iJET EXPLORE International Journal of Engineering & Technology
CENTRE OF PROFESSIONAL RESEARCH PUBLICATIONS
ISSN 2049-3444

International Journal of Engineering and Technology Volume 3 No. 9, September, 2013

Using Substation Automation System for Faults Management and Analysis in Electric Power Distribution Systems in Nigeria

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ABSTRACT

The need to evolve an indigenous solution on fault management and analysis in Electric Power Distribution System (EPDS) informed this research work on using Substation Automation for real-time fault reporting through the integration of a mobile communication-based System. The system encompasses the development of software driven hardware positioned at the remotely located Sub-stations at the Low Voltage level to keep track of the state of the network in real-time and harvests data for further processing. The detection of faults exploits threshold passing algorithm. The field implementation was carried out in Akure electric power distribution system in Nigeria. The system provides opportunity for managing faults by creating faults database and assessing the performance index. The approach offers enhanced performance over the traditional approach and provides useful suggestion to improve delivery of power to consumers.

Keywords: *Current, Electric Power Distribution, Voltage, Faults and Substation Automation*

1. INTRODUCTION

A fault condition is a sudden abnormal alteration to the normal circuit arrangement [1] (Christophe 2006) that results in energy being dissipated in manner other than the serving of the intended load [2] (Mo et al 1993). The circuit quantities, current and voltage, will alter, and the circuit will pass through a transient state to a steady state. In the transient state, the initial magnitude of the fault current will depend upon the point on the voltage wave at which the fault occurs. The decay of the transient condition, until it merges into steady state, is a function of the parameters of the circuit elements [1](Christophe 2006). The different types of faults that occur in a network can be classified in three major groups [1,3] (Christophe 2006; Kezunovic 2001): short circuit faults; open circuited faults and simultaneous faults. Simultaneous faults are a combination of the two groups described above. The most dangerous phenomenon is normally the high current that occurs at a short circuit. The magnitude of the fault current is dependent on what type of fault that occurs [1]. The faults have different possible origin which includes electric, climatologic and human activity or error.

1.1 Short Circuit Faults

Short circuit is the accidental or intentional conductive connection through a relatively low resistance or impedance between two or more points of a circuit which are normally at different potentials [1,3] (Christophe 2006; Kezunovic 2006; IEE 1999). When short-circuit occurs in an installation fed by a distribution network (far from the generator), a short circuit current consisting of two components-the transient aperiodic component and steady state sinusoidal component will flow [4] (Das 1998). The aperiodic components decay towards zero. On three-phase power systems, there are ten distinct possible shunt faults types [5](Horowitz et al 1995) which involves three phase, two phase and singe phase. These are classified in the following four categories [4] (Das 1998).

1.2 Single-Phase-to-Ground Faults

b) Two-phase-to-ground faults.
c) Phase-to-phase faults.
d) Three-phase faults.

1.3 Single-Phase-to-Ground Faults

The following three types of single-phase-to-ground faults occurred in EPDS [1,4](Das 1998; Christophe 2006):

a) Phase A-to-ground faults.
b) Phase B-to-ground faults.
c) Phase C-to-ground faults.

1.4 Two-Phase-To-Ground Faults

The following three types of Two-phase-to-ground faults are defined.

a) Phase A and phase B-to-ground faults
b) Phase C and phase A-to-ground faults.
c) Phase B and phase C-to-ground faults.

1.5 Phase-to-Phase Faults

The three types of phase-to-phase faults that can be experienced on three phase lines are as follows.

a) Phase B-to-phase C faults.
b) Phase C-to-phase A faults.
c) Phase A-to-phase B faults

2. SYSTEM PERFORMANCE INDEX

The most common metrics used to evaluate utility reliability performance are CMI, SAIFI, SAIDI, and CAIDI [6]. CMI measures the number of minutes all of the customers are without service, SAIFI measures how often a customer expect to experience an outage, SAIDI measures average outage duration per customer, and CAIDI measures average can outage duration if an outage is experienced, or average restoration time. Each of these measures is defined as follows [6,7,8](Boknam et al 2007; Bollene 1999):

(a) Customer Interruptions (CI) is expressed as;

$$CI = \sum \geq Customer\ Outage\ Events\ (Duration\ 5\text{min}) \quad (1)$$

(b) Customer Minutes of Interruption (CMI): The total minutes of interruption for all outage events qualifying as Customer Interruptions.

$$CMI = \sum Outage\ Duration\ (\text{min}) \quad (2)$$

(c) System Average Interruption Frequency Index (SAIFI) is expressed by equation 3 while System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI) are expressed by equation 4 and 5 respectively.

$$SAIFI = {}^{CI}/_{Number\ of\ Customers\ Served} \quad (3)$$

$$SAIDI = {}^{CMI}/_{Number\ of\ Customers\ Served} \quad (4)$$

$$CAIDI = {}^{CMI}/_{CI} \quad (5)$$

MAIFI (Momentary Average Interruption Frequency Index) counts all service interruptions regardless of their duration.

2.1 Review of Distribution Automation System

The Institute of Electrical and Electronic Engineers (IEEE) has defined a Distribution Automation System (DAS) as a system that enables an electric utility to remotely monitor, coordinate and operate distribution components, in a real-time mode from remote locations (Bassett 1998) and [9,10](Gupta 2008; Gupta et al 2004). Functions that can be automated in distribution systems can be classified into two categories namely- monitoring functions and control functions [11](Brand et al 2003). These require two key software elements – the Master Distribution Automation (DA) Software and the Engineering Analysis Software. Distribution Automation can be broadly classified according to [12,13](Brown et al 1991) and Donald et al (1991) as:

- Substation Automation (SA);
- Feeder Automation; and
- Consumer Location Automation

2.2 Communication System for Real-Time Monitoring

Perhaps, the most difficult task in automating a distribution network is the selections of an appropriate communications technique for the implementation of remote control/reporting facilities [10] (Gupta 2008). Fig 2.13 describes the links between the Remote Terminal Unit (RTU) and Distribution Control Center (DCC). According to [14,15](James 2007; Jones 2005; Estra1da 2003 and Marihart 2001) several techniques are available. These are:

a) hard-wired
b) Public Switched Telephone Network (PSTN)
c) mobile radio (packet switched data)
d) conventional or low-powered radio (includingMicrowave)
e) Power Line Carrier Communication (PLCC)

2.3 Wireless communication: Global System for Mobile Communication (GSM)

In Nigeria, three GSM operators which commenced operation in 2001 with 1 million subscribers have since attained a subscriber base of over 50 million by 2009 [16](NCC, 2010). The detailed information of GSM growth in Nigeria is shown in Table 1. The GSM operators provide voice, data and Short Message Service (SMS) for subscribers. The SMS in particular, possesses some advantages when utilized as a communication interface for distribution automation, which includes easy installation and simple construction when incorporated into the Remote Terminal Unit. According to [16](NCC 2009) five Operators were licensed to provide mobile GSM services operating in dual band frequencies of 900 MHz and 1800 MHz in Nigeria. These are:

- MTN Nigeria Communications Limited
- Airtel Nigeria Limited
- Glo Mobile Nigeria Limited
- Nigerian Mobile Telecommunications Limited (M-tel)
- Emerging Markets Telecommunications Services Limited (Etisalat)

Table 1: GSM Growth in Nigeria Telecoms

Year	*2007*	*2008*	*2009*	*2010*	*2011*
GSM Lines	40,011,296	56,935,985	65,533,875	81,195,684	90,566,238

3. FIELD IMPLEMENTATION

3.1 Conceptual Indigenous Real-time Monitoring System

The conceptual frame work is based on the European protocol [17]. It consists of three levels, the process level, the bay level and the station level. The indigenous concept based on European Protocol as shown in Figure 1 was developed for Akure EPDS. The instrumentation units reside in the process level while the substation remote terminal unit formed the bay level and the station distribution central controller constitute the station level. RTU transfers this information to master station DCC using GSM.

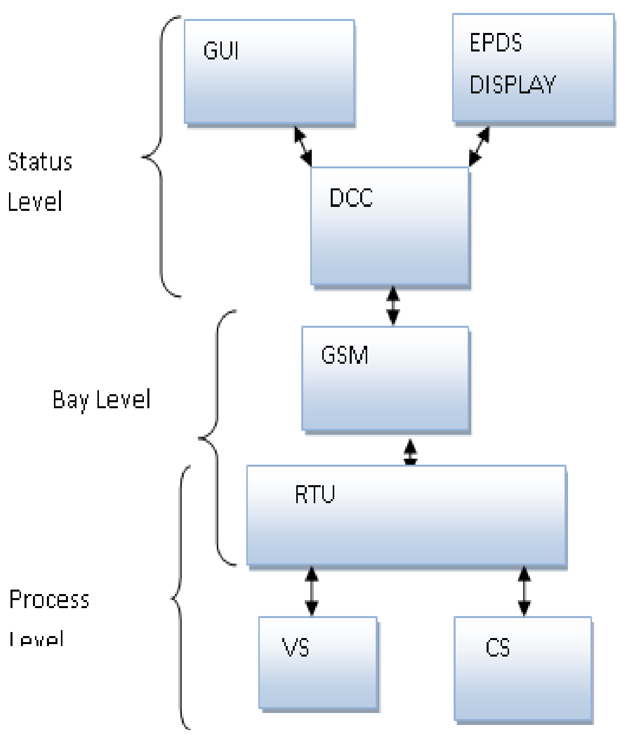

Figure 1: Block Diagram of Conceptual Distribution Network Remote Monitoring Model

Where: CS is the Current Sensor; VS is the Voltage Sensor; GUI is the Graphic User Interface; RTU the Remote Terminal Unit; GSM is the Global System for Mobile Communication and DCC- Distribution Control Centre

3.2 Choice of Communication Link between RTU and DCC

The breakdown of the GSM operators and the CDMA as well as the fixed wireless operators is shown in Figure 2 (NCC 2009). For the choice of Mobile phone provider, the following were considered:

a) SMS Rate (bulk)
b) Network coverage
c) Teledensity
d) Growth Rate

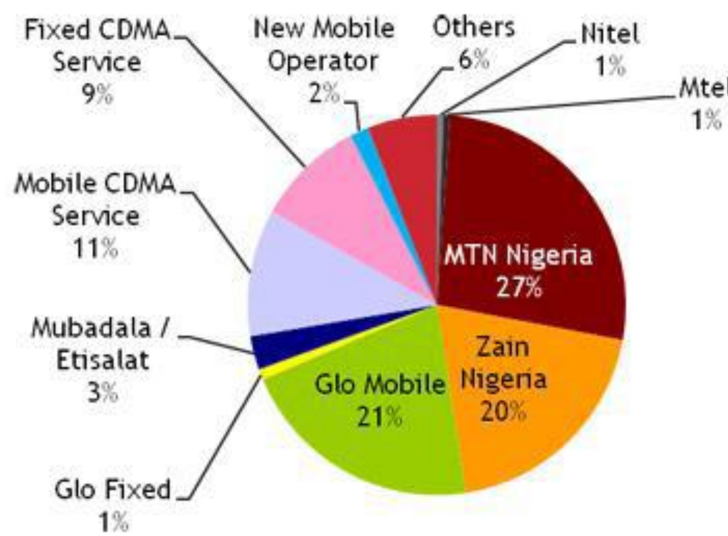

Figure2. 1: Telecommunication providers' distribution in Nigeria

3.3 Remote Terminal Unit for Data Collection

The set-up for collecting data from the selected substation is shown in Fig. 3. The RTU detect interruption and communicate the DCC via text message. The DCC received the data for further analysis.

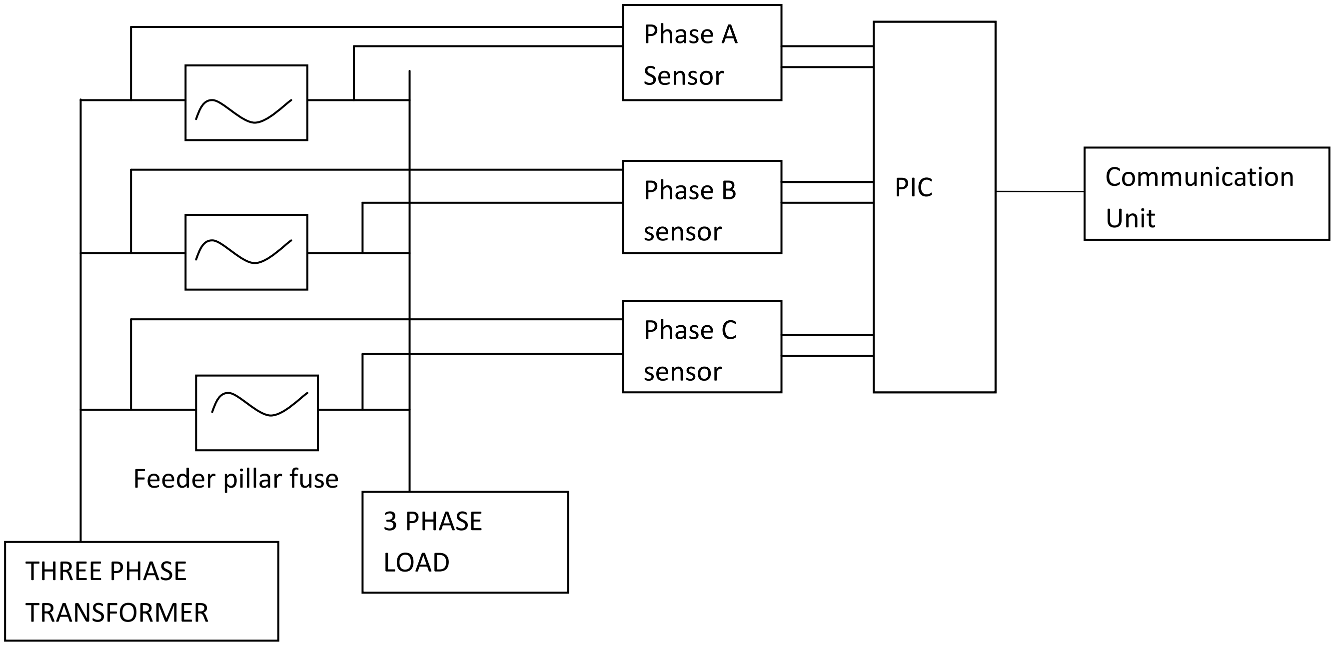

Figure 3: Block Diagram of Remote Terminal Unit

3.4 Distribution Network Faults Log

Based on the information made available by PHCN, the fault on the distribution networks are

- Over loading of 11/0.415kV transformer
- Short circuit- Over head conductors twisting and ground fault which includes Single Phase Fault (SPF), Double Phase Fault (DPF) and Three Phase Fault (TPF).
- Fuse rupture and Feeder pillar Fault(FPF)
- Open Circuit Fault which includes Upriser Cable opened and Wire Cut Fault (WCF)

3.5 Mobile Reporting (M-Reporting)

The data of faults used in the analysis and assessment were collected by the DAS on monthly bases under the accepted fault format between 2010 and 20012. The values in the tables indicate the number of times such faults occurred in a month. The report also includes the time stamp. This makes it possible to determine the total hour of interruptions in a substation.

4. DATA ANALYSIS

The faults report for the period is presented in graphical form as shown in Fig. 4 to Fig.5. These show the number of faults per month. It reveals the prevalent of Single phase

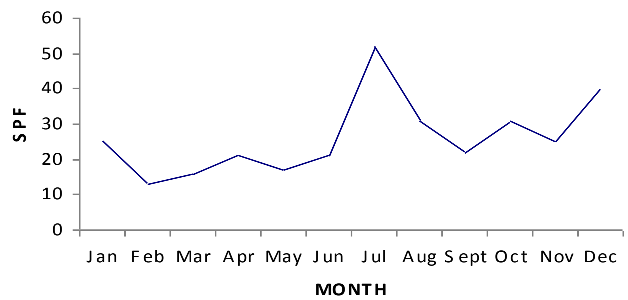

Figure 4: Single phase fault the year 2010

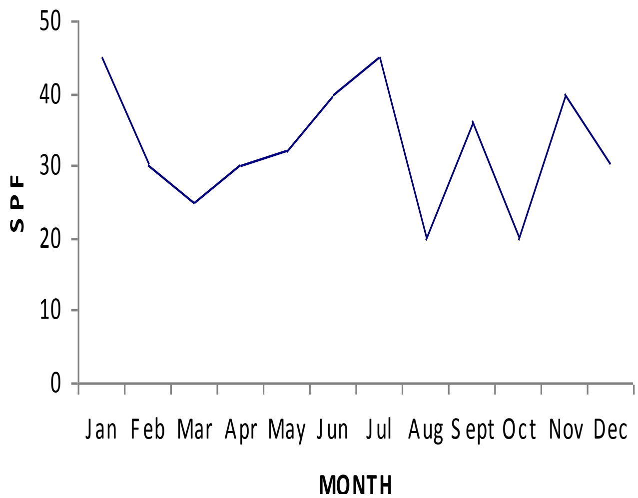

Figure 5: Single phase fault the year 2011

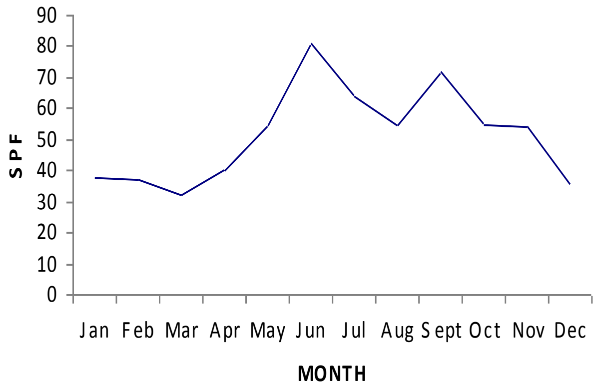

Figure 6: Single phase fault the year 2012

5. RESULT DISCUSSION

It was discovered that single phase fault accounts for more than 90% of faults associated with the network and hence SPF was presented in graphical form in Fig. 7. The software extracts the rate of equipment failure based on the information and presented in Table 3.Between 800% and 90% of the line faults are phase-to-ground faults while7% are double line faults with or without earth and which can often deteriorate to 3 phase fault and 1% involves all three-phases. Open circuit (Broken conductor) faults account for the rest.

Table 2. Average Single Phase Fault in Akure EPDS

Month	Average Number of faults/month											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Avg SFF	38.6	37	32.6	39.2	38.8	46.8	44.6	41.8	47	34.6	33.2	36.4

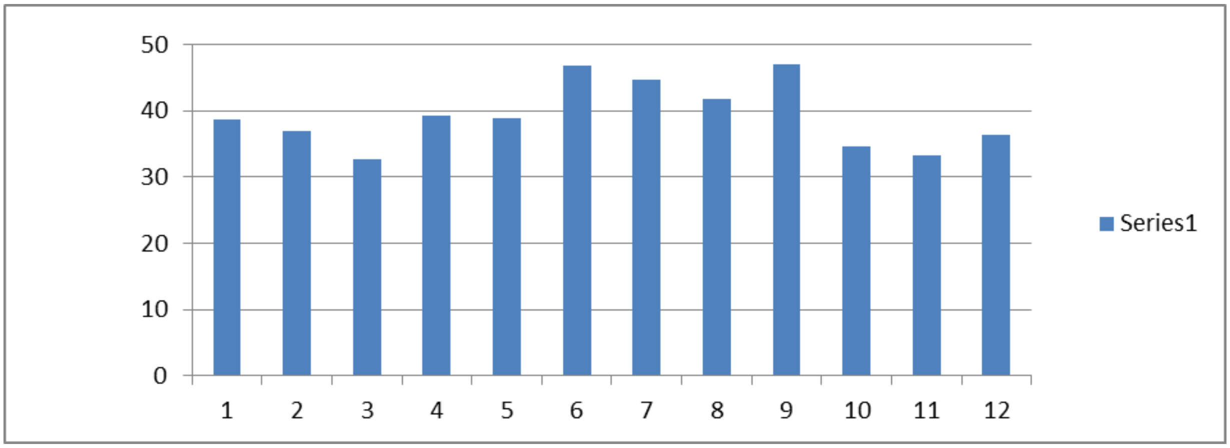

Figure 7 Average Single Phase Fault in Akure EPDS

The percentage of single fault to other type of faults is presented in Figure 8.

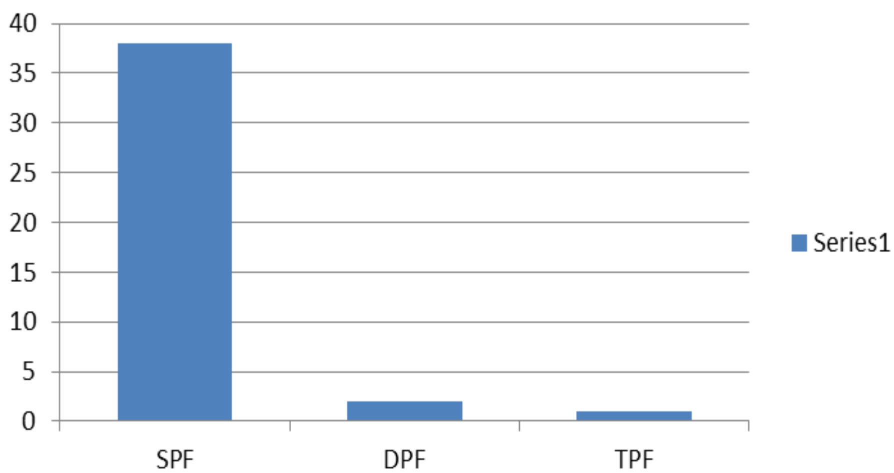

Figure 8: Percentage distribution of short circuit Faults

Table3.: Fault equipment classification

Equipment	% failure
Transformer	5
Fuse (feeder Pillars)	75
Upriser Cable	5
J&P fuse	15

6. INTERRUPTION SUMMARY

The developed software keeps record of the total hour of interruption of supply in a given substation. The report is presented in GUI. The interruption summary for substation 1 in Oyemekun 11kV feeder is shown in Figure 9.

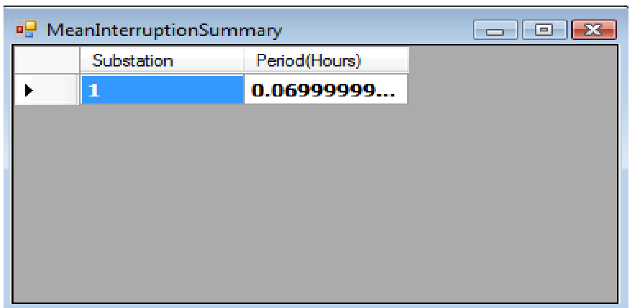

Figure 9: Interruption Summary Window

7. ESTIMATING THE SYSTEM PERFORMANCE INDEX

In each substation the number of consumers drawing power from it was obtained from the utility (PHCN). Based on the interruption summary for each substation for each year performance index was evaluated for Oyemekun substation for the year 2011 and the result is given as:

SAIFI= 2.5
SAIDI= 9.125
CAIDI = 3.7

8. CONCLUSION

The traditional method of fault record keeping in Nigeria is not only obsolete but also provides no useful information on the performance index. This makes it difficult to keep track of the system reliability over a period. The developed framework which is based on the developed template accepts the report from the fault log or from the message log data. The software resolves multiple message-log on the same fault by keeping information on fault locations, fault time stamp and restoration time. The system provides opportunity for managing faults by creating faults database, assessing the performance index for various substations and provides useful information for load management and updating material stock. The approach offers enhanced performance over the traditional approach and provides useful suggestion for improved delivery of power to consumers.

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