a related study, Sahoo and Samantaray (2020) found that backup relays exhibited longer tripping times, similar to the New Haven relay's performance in this study. This finding agreed with Yang et al (2019), who demonstrated that without genetic algorithm (GA)-trained adaptive controllers, relay tripping times are suboptimal, particularly at lower fault currents. Alasali et al (2022) emphasized that integrating GA can reduce tripping time, enhancing protection schemes. This study's observation of significant delays at lower fault currents (e.g., 68.6 seconds for Nkalagu and 403.3 seconds for New Haven at 100 A) aligns with Adewale and Ilesanmi's conclusions, highlighting the potential for optimization through advanced control techniques.

The relationship between fault current and CTS for both relays showed a progressive increase in CTS values with rising fault currents. For Nkalagu, CTS values increased from 0.2882 A at 100 A fault current to 8.6466 A at 3000

A, while the New Haven relay's CTS values rose from 0.4442 A to 13.3254 A, over the same range. This trend is consistent with Kim and Wang (2016), who reported similar CTS behavior in another 132 kV transmission line, emphasizing the necessity for adaptive relay settings to handle varying fault conditions effectively. In contrast, Ashrafian et al (2014) observed less pronounced increases in CTS values at higher fault currents, attributing this to limitations in relay settings that were not adequately designed for higher fault levels. This discrepancy highlights the importance of precise relay configuration to ensure optimal performance across a range of fault conditions.

4.0. Conclusion

The study provided valuable understanding into the performance and reliability of the transmission network following the integration of the New Haven–Nkalagu 132 kV line. Both experimental and simulated load flow analyses demonstrated high consistency, with an average percentage deviation of 0.9838%, affirming the accuracy of the developed simulation models. The results showed minimal voltage and power losses across the buses, ensuring efficient power delivery along the line. The analysis of fault currents and relay coordination revealed that both Nkalagu and New Haven relays exhibited effective tripping times at higher fault currents, with Nkalagu serving as the primary relay and New Haven as a backup. The progressive increase in Current Tap Settings (CTS) values with rising fault currents underscored the need for accurate relay configuration to optimize protection across varying fault conditions.

The findings indicated that while the New Haven–Nkalagu integration enhances grid reliability, opportunities for further improvements exist. Specifically, optimizing relay settings using advanced techniques such as genetic algorithm (GA)-trained adaptive controllers could further reduce tripping times and enhance system protection. This would be particularly beneficial for handling lower fault current scenarios where delays in tripping times were observed. This study contributes to a better understanding of the operational dynamics of Nigeria's national grid and offers recommendations for enhancing protection systems in future grid expansions and integrations. Further research is encouraged to explore adaptive and AI-driven methods for optimizing grid protection mechanisms.

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Supplementary data

Supplementary data 1: Tripping time computation for Nkalagu Relay

Fault Current at Nkalagu (Amps)	C.T ratio at Nkalagu	(C.T.S) at Nkalagu (Amps)	Nkalagu Relay fault current (Amps)	A	B	P	(T.D.S) at Nkalagu	Tripping time of Nkalagu relay
0	100	7	0	19.61	0.491	2	0.5	0.0000
100	100	7	1	19.61	0.491	2	0.5	68.5986
200	100	7	2	19.61	0.491	2	0.5	17.1224
300	100	7	3	19.61	0.491	2	0.5	7.5898
400	100	7	4	19.61	0.491	2	0.5	4.2533
500	100	7	5	19.61	0.491	2	0.5	2.7090
600	100	7	6	19.61	0.491	2	0.5	1.8702
700	100	7	7	19.61	0.491	2	0.5	1.3644
800	100	7	8	19.61	0.491	2	0.5	1.0361
900	100	7	9	19.61	0.491	2	0.5	0.8110
1000	100	7	10	19.61	0.491	2	0.5	0.6500
1100	100	7	11	19.61	0.491	2	0.5	0.5309
1200	100	7	12	19.61	0.491	2	0.5	0.4403
1300	100	7	13	19.61	0.491	2	0.5	0.3698
1400	100	7	14	19.61	0.491	2	0.5	0.3138
1500	100	7	15	19.61	0.491	2	0.5	0.2687
1600	100	7	16	19.61	0.491	2	0.5	0.2317
1700	100	7	17	19.61	0.491	2	0.5	0.2011
1800	100	7	18	19.61	0.491	2	0.5	0.1755
1900	100	7	19	19.61	0.491	2	0.5	0.1538
2000	100	7	20	19.61	0.491	2	0.5	0.1352
2100	100	7	21	19.61	0.491	2	0.5	0.1193
2200	100	7	22	19.61	0.491	2	0.5	0.1055
2300	100	7	23	19.61	0.491	2	0.5	0.0934
2400	100	7	24	19.61	0.491	2	0.5	0.0828
2500	100	7	25	19.61	0.491	2	0.5	0.0735
2600	100	7	26	19.61	0.491	2	0.5	0.0652
2700	100	7	27	19.61	0.491	2	0.5	0.0578
2800	100	7	28	19.61	0.491	2	0.5	0.0512
2900	100	7	29	19.61	0.491	2	0.5	0.0453
3000	100	7	30	19.61	0.491	2	0.5	0.0399

Supplementary data 2. Tripping time computation for New Haven Relay

Fault Current at Nkalagu (Amps)	C.T ratio at Nkalagu	(C.T.S) at New Haven (Amps)	Nkalagu Relay fault current (Amps)	A	B	P	(T.D.S) at New Haven	Tripping time of New Haven relay
0	100	12	0	19.61	0.491	2	1	0.0000
100	100	12	1	19.61	0.491	2	1	403.3330
200	100	12	2	19.61	0.491	2	1	100.7787
300	100	12	3	19.61	0.491	2	1	44.7501
400	100	12	4	19.61	0.491	2	1	25.1401
500	100	12	5	19.61	0.491	2	1	16.0635
600	100	12	6	19.61	0.491	2	1	11.1330
700	100	12	7	19.61	0.491	2	1	8.1601
800	100	12	8	19.61	0.491	2	1	6.2305
900	100	12	9	19.61	0.491	2	1	4.9076
1000	100	12	10	19.61	0.491	2	1	3.9613
1100	100	12	11	19.61	0.491	2	1	3.2612
1200	100	12	12	19.61	0.491	2	1	2.7287
1300	100	12	13	19.61	0.491	2	1	2.3143
1400	100	12	14	19.61	0.491	2	1	1.9855
1500	100	12	15	19.61	0.491	2	1	1.7202
1600	100	12	16	19.61	0.491	2	1	1.5031
1700	100	12	17	19.61	0.491	2	1	1.3232
1800	100	12	18	19.61	0.491	2	1	1.1724
1900	100	12	19	19.61	0.491	2	1	1.0448
2000	100	12	20	19.61	0.491	2	1	0.9358
2100	100	12	21	19.61	0.491	2	1	0.8420
2200	100	12	22	19.61	0.491	2	1	0.7608
2300	100	12	23	19.61	0.491	2	1	0.6899
2400	100	12	24	19.61	0.491	2	1	0.6276
2500	100	12	25	19.61	0.491	2	1	0.5727
2600	100	12	26	19.61	0.491	2	1	0.5240
2700	100	12	27	19.61	0.491	2	1	0.4807
2800	100	12	28	19.61	0.491	2	1	0.4418
2900	100	12	29	19.61	0.491	2	1	0.4070
3000	100	12	30	19.61	0.491	2	1	0.3755

Supplementary data 3. C.T.S computation for Nkalagu Relay

Fault Current at Nkalagu (Amps)	C.T ratio at Nkalagu	Nkalagu Relay fault current (Amps)	(T.D.S) at Nkalagu	A	B	P	tripping time of Nkalagu relay	C.T.S at Nkalagu
0	100	0	0.5	19.61	0.491	2	0.08	0
100	100	1	0.5	19.61	0.491	2	0.08	0.2882
200	100	2	0.5	19.61	0.491	2	0.08	0.5764
300	100	3	0.5	19.61	0.491	2	0.08	0.8647
400	100	4	0.5	19.61	0.491	2	0.08	1.1529
500	100	5	0.5	19.61	0.491	2	0.08	1.4411
600	100	6	0.5	19.61	0.491	2	0.08	1.7293
700	100	7	0.5	19.61	0.491	2	0.08	2.0175
800	100	8	0.5	19.61	0.491	2	0.08	2.3057
900	100	9	0.5	19.61	0.491	2	0.08	2.5940
1000	100	10	0.5	19.61	0.491	2	0.08	2.8822
1100	100	11	0.5	19.61	0.491	2	0.08	3.1704
1200	100	12	0.5	19.61	0.491	2	0.08	3.4586
1300	100	13	0.5	19.61	0.491	2	0.08	3.7468
1400	100	14	0.5	19.61	0.491	2	0.08	4.0351
1500	100	15	0.5	19.61	0.491	2	0.08	4.3233
1600	100	16	0.5	19.61	0.491	2	0.08	4.6115
1700	100	17	0.5	19.61	0.491	2	0.08	4.8997
1800	100	18	0.5	19.61	0.491	2	0.08	5.1879
1900	100	19	0.5	19.61	0.491	2	0.08	5.4762
2000	100	20	0.5	19.61	0.491	2	0.08	5.7644
2100	100	21	0.5	19.61	0.491	2	0.08	6.0526
2200	100	22	0.5	19.61	0.491	2	0.08	6.3408
2300	100	23	0.5	19.61	0.491	2	0.08	6.6290
2400	100	24	0.5	19.61	0.491	2	0.08	6.9172
2500	100	25	0.5	19.61	0.491	2	0.08	7.2055
2600	100	26	0.5	19.61	0.491	2	0.08	7.4937
2700	100	27	0.5	19.61	0.491	2	0.08	7.7819
2800	100	28	0.5	19.61	0.491	2	0.08	8.0701
2900	100	29	0.5	19.61	0.491	2	0.08	8.3583
3000	100	30	0.5	19.61	0.491	2	0.08	8.6466

Supplementary data 4. C.T.S computation for New Haven Relay

Fault Current at Nkalagu (Amps)	**C.T ratio at Nkalagu**	**Nkalagu Relay fault current (Amps)**	**(T.D.S) at New Haven**	**A**	**B**	**P**	**tripping time of New Haven relay**	**C.T.S at New Haven**
0	100	0	1	19.61	0.491	2	0.48	0
100	100	1	1	19.61	0.491	2	0.48	0.4442
200	100	2	1	19.61	0.491	2	0.48	0.8884
300	100	3	1	19.61	0.491	2	0.48	1.3325
400	100	4	1	19.61	0.491	2	0.48	1.7767
500	100	5	1	19.61	0.491	2	0.48	2.2209
600	100	6	1	19.61	0.491	2	0.48	2.6651
700	100	7	1	19.61	0.491	2	0.48	3.1093
800	100	8	1	19.61	0.491	2	0.48	3.5535
900	100	9	1	19.61	0.491	2	0.48	3.9976
1000	100	10	1	19.61	0.491	2	0.48	4.4418
1100	100	11	1	19.61	0.491	2	0.48	4.8860
1200	100	12	1	19.61	0.491	2	0.48	5.3302
1300	100	13	1	19.61	0.491	2	0.48	5.7744
1400	100	14	1	19.61	0.491	2	0.48	6.2185
1500	100	15	1	19.61	0.491	2	0.48	6.6627
1600	100	16	1	19.61	0.491	2	0.48	7.1069
1700	100	17	1	19.61	0.491	2	0.48	7.5511
1800	100	18	1	19.61	0.491	2	0.48	7.9953
1900	100	19	1	19.61	0.491	2	0.48	8.4395
2000	100	20	1	19.61	0.491	2	0.48	8.8836
2100	100	21	1	19.61	0.491	2	0.48	9.3278
2200	100	22	1	19.61	0.491	2	0.48	9.7720
2300	100	23	1	19.61	0.491	2	0.48	10.2162
2400	100	24	1	19.61	0.491	2	0.48	10.6604
2500	100	25	1	19.61	0.491	2	0.48	11.1045
2600	100	26	1	19.61	0.491	2	0.48	11.5487
2700	100	27	1	19.61	0.491	2	0.48	11.9929
2800	100	28	1	19.61	0.491	2	0.48	12.4371
2900	100	29	1	19.61	0.491	2	0.48	12.8813
3000	100	30	1	19.61	0.491	2	0.48	13.3254