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EDITORIAL

Journal of Energy special issue: Papers from 5th International Colloquium "Transformer Research and Asset Management" – Materials, Components and New Technologies, Transformer Life Management

Welcome to this special issue, which is based on selected papers presented at the 5th International Colloquium "Transformer Research and Asset Management", held in Opatija, Croatia, on October 9th-12th, 2019.

The International Colloquium was organized by the Croatian CIGRÉ National Committee in cooperation with the Faculty of Electrical Engineering and Computing in Zagreb and the Centre of Excellence for Transformers in Zagreb with support from CIGRÉ A2 Study committee (Transformers). The goal of the Colloquium was to share latest research in the in the areas of distribution, power and instrument transformers. The Colloquium extended over three days. Participants from manufacturers, utilities and universities took part in discussions.

All the papers were divided into three sessions

Numerical Modeling
- Electromagnetic field
- Coupled fields
- Transients
- Numerical modeling in design, etc.

Materials, Components and New Technologies
- Insulating material
- Magnetic material
- Transformer components
- Transformer new technologies, etc.

Transformer Life Management
- Monitoring
- Diagnostics
- Failures
- Asset management, etc.

We would like to thank the authors for their contributions and the reviewers who dedicated their valuable time in selecting and reviewing these papers. We hope this special issue will provide you a valuable source of newest achievements in transformer technology.

Guest Editors

asst. prof. dr. sc. **Žarko Janić**
Končar Power Transformers
A joint Venture of Siemens AG and Končar d.d.

ass. prof. dr. sc. **Bojan Trkulja**
University of Zagreb, Croatia
Faculty of Electrical Engineering and Computing

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CO_2 footprint for distribution oil immersed transformers according to ISO 14067:2018

Vlatka Šerkinić, Marijana Majić Renjo and Viktor Ucović
Končar Distribution and Special Transformers Inc., Mokrovićeva 8, Zagreb 10090, Croatia
E-mail: vlatka.serkinic@koncar-dst.hr

Extended Abstract

In the last few decades, climate change and the global warming have emerged as important environmental issues. The cause of global warming is the increase of greenhouse gas emissions (GHG). There are several greenhouse gases responsible for global warming: water vapor, carbon dioxide (CO_2), methane, nitrous oxides, chlorofluorocarbons (CFCs) and others. They are mostly the result of the fossil fuels' combustion in cars, buildings, factories, and power plants. The gas responsible for the most of the global warming is carbon dioxide (CO_2). This increase in the greenhouse gas emissions leads to a greater interest of the consumers, board management and stakeholders in the environmental impact of their activities, products and services.

The verification of the Carbon Footprint of distribution oil immersed transformer, presented in this paper, was recognized as an opportunity for the company to understand its own environmental impact and to identify inefficiencies and opportunities within its business.

Carbon Footprint of a Product (CFP) is a rather new term closely related to the greenhouse gas emissions. The CFP is considered as a total of the greenhouse emissions generated during the life cycle of a product – that is, from raw material acquisition or generation from natural resources to a final disposal. It is described within the standard ISO 14067:2018 Carbon footprint of products – Requirements and guidelines for quantification [1]. This standard belongs to the environmental series ISO 14000 and enables the organization to demonstrate its environmental responsibility.

Life Cycle Assessment (LCA), as well as the Carbon Footprint of products together with environmental impact of the product, are shown in this paper in accordance with standard ISO 14067:2018. The LCA is a method for the quantification of the environmental impacts of individual products. It takes into account a complete life cycle, starting from a raw material production, until the product's final disposal or materials' recycling in accordance with ISO 14040 [2] and ISO 14044 [3]. Greenhouse gases are expressed in mass-based CO_2 equivalents (CO_2e), which is the unit of measurement in the ISO 14067:2018 standard. The functional unit in ISO 14067:2018 can be either a product or a service. In this paper, the functional unit was the product – oil immersed distribution transformer, in four product variations. The LCA scope used in the preparation of this study was "cradle to gate" – it covers the CFP from the acquisition of the raw materials ("cradle") up to dispatch from the factory ("gate").

The objectives of product life cycle considerations in Končar D&ST Inc. are to reduce the use of natural resources and emissions to the environment, as well as to improve social performance at different stages of the product life cycle.

By linking the economic and ecological dimension of the production, different aspects during realization of product in all phases of the life cycle come together. In this way company achieves cleaner products and processes, competitive advantage in the market and improved platform that will meet the needs of the changing business climate.

Lifecycle thinking is based on the principles of reducing environmental impacts at the beginning of product creation, giving a wider picture of material and energy flow and ultimately environmental pollution prevention. These principles are organized in Končar D&ST Inc. internally by planning and introducing cleaner manufacturing processes, environmental protection management and eco-design.

Incorporating ISO 14067:2018 into company business is recognized as an opportunity for transparent communication to interested parties, incorporating CO_2 emissions into annual reports and as a baseline information for a first step towards managing carbon emissions.

Index Terms— **greenhouse gas emissions, carbon dioxide, Carbon Footprint of a Product, Life Cycle Assessment, ISO 14067:2018 standard.**

I. INTRODUCTION

Climate change arising from anthropogenic activity has been identified as one of the greatest challenges facing the world and will continue to affect business and citizens over future decades.

Climate change has implications for both human and natural systems and could lead to significant impact on resource availability, economic activity and human wellbeing. In response, international, regional, national and local initiatives are being developed and implemented by public and private sectors to mitigate greenhouse gas (GHG) concentrations in the Earth's atmosphere as well as to facilitate adaptation to climate change. [1]

In 2008 the European Union has set three goals to be achieved by 2020 in terms of reducing greenhouse gas emissions (by 20%), share of renewable energy sources (20%) and energy efficiency improvement (20%).

Concern over climate change has stimulated interest in estimating the total amount of greenhouse gasses (GHG) produced during the different stages in the ―life cycle of goods and services ― i.e. their production, processing, transportation, sale, use and disposal. [4]

The result of GHG calculations in different stages is referred as a carbon footprint of product (CFP). In this calculation carbon footprint is the total amount of GHGs produced for a given activity, while product is any good or service that is marketed. In this context, the CFP of a product differs from the CFPs performed at the level of projects, corporations, supply chains, municipalities, nations or individuals.

Collecting the most accurate information requires a good understanding of emissions in all parts of the life cycle, usually either from raw material to factory gate (cradle to gate) or until the end of life span (cradle to grave).

Many businesses are now calculating carbon footprint of their products and services - some to meet supply chain needs to disclose carbon emissions, e.g. in sales tenders and others to actively reduce carbon footprint of production. Products and services we purchase and consume today demand a large amount of energy throughout their entire life cycle, from its production / creation to the time of their disposal at the end of the life cycle. This energy comes mainly from fossil fuels such as petroleum, coal and natural gas, all of which release carbon dioxide (CO_2) into the atmosphere, which is the cause of global warming.

Given that end users are also included in the last step - disposal and recycling, the CFP is a useful tool that involves both the manufacturer and the end user in activities to reduce GHG emissions.

As CO_2 and other greenhouse gases contribute to climate change, selecting low carbon products instead of those that have a major negative impact on the environment is one way in which a customer can make a difference.

Due to increasing demands from customer side for calculating the carbon footprint of a single transformer, a need for calculating the carbon footprint of Končar D&ST products has occurred.

The objective of this study is Life Cycle Assessment (LCA), as well as the Carbon Footprint of products together with environmental impact of the product – oil immersed distribution transformer. For the purpose of this study, standard ISO 14067:2018, as well as other standards from ISO 14000 family (ISO 14040 and ISO 14044 [2] [3]), were used as a tool to calculate the carbon footprint of Končar D&ST's product.

I.I. CFP BACKGROUND

According to the Kyoto Protocol (which was adopted in Kyoto, Japan, on 11 December 1997 and entered into force on 16 February 2005), during the first commitment period, 37 industrialized countries and the European Community committed to reduce GHG emissions to an average of five percent against 1990 levels. During the second commitment period, Parties committed to reduce GHG emissions by at least 18 percent below 1990 levels in the eight-year period from 2013 to 2020; however, the composition of Parties in the second commitment period is different from the first. [5]

As a measure of achieving these goals, the idea of developing a carbon footprint calculation mechanism that would visualize CO_2 emissions has appeared. The life cycle of the product depends on many factors such as raw material extraction, material processing, parts manufacturing, assembly, transport, product use and maintenance and end of life (disposal and recycling). (Fig. 1) [5]

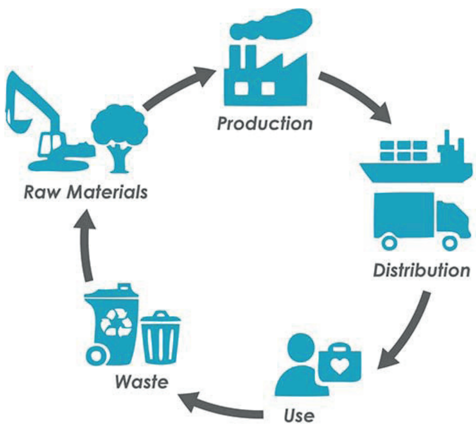

Figure 1. A life cycle of a product [5]

The carbon footprint of a product is usually calculated as the sum of the total greenhouse gas (GHG) emissions emitted at each stage of a product's life cycle by calculating its emissions, and then converting that figure to an equivalent amount of CO_2 emissions (CO_2e).

I.II. GREENHOUSE GAS EMISSION STANDARD

There are different standards regarding the monitoring of greenhouse gas emissions, which are designed to provide a framework for businesses, governments, and other entities to measure and report their greenhouse gas emissions in ways that support their missions and goals. Three of them are described in the following paragraphs.

a) Greenhouse Gas Protocol

This protocol provides standards, guidance, tools and training for business and government to measure and manage climate-warming emissions. GHG Protocol establishes comprehensive global standardized frameworks to measure and manage greenhouse gas (GHG) emissions from private and public sector operations, value chains and mitigation actions. The Greenhouse Gas Protocol provides the foundation for sustainable climate strategies and more efficient, resilient and profitable organizations. The GHG Protocol Product Standard is one of a suite of accounting tools developed by the GHG Protocol to encourage users to understand, quantify, and manage greenhouse gas emissions. [7]

b) Publicly Available Specification (PAS) 2050

Specification for the assessment of the life cycle greenhouse gas emissions of goods and services was developed by the British Standards Institution in 2008. PAS 2050 is the first consensus-based and internationally applicable standard on product carbon footprinting that has been used as the basis for the development of other standards internationally. Builds on existing international LCA standard (ISO 14044), covers all GHGs specified by the IPCC (Integrated Pollution Prevention and Control), covers whole life cycle of product (raw materials to end of life or ‘cradle to grave’), designed to be used on any product, by any company, in any geographic location. [8]

c) ISO 14067

The Carbon Footprint of a Product is the total of the greenhouse emissions generated during the life cycle assessment of a product. The GHG are considered all gaseous substances for which the IPCC has defined a global warming potential coefficient. They are expressed in mass-based CO_2 equivalents (CO_2e), which is the unit of measurement in ISO 14067.

A carbon footprint and life cycle assessment (LCA) is used to systematically record and analyze the impact on the environment throughout the entire life cycle of a product or service. This involves an end-to-end analysis of the product or service. The analysis considers all raw materials, transports, production processes, usage and disposal of the product. A carbon footprint at product level is a special application of the LCA methodology that specifically focuses on greenhouse gas emissions. [1]

I.III. LIFE CYCLE ASSESMENT

A Product Carbon Footprint is based on a life cycle assessment (LCA), but focuses on a single issue which is global warming. An LCA shows where the environmental impact in the overall chain takes place which can serve as an opportunity to improve a certain process or product parts. Eventually, this can lead towards savings in, for example raw materials, energy use and total costs, and to a more sustainable product which can be used as promotion point when selling the product.

According to ISO 14040 an LCA study consists of four main phases [2]:

Step 1: Defining the goal and scope of the study.

Step 2: Making a model of the product life cycle with all the environmental inputs and outputs. This data collection effort is usually referred to as life cycle inventory (LCI).

Step 3: Understanding the environmental relevance of all the inputs and outputs. This is referred to as life cycle impact assessment (LCIA).

Step 4: The interpretation of the study.

The principles of the LCA standard were followed when carrying out the case studies presented in this report. The four phases of LCA are presented in Figure 2.

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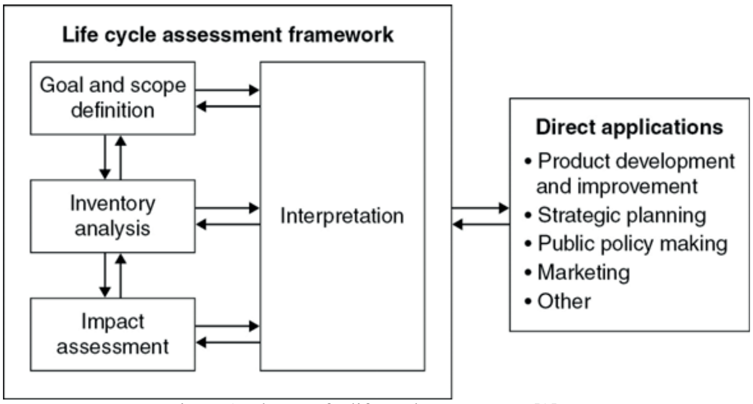

Figure 2. Phases of a life cycle assessment [2]

II. EXPERIMENTAL

The overall goal of conducting a CFP study is to calculate the potential contribution of a product to global warming potential expressed as CO_2e by quantifying all significant GHG emissions and removals over the product's life cycle or selected processes, in line with cut-off criteria. [1]

The CFP study can be conducted according to several types of LCA methodology, for instance:

- Cradle-to-grave – full life cycle assessment from resource extraction ('cradle') to use phase and disposal phase ('grave');
- Cradle-to-gate is an assessment of a partial product life cycle from resource extraction (cradle) to the factory gate (i.e., before it is transported to the consumer);
- Cradle-to-cradle (or closed loop production) – a specific kind of cradle-to-grave assessment, where the end-of-life disposal step for the product is a recycling process.

In this CFP study report cradle-to-gate methodology was used. This means the product was studied from extraction of raw materials to its production. The goal of this project was to produce validated environmental data for oil immersed transformers, in order to get insight in their environmental performance. International Electrotechnical Vocabulary defines a transformer as a static piece of apparatus with two or more windings which, by electromagnetic induction, transforms a system of alternating voltage and current into another system of voltage and current, usually of different values and at the same frequency for the purpose of transmitting electrical power. [9] Distribution Transformers are used in distribution networks in order to transmit energy from the medium voltage (MV) network to the low voltage (LV) network of the consumers. [10]

An oil immersed distribution transformer is composed of the following main components: transformer core made from special grade magnetic steel; low voltage winding made from aluminum coil; high voltage winding made from aluminum wire; tank and cover made from low carbon steel; transformer oil (mineral oil or synthetic ester); insulation components made from paper and pressboard; some store-bought components, such as tap changer, bushings etc. Most of the raw materials (magnetic steel, aluminum coil and wire, transformer oil) are produced in a way specific for a transformer industry and will not be explained here.

In the production of Končar D&ST, raw materials are machined and assembled, together with store-bought components, in a complete product: the magnetic steel is slit, cut and stacked into transformer core; aluminum coil and aluminum wire, together with diamond-dotted insulation paper are transformed into low voltage windings and high voltage winding, respectively. Windings are assembled onto the core, connected with cover and then tanked. So prepared semi-product is dried in a low-frequency heating (LFH) plant, vacuumed and filled with transformer oil.

Figure 3 displays a schematic overview of the production process, including system boundaries. All relevant and known processes and materials have been included.

Standard ISO 14067 asks for unit declaration together with cradle-to-gate boundaries which in this case is the same for all types of transformers included in the study.

Declared unit: the cradle-to-gate CO_2 eq. emissions of oil immersed transformer.

Study was performed for specific products from one plant and one manufacturer and data was collected for the year 2018.

The carbon footprint study includes cradle-to-gate CO_2e emission data for the following transformers, produced at Končar D&ST Inc. in Zagreb, Croatia [11], shown in Figures 4-6:

- Object 1 (400 kVA);
- Object 2 (400 kVA);
- Object 3 (400 kVA);
- Object 4 (630 kVA).

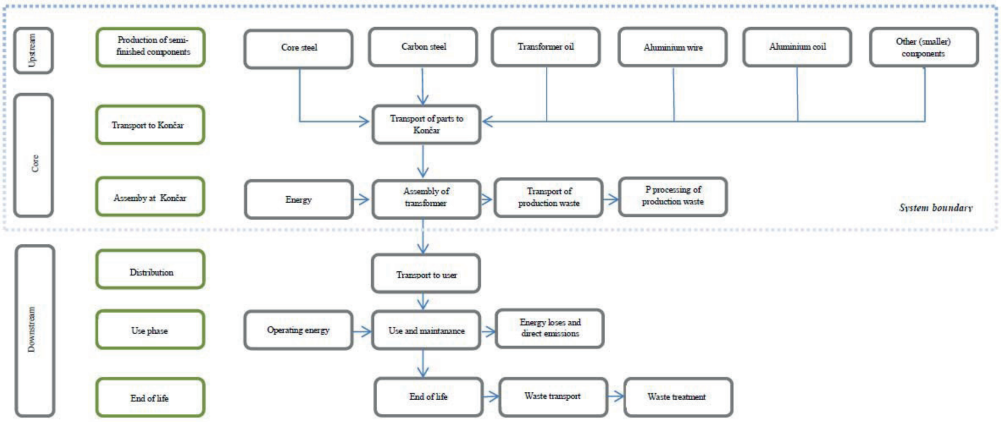

Figure 3. Schematic overview of the Končar D&ST's production

Figure 4. Visualization of Object 1, Object 2, Object 3

Figure 5. Visualization of Object 1, Object 2, Object 3

Figure 6. Visualization of Object 4

II.I. INVENTORY ANALYSIS

Life cycle inventory analysis is a phase of a life cycle assessment involving the compilation and quantification of inputs and outputs for a product throughout its life cycle. [1]

Inventory was discussed for the four types of transformers in a way that all components from the bill of materials per each transformer, weighing more than 1 kg, were taken into account. All transformer components were analyzed according to the name of the component, data type, reference process, weight and the main part to which the component belongs.

Main components covered with this study were: aluminum coil, aluminum wire, carbon steel, core steel and transformer oil. LCA software used in this CFP study report was SimaPro 9.0.

Selection of processes that covers 80% of the total CO_2e emissions was made and primary data was collected for these processes.

Electricity consumption at Končar D&ST includes the following processes:

- Lines for cutting transformer sheets (slitting and cutting);
- Preparation of the insulation parts;
- Preparation of the windings;
- Production and assembly;
- Drying of active parts (core and windings);
- Manipulation with electric forklifts;

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As well as:

- Testing station;
- Lighting;
- Ventilation;
- Compressed air;
- Offices.

The origin of the electricity used by Končar D&ST in 2018 was retrieved from the website of HEP, Končar D&ST's power supplier:

- 42% hydroelectric power plants;
- 17% thermal power plants;
- 17% renewable energy sources;
- 14% nuclear power plants;
- 10% unknown.

Data on production waste at Končar D&ST is indicted per material and type of transformer. Types of wastes that are generated in Končar D&ST which were analyzed in this study are core sheets steel, aluminum and waste transformer oil. [11]

III. RESULTS AND DISCUSSION

In this phase of a CFP study, the potential climate change impact of each GHG emitted and removed by the product system was calculated by multiplying the mass of GHG released or removed by the 100-year GWP (Global warming potential) given by the IPCC in units of kg CO_2e per kg emission. [1]

Steel for the core, aluminum wire and cold-rolled steel make up the top three of materials with the largest contribution to the total CO_2e emissions.

Table I. shows total emissions expressed in kilograms of CO_2 equivalents. [11]

TABLE I. Total by carbon source in kg CO_2 eq.

Transformer	Total kg CO_2eq.
OBJECT 1	4673
OBJECT 2	4915
OBJECT 3	5003
OBJECT 4	6736

The carbon footprint of the transformers covered by the study ranges from 4676 kg CO_2 eq. for the Object 1 to 6736 kg CO_2 eq. for Object 4. This difference can be explained by the total amount of materials used in the different types of transformers (different weight of core, tank etc.). Due to small differences in design and functionality, the Object 1 has a slightly lower carbon footprint. Also, there is a slight difference in carbon footprint between the Object 1 and the other two 400 kVA transformers, which was mostly caused by materials used in the windings.

The larger carbon footprint of the Object 4 (630 kVA) compared to the other three transformers can be explained by its total mass. Compared to the 400 kVA transformers, the Object 4 is considerably heavier because more material is used for production. When calculating the emissions in kg CO_2 eq. per kg material used for the different transformers, results for the Object 2, Object 3 and Object 1 are that approx. 3,8 kg CO_2e per kg of used material. Whereas the Object 4 has a carbon footprint of 4,0 kg CO_2e per kg of used material. [11]

Data for each unit process within the systems boundary can be classified under major groups [2]:

- Energy inputs, raw material inputs, ancillary inputs, other physical inputs;
- Products, co-products and waste;
- Emissions to air, discharges to water and soil;
- Other environmental aspects.

The quality of CFP data relies strongly on the quality of input data. According to standard ISO 14067 it is preferable to use data derived from company's own processes (i.e. primary data). In addition to that, raw materials from suppliers were analyzed considering they can strongly influence the CFP. In this CFP study report, authors strived to use primary data from suppliers of the main parts. Besides that, they relied on industry average data where no supplier-specific information was available.

Končar D&ST provided all data based on the bills of materials and technical drawings of the various transformers which displayed composition and the amounts of used materials. [11]

IV. CONCLUSION

Measures to reduce the carbon footprint of the products covered by the study can be implemented in several ways. Končar D&ST is considering three possible options.

One way is to influence the production process in Končar D&ST through various measures (product design or development, alternative materials). Since 2% of the total CO_2 impact calculated in this study is the contribution of the processes at the Končar D&ST production site, this would be almost half of the contribution to the total 5% reduction which was Končar D&ST's CFP reduction goal.

Another way of CFP reduction is through material purchasing, since other 98% of the total CFP is a contribution that comes from suppliers of the materials. These improvement measures can be done in one of the following ways:

- Communicate with the suppliers with high CO_2 contribution about the energy sources that they use in their process – e.g. energy generated in a conventional way could be replaced by some form of renewable energy;
- Request from suppliers to use a certain type of fuel when transporting goods to Končar D&ST (e.g. EURO 5, EURO 6);
- Suggest to tank suppliers to buy raw materials produced in arc furnaces (which use a large content of raw materials from secondary sources – recycled) and not in conversion furnaces (large content of raw materials from primary sources), and therefore adopt a procurement plan that benefits a supplier who uses a large content of raw materials from secondary sources;
- In the future, buy material in a greater percentage than before from a major supplier who has a smaller total carbon footprint.

Third goal option to reduce CO_2 footprint is tree planting since trees and green plants take in carbon dioxide for photosynthesis and in this way should reduce CO_2. Tree planting these days is becoming an increasingly popular tool to combat climate change. New analyses show that there is enough space in the world's existing parks, forests and abandoned land to plant 1,2 trillion additional trees, which would have the CO_2 storage capacity to cancel out a decade of carbon dioxide emissions.

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Uncertainty estimation of low voltage LI measurements with recurrent surge generator and oscilloscope

Zdenko Godec[1], Vjenceslav Kuprešanin[1] and Filip Razum[1]
[1]Končar – Electrical Engineering Institute, Fallerovo Šetalište 22, HR-10000 Zagreb, Croatia
E-mail: vkupresa@koncar-institut.hr

***Abstract*— Low voltage LI measurement with recurrent surge generator and oscilloscope is a method used for investigating LI distribution in transformer windings or in model prototypes for various conditions. In the paper, the procedure for measurement uncertainty estimation of characteristic voltage and time quantities is given. The procedure is similar to the procedure given in the IEC 60076-2 standard for high voltage testing, but it is fully adapted to low voltage measurement with recurrent generator and oscilloscope. For the purpose of reducing the measurement uncertainties and the measurement time, a new procedure is proposed.**

***Index Terms*—Low voltage lightning impulse measurement, measurement uncertainty, complete measurement result, stability, repeatability, nonlinearity**

I. INTRODUCTION

Low voltage lightning impulse (LI) measurement with recurrent surge generator and oscilloscope is a non-destructive, widely accepted method used in the transformer industry. The method is primarily used for investigating LI voltage distribution in transformer windings or in model prototypes for various impulse voltage conditions, giving useful information for proper insulation design. In addition, it can be used for estimating the impulse circuit parameters for LI testing or as a control for transient calculation tools. In this method, the recurrent surge generator acts as a low voltage equivalent of the high voltage impulse generator, and the oscilloscope is used for measurement and analysis. As an input voltage, most often standard lightning-impulse voltage, described as 1,2 µs/50 µs impulse, or standard chopped lightning impulse voltage (chopping in range 2 µs to 5 µs) is used. The main measurement results are the input voltage with its parameters (U_p – peak voltage (V), T_1 – front time (µs), T_2 – time to half-value (µs), T_c – time to chopping (µs), ß' – relative overshoot magnitude (%)) and the response voltages measured in different points, regularly expressed in percentage of the input voltage.

In the paper, the uncertainty estimates for low voltage parameters measured by the usual procedure are given. Usual procedure assumes simultaneous recording of the input (reference) voltage and one or more response voltages. Based on the uncertainty component analysis of the usually used procedure, an improved measurement procedure is proposed. The new procedure reduces both the measurement uncertainties and the time required to complete measurements.

A new software for data acquisition and lightning impulse analysis is developed in *National Instruments™ Labview* programming language. Impulse parameters are calculated according to the procedure given in [1], and the algorithm is verified based on [2]. All measurement results, presented in the tables, were obtained with this application. Although the procedure for determination of impulse voltage parameters is primarily introduced for high voltage impulse testing, it is reasonable to apply the same algorithm for low voltage measurements, making it a better simulation and control tool.

II. BLOCK DIAGRAM AND MATHEMATICAL MODEL OF MEASUREMENT

In Fig. 1., a simplified block diagram of measurement is shown.

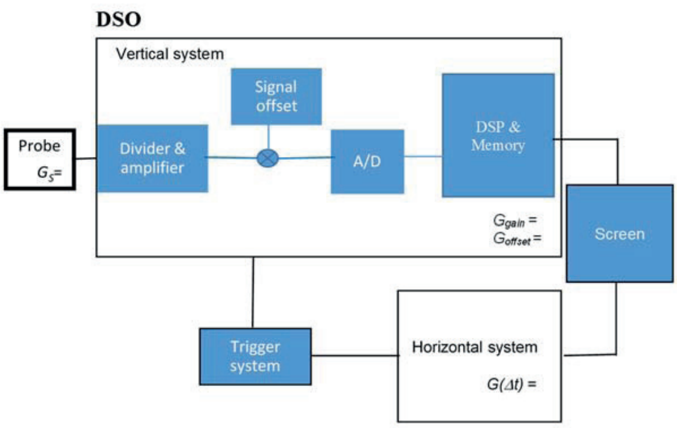

Figure 1: Simplified block diagram of the measurement system (digital oscilloscope + probe).

A voltage to be measured is applied to the input of the probe. The probe output is connected to the input of the digital oscilloscope. On the oscilloscope screen, voltage V_M and time interval Δt are read (graphically or digitally):

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$$V_M = k_S \cdot k_{VOS} \cdot V = n_V \cdot d_V \tag{1}$$

$$\Delta t = n_t \cdot d_t \tag{2}$$

Symbol k_S represents measuring probe scale factor (mostly voltage damping), k_{VOS} is a factor that includes digital signal processing (DSP) of an oscilloscope vertical system, n_V is a number of divisions in the vertical direction and d_V is (adjusted) sensitivity of the vertical scale, expressed in volts per division (V/div). The sensitivity in vertical direction also includes the nominal factor of the measuring probe, so that the oscilloscope directly shows (graphically and digitally) the measured voltage V_M.

Further, n_t is a number of divisions (div) in the horizontal direction, and d_t is (adjusted) sensitivity of the horizontal scale, expressed in seconds per division (s/div).

III. STANDARD MEASUREMENT UNCERTAINTY OF VOLTAGE

Based on the first part of the mathematical model (1), the expression for standard measurement uncertainty of peak-to-peak voltage is derived:

$$u(V_M)_{\%} = \sqrt{[u(k_S)_{\%}]^2 + [u(k_{VOS})_{\%}]^2 + u^2_{\%res}} \tag{3}$$

where $u_{\%res}$ is the uncertainty component due to the oscilloscope finite resolution.

Standard measurement uncertainties are estimated based on specified error limits (accuracy) [3].

For measuring probes, percentage error limits with respect to measured voltage are given. E.g., for probe type P6139B [4] error limits are:

$$G_{\%S} = \pm 0{,}5\ \% \tag{4}$$

Percentage standard uncertainty of voltage at the output of measuring probe is then [3]:

$$u(k_S)_{\%} = \frac{G_{\%S}}{\sqrt{3}} \tag{5}$$

The way of specifying the error limits for the oscilloscopes is not standardized, so the form of specification mostly depends on the manufacturer.

For the vertical system of the oscilloscope TEKTRONIX TDS7104, the next specification is given [5]:

a) Error limit of the attenuation (scale factor) with respect to the measured value:

$$G_{\%gain} = \pm 1\ \% \tag{6}$$

consequently, the absolute error limit is:

$$\dot{G}_{gain} = \pm \frac{1}{100} \cdot n_V \cdot d_V \tag{7}$$

n_v is measured number of divisions, and d_v is sensitivity in the vertical direction (V/div).

b) Absolute error limit of the offset:

$$\dot{G}_{Offset} = \pm\left(0{,}25\ \% \times \left|\left(Offset - Position \text{ x} \frac{\text{V}}{\text{div}}\right)\right| + 150\ m\text{V} + 0{,}1 \text{ div x} \frac{\text{V}}{\text{div}}\ setting\right) \tag{8}$$

where *Offset* is adjusted offset voltage V_{Offset} , *Position* is a channel reference position with respect to the vertical scale central line (div), n_{Vc} , multiplied with adjusted sensitivity d_V (V/div).

Absolute error limit of the offset can be more clearly stated as follows:

$$\dot{G}_{Offset} = \pm\left[0{,}25\ \% \times \left|\left(V_{Offset} - n_{Vc} \cdot d_V\right)\right| + 150\ m\text{V} + 0{,}1 \text{ div} \times d_V\right] \tag{9}$$

Error limit for each of the voltage samples (measuring points) is defined as:

$$\dot{G}(V) = \pm\Big[1\% \times \Big|reading - \left(Offset - Position \text{ x} \frac{\text{V}}{\text{div}}\right)\Big| + Offset\ Accuracy + \\ + 0{,}13 \text{ div x} \frac{\text{V}}{\text{div}}\ setting + 0{,}6 \text{ mV}\Big] \tag{10}$$

For this type of the oscilloscope, absolute error limit of peak-to-peak voltage (Vpp) is also defined:

$$\dot{G}(V_{pp}) = \pm\left[1\ \% \times |reading| + 0{,}26 \frac{V}{\text{div}} setting + 1{,}2 \text{ mV}\right] \tag{11}$$

or more clearly:

$$\dot{G}(V_{pp}) = \pm\left[\frac{1\ \%}{100\ \%} \times |n_V \cdot d_V| + 0{,}26 \text{ div} \cdot d_V + 1{,}2 \text{ mV}\right] \tag{12}$$

Absolute standard uncertainty of measured voltage is then:

$$\dot{u}\ (k_{VOS}) = \frac{\dot{G}(V_{pp})}{\sqrt{3}} \tag{13}$$

with percentage standard uncertainty being equal to:

$$u(k_{VOS})_{\%} = \frac{\dot{u}\ (k_{VOS})}{n_V \cdot d_V} 100\ \% \tag{14}$$

Finally, percentage standard uncertainty of voltage measurement (probe + oscilloscope) is estimated as:

$$u(V_M)_{\%} = \sqrt{\left[\frac{G_{\%S}}{\sqrt{3}}\right]^2 + \left[\frac{100\ \%}{n_V \cdot d_V} \cdot \frac{\dot{G}(V_{pp})}{\sqrt{3}}\right]^2 + u_{\%res}^2} \tag{15}$$

and the absolute standard uncertainty is:

$$\dot{u}(V_M) = \frac{u(V_M)_{\%}}{100\ \%} \cdot V_M \tag{16}$$

Component of the standard uncertainty (absolute) due to the oscilloscope finite resolution is equal:

$$\dot{u}_{res} = \frac{\dot{R}}{2 \cdot \sqrt{3}} = \frac{d_V \cdot 10 div}{2 \cdot \sqrt{3} \cdot 2^x} \tag{17}$$

where $\dot{R}$ is the resolution, and x is the effective number of bits (ENOB).

Percentage component of the standard uncertainty due to the finite resolution is calculated as:

$$u_{\%res} = \frac{10 \cdot 100\ \%}{2 \cdot \sqrt{3} \cdot 2^x \cdot n_v} = \frac{10 \cdot d_V \cdot 100\ \%}{2 \cdot \sqrt{3} \cdot 2^x \cdot V_M} \tag{18}$$

IV. STANDARD MEASUREMENT UNCERTAINTY OF VOLTAGE RATIO

As a rule in low voltage LI measurement reports, peak values of the measured response voltages are expressed in percentage of the applied lightning impulse V_0 (its peak value):

$$v_{\%i} = \frac{V_i}{V_0} 100\ \% \tag{19}$$

The standard measurement uncertainty of voltage ratio (%) is:

$$u(v_{\%i})_{\%} = \sqrt{[u(V_i)_{\%}]^2 + [u(V_0)_{\%}]^2} \tag{20}$$

Since the voltage ratio is a quantity given in percentage, it is more convenient to calculate the absolute standard uncertainty:

$$\dot{u}(v_{\%i}) = \frac{u(v_{\%i})_{\%}}{100\ \%} \cdot v_{\%i} \tag{21}$$

V. STANDARD MEASUREMENT UNCERTAINTY OF TIME INTERVAL

Error limits of measured time interval are also specified in different ways by different manufacturers.

Expression (22) explains the relationship among different characteristic time quantities of the oscilloscope:

$$f_U = \frac{RL}{\Delta t_D} \tag{22}$$

where symbols are:

f_U – sample rate in S/s (Samples per second),

RL – record length expressed as the number of samples stored in memory,

Δt_D – time domain or range in seconds (equal to number of divisions in horizontal direction (n_{tD}) multiplied with scale sensitivity d_t; n_{tD} is mostly equal 10,

d_t – sensitivity of the horizontal (time) scale in s/div.

Time resolution is better with higher sampling frequency (t_{sr} = 1/(Sample rate)). Therefore, the time sensitivity and the length of the record should be adjusted to achieve the highest possible sampling frequency with noise (interferences) still being acceptable.

For the oscilloscope Tektronix TDS7104 the manufacturer for the time interval measurement ($\Delta t = DT$) specifies the following expression for the error limit (DTA = Delta Time Accuracy):

$$DTA = \dot{G}(\Delta t) = \pm\left(15\ ppm\ x\ |reading| + \frac{0{,}3}{real\ time\ sample\ rate}\right) \tag{23}$$

The absolute standard uncertainty (in seconds) is estimated as:

$$\dot{u}(\Delta t) = \frac{\dot{G}(\Delta t)}{\sqrt{3}} \tag{24}$$

and the percentage standard uncertainty of time interval Δt is:

$$u(\Delta t)_{\%} = \frac{\dot{u}(\Delta t)}{\Delta t} \cdot 100\% \tag{25}$$

VI. INFLUENCING FACTORS

The IEC standard [1] specifies an expression for estimating the extended relative measurement uncertainty of a measured voltage V_M which contains a number of components of measurement uncertainty caused by different influencing factors:

$$U_M = k \cdot u_M = 2\sqrt{u_{cal}^2 + \sum_{i=0}^{N} u_{Bi}^2} \quad (26)$$

u_{cal} is the standard uncertainty of scale factor of the approved measuring system determined by the calibration procedure, u_{Bi} is the contribution to the combined standard uncertainty of the scale factor of the approved measuring system, caused by the i-th influence quantity and evaluated as a Type B contribution. These contributions are related to normal use of the approved measuring system, and arise from non-linearity, short-term and long-term instabilities, etc. and are determined by additional measurements or are estimated from other data sources. Other significant influences shall be taken into account, e.g. resolution of instrument display – if it is significant.

Effect of nonlinearity is expressed by relative standard uncertainty u_{B0}, effect of extension of the validity of the scale factor is expressed by u_{B1} (not relevant in our measurements), effect of dynamic behavior (amplitude/frequency response) is expressed by u_{B2}, effect of short-term stability by u_{B3}, effect of long-term stability by u_{B4}, effect of ambient temperature by u_{B5}, proximity effect by u_{B6}, and software effect by u_{B7}.

All of the above-listed uncertainty components are covered by the specified error limits of the measuring probe and the oscilloscope, provided that the measurements are made in the temperature range from 10 °C to 45 °C [5] and that a negligible proximity effect is provided during the measurement. Only software effect uncertainty u_{B7}, upper limits of which are given in table 3 in [2] and abbreviated here in table I., is not covered by the error limits of the measuring channels.

TABLE I. STANDARD UNCERTAINTY CONTRIBUTIONS OF SOFTWARE ($u_{\%soft}$) TO THE OVERALL UNCERTAINTY ACCORDING TO THE SIMPLIFIED PROCEDURE [2]

Inpulse group/evaluation algorithm	*V*/%	*ß*/%	T_1/%	T_2/%
LI	0,058	0,58	1,2	0,58
LIC	0,58	0,58	1,2	1,2
SI	0,29	-	2,9	1,2

It means that for the total (overall) uncertainty, to previously calculated standard uncertainties (chapters II to V) corresponding uncertainties from table I. should be added.

VII. COMPLETE MEASUREMENT RESULT OF VOLTAGE RATIO AND TIME INTERVAL WITH STANDARD PROCEDURE

A. *Complete measurement result of voltage ratio*

Nowadays, it is common for the complete measurement result to be expressed by the extended measurement uncertainty with k = 2. Extended measurement uncertainty increases the confidence that the true value of a measured quantity is within the range of values determined by the measured value and expanded uncertainty (approximately 95% for k = 2) [3].

The complete measurement result for voltage ratio is then:

$$v_{\%i} = v_{\%i} \pm 2 \cdot \dot{u}_{\mathrm{T}}(v_{\%i}) \quad (27)$$

In the final result, the expanded measurement uncertainty is rounded to two significant digits, and the standard measurement uncertainties (as intermediate results) are rounded to four significant digits.

The total (overall) uncertainty of the voltage ratio (the response voltage expressed as a percentage of the applied voltage) is estimated by the expression:

$$\dot{u}_{\mathrm{T}}(v_{\%i}) = \sqrt{\dot{u}(v_{\%i})^2 + 2 \cdot u_{\%\mathrm{soft}}^2} \quad (28)$$

EXAMPLE 1

With the HAEFELY Type 481 generator [6], a peak-to-peak voltage of 300,3 V was applied. The measurement was performed by TEKTRONIX P6139B passive probe [4] and the TEKTRONIX TDS7104 oscilloscope [5]. Offset was 0 V, and the sensitivity of the vertical system was adjusted to $d_V = 50$ V/div.

The response peak to peak voltage between two points was 46,66 V, measured by another measuring channel (oscilloscope + measuring probe) with vertical sensitivity $d_V = 10$ V/div.

The measurement uncertainty of the response voltage ratio should be estimated.

According to (12), the error limit of the oscilloscope when measuring the applied voltage (300,3 V) is:

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$$\dot{G}(V_{pp}) = \pm\left[\frac{1\,\%}{100\,\%} \times |n_V \cdot d_V| + 0{,}26\ \text{div} \cdot d_V + 1{,}2\ \text{mV}\right] =$$

$$= \pm\left[\frac{1\,\%}{100\,\%} \cdot 300{,}3 + 0{,}26 \cdot 50 + 1{,}2\ \text{mV}\right] = 16{,}00\ \text{V}$$

The absolute standard measurement uncertainty of voltage measured by the oscilloscope is estimated according to (13):

$$\dot{u}\,(k_{VOS}) = \frac{\dot{G}(V_{pp})}{\sqrt{3}} = \frac{16{,}00}{\sqrt{3}} = 9{,}238\ \text{V}$$

and the percentage standard uncertainty is (14):

$$u(k_{VOS})_{\%} = \frac{\dot{u}\,(k_{VOS})}{n_V \cdot d_V} 100\,\% = \frac{9{,}238}{300{,}3} 100\,\% = 3{,}078\,\%$$

Component of the uncertainty due to the oscilloscope finite resolution (expressed in percentage) is estimated by the expression (18):

$$u_{\%res} = \frac{10 \cdot d_V \cdot 100\,\%}{2 \cdot \sqrt{3} \cdot 2^x \cdot V_M} = \frac{10 \cdot 50 \cdot 100\,\%}{2 \cdot \sqrt{3} \cdot 2^{8,7} \cdot 300{,}3} = 0{,}1156\,\%$$

According to the manufacturer's specification, the effective number of bits (ENOB) of the oscilloscope type TDS7104 is x=8,7 when using Hi-Res acquisition.

The percentage standard uncertainty of measured applied voltage (300,3 V; probe + oscilloscope) is estimated by the expression (15):

$$u(V_M)_{\%} = \sqrt{\left[\frac{G_{\%S}}{\sqrt{3}}\right]^2 + \left[\frac{100\,\%}{n_V \cdot d_V} \cdot \frac{\dot{G}(V_{pp})}{\sqrt{3}}\right]^2 + u^2_{\%res}} =$$

$$= \sqrt{\left[\frac{0{,}5}{\sqrt{3}}\right]^2 + \left[\frac{100\,\%}{300{,}3} \cdot \frac{16{,}00}{\sqrt{3}}\right]^2 + 0{,}1156^2} = 3{,}092\,\%$$

The same procedure applies when estimating the measurement uncertainty of the response voltage (46,66 V). According to (12), the error limit of the oscilloscope when measuring the response voltage is:

$$\dot{G}(V_{pp}) = \pm\left[\frac{1\,\%}{100\,\%} \times |n_V \cdot d_V| + 0{,}26\ \text{div} \cdot d_V + 1{,}2\ \text{mV}\right] =$$

$$= \pm\left[\frac{1\,\%}{100\,\%} \cdot 46{,}66 + 0{,}26 \cdot 10 + 1{,}2\ \text{mV}\right] = 3{,}068\ \text{V}$$

The absolute standard uncertainty of the oscilloscope due to its error limit is (13):

$$\dot{u}\,(k_{VOS}) = \frac{\dot{G}(V_{pp})}{\sqrt{3}} = \frac{3{,}068}{\sqrt{3}} = 1{,}771\ \text{V}$$

and the percentage uncertainty is (14):

$$u(k_{VOS})_{\%} = \frac{\dot{u}\,(k_{VOS})}{n_V \cdot d_V} 100\,\% = \frac{1{,}771}{46{,}66} 100\,\% = 3{,}796\,\%$$

Percentage component of the uncertainty due to the oscilloscope finite resolution is equal to (18):

$$u_{\%res} = \frac{10 \cdot d_V \cdot 100\,\%}{2 \cdot \sqrt{3} \cdot 2^x \cdot V_M} = \frac{10 \cdot 10 \cdot 100\,\%}{2 \cdot \sqrt{3} \cdot 2^{8,7} \cdot 46{,}66} = 0{,}1488\,\%$$

Percentage standard uncertainty of response voltage measurement (46,66 V; probe + oscilloscope) is (15):

$$u(V_M)_{\%} = \sqrt{\left[\frac{G_{\%S}}{\sqrt{3}}\right]^2 + \left[\frac{100\,\%}{n_V \cdot d_V} \cdot \frac{\dot{G}(V_{pp})}{\sqrt{3}}\right]^2 + u^2_{\%res}} =$$

$$= \sqrt{\left[\frac{0{,}5}{\sqrt{3}}\right]^2 + \left[\frac{100\,\%}{46{,}66} \cdot \frac{3{,}068}{\sqrt{3}}\right]^2 + 0{,}1488^2} = 3{,}810\,\%$$

Percentage standard uncertainty of voltage ratio is estimated by the expression (20):

$$u(v_{\%i})_{\%} = \sqrt{[u(V_i)_{\%}]^2 + [u(V_0)_{\%}]^2} = \sqrt{3{,}092^2 + 3{,}810^2} = 4{,}907\,\%$$

with the absolute standard uncertainty of voltage ratio being (21):

$$\dot{u}(v_{\%i}) = \frac{u(v_{\%i})_{\%}}{100\,\%} \cdot v_{\%i} = \frac{4{,}907\,\%}{100\,\%} \cdot \frac{46{,}66}{300{,}3} 100\,\% = 0{,}7624\,\%$$

Total (overall) uncertainty of voltage ratio (i.e. the response voltage expressed in a percentage of applied voltage) is estimated according to (28):

$$\dot{u}_{\mathrm{T}}(v_{\%i}) = \sqrt{\dot{u}(v_{\%i})^2 + 2 \cdot u^2_{\%\mathrm{soft}}} = \sqrt{0{,}7624^2 + 2 \cdot 0{,}058^2} = 0{,}7668\,\%$$

Complete measurement result of voltage ratio is according to (27):

$$v_{\%i} = v_{\%i} \pm 2 \cdot \dot{u}_{\mathrm{T}}(v_{\%i}) = \frac{46{,}66}{300{,}3} 100\,\% \pm 2 \cdot 0{,}7668\,\% = \{15{,}5 \pm 1{,}5\}\,\%$$

B. Complete measurement result of time interval

The overall percentage uncertainty of time interval is estimated by:

$$u_{\mathrm{T}}(\Delta t)_{\%} = \sqrt{u(\Delta t)_{\%}^2 + 2 \cdot u_{\%\mathrm{soft}}^2} \tag{29}$$

and the complete measurement results of time interval is then:

$$\Delta t = \Delta t[1 \pm 2 \cdot u_{\mathrm{T}}(\Delta t)_{\%}]\ \mathrm{s} \tag{30}$$

EXAMPLE 2

For the standard lightning impulse voltage from example 1, time to half-value (T_2) of 56,7 µs is measured. The horizontal scale sensitivity and record length were 10,0 µs/div and RL=2500 respectively. Uncertainty of time interval measurement ($\Delta t = T_2$) should be estimated.

Absolute error limit (in seconds) of time interval measurement by the oscilloscope is according to (23):

$$\dot{G}(\Delta t) = \pm\left(15\ ppm\ x\ |reading| + \frac{0{,}3}{real\ time\ sample\ rate}\right) =$$

$$= \pm\left(15 \cdot 10^{-6}\ x\ |56{,}7 \cdot 10^{-6}| + \frac{0{,}3 \cdot 100 \cdot 10^{-6}}{2500}\right) = 1{,}285 \cdot 10^{-8}\ \mathrm{s}$$

The absolute standard uncertainty (in seconds) is (24):

$$\dot{u}(\Delta t) = \frac{\dot{G}(\Delta t)}{\sqrt{3}} = \frac{0{,}01285\ \mu\mathrm{s}}{\sqrt{3}} = 0{,}007419\ \mu\mathrm{s}$$

and the percentage standard uncertainty of time interval measurement by the oscilloscope is (25):

$$u(\Delta t)_{\%} = \frac{\dot{u}(\Delta t)}{\Delta t} 100\ \% = \frac{0{,}007419}{56{,}7} 100\ \% = 0{,}01308\ \%$$

The total (overall) uncertainty of time interval measurement is estimated by the expression (29):

$$u_{\mathrm{T}}(\Delta t)_{\%} = \sqrt{u_{\mathrm{T}}(\Delta t)_{\%}^2 + 2 \cdot u_{\%soft}^2} = \sqrt{0{,}01308^2 + 2 \cdot 1{,}2^2} = 1{,}697\ \%$$

The complete measurement result of time to half-value (T_2) is according to (30):

$$T_2 = 56{,}7[1 \pm 3{,}4\ \%]$$

VIII. NEW PROCEDURE FOR LOW VOLTAGE LI MEASUREMENT

The uncertainties analyzed in previous sections are in accordance with the old (standard) procedure of low voltage LI measurements. In this procedure, the applied voltage, V_o, is measured by one measuring channel and the response voltages, V_i, are simultaneously (synchronously) measured on the remaining channels.

Given that the estimated expanded measurement uncertainty of the voltage ratio is quite large, we changed the measurement procedure. In the new procedure, the applied voltage, V_o, is adjusted and then measured by all available measuring channels. In the second step (and subsequent steps) only the response voltages, V_i, are measured by available measuring channels. It means that the applied voltage and response voltage are measured by the same measuring channel, but not simultaneously. As the applied and response voltages are measured by the same channel, they are in a functional relationship, or, more precisely, voltages are correlated due to the instability of the recurrent surge generator, the channels instability, resolution and nonlinearity of the measuring channels, and random deviations (interferences).

The measuring channels need not be calibrated, since both voltages (applied and response) are measured on the same measuring scale.

In order to verify the assumptions, it was first necessary to experimentally verify that the recurrent surge generator and the measuring channels are sufficiently stable within a given period of time, i.e. it was necessary to estimate (measure) the repeatability of the measurements over a period of 48 hours. The results are listed in Table II.

Table II. shows that the measuring channels measure the same voltage differently (error limits), but the standard deviations for each measuring channel are much smaller (due to stability of the generator and measuring channels).

Nonlinearity is the next influencing factor that needs to be checked and for which the component of measurement uncertainty has to be estimated. The usual range of measured response voltages is 15% to 100%, and the applied voltage is typically 300 V. In order to check the nonlinearity of the generator and the measuring channels, we adjusted the surge generator voltage to 50 V, 100 V, 150 V, 200 V, 250 V and 300 V and measured it simultaneously with the HIGHVOLT HiRES digital transient recorder (as reference) and the measuring channels of our measuring system (oscilloscope). All measurements were repeated 10 times and the measurement uncertainties were estimated according to [1]. The results are shown in Table III.

$\bar{F}_{1,i}$ is the mean of 10 repeated measurements (j; $j_{\max}=n=10$) of the scale factor (V_{HiRES}/V_1) of channel 1 at the „i“ voltage level (i; $i_{\max}=m=6$) and $u_{1,i}$ is the relative standard deviation of the mean value.

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$$\bar{F}_{1,i} = \frac{1}{n}\sum_{j=1}^{n}\left(\frac{V_{\mathrm{HiRES}}}{V_{1;j}}\right) \tag{31}$$

$$u_{1,i} = \frac{1}{\bar{F}_{1,i}}\sqrt{\frac{1}{n\cdot(n-1)}\sum_{j=1}^{n}\left(F_{1,i;j} - \bar{F}_{1,i}\right)^2} \tag{32}$$

F is the mean of the scale factor across all voltage levels (i, $i_{\max}$=m=6):

$$F = \frac{1}{m}\sum_{i=1}^{m}\bar{F}_{1,i} \tag{33}$$

$u_{1,BO}$ is the relative standard uncertainty due to nonlinearity for channel 1:

$$u_{1,BO} = \frac{1}{\sqrt{3}}\max_{i=1}^{m}\left|\frac{\bar{F}_{1,i}}{F} - 1\right| \tag{34}$$

The same applies to the remaining measuring channels.

Relative standard uncertainty due to nonlinearity for all four channels, u_F, is calculated as pooled standard deviation:

$$u_F = \sqrt{\frac{\sum_{k=1}^{4}(m_k-1)u_{k,BO}^2}{\sum_{k=1}^{4}(m_k-1)}} = \frac{1}{2}\sqrt{\sum_{k=1}^{4}u_{k,BO}^2} \tag{35}$$

(because it is $m_1 = m_2 = m_3 = m_4 = m_5 = m_6$).

TABLE II. EXPERIMENTAL CHECK OF STABILITY OF THE RECURRENT SURGE GENERATOR AND THE MEASURING CHANNELS

Parameters	Measuring channels	Mean	Standard deviation	No. of measurements
V_0	1	302,52 V	0,06725 %	51
	2	300,76 V	0,1067 %	51
	3	301,73 V	0,05860 %	51
	4	301,27 V	0,1103 %	51
β	1	-0,24012 %	0,04652 %	51
	2	-0,24778 %	0,04967 %	51
	3	-0,21083 %	0,04427 %	51
	4	-0,18255 %	0,04516 %	51
T_1	1	1,1765 µs	0,001317 µs	51
	2	1,1779 µs	0,001326 µs	51
	3	1,1754 µs	0,001169 µs	51
	4	1,1733 µs	0,001564 µs	51
T_2	1	53,694 µs	0,08925 µs	51
	2	53,989 µs	0,08512 µs	51
	3	53,836 µs	0,09009 µs	51
	4	53,824 µs	0,08270 µs	51

TABLE III. EXPERIMENTAL CHECK OF THE NONLINEARITY OF THE RECURRENT SURGE GENERATOR AND MEASURING CHANNELS

V_0	Channel 1		Channel 2		Channel 3		Channel 4	
	$\bar{F}_1$	u_1	$\bar{F}_2$	u_2	$\bar{F}_3$	u_3	$\bar{F}_4$	u_4
300 V	0,99924	0,00025	0,99676	0,00024	1,0063	0,00027	0,99781	0,00025
250 V	0,99994	0,00016	0,99792	0,00011	1,0073	0,00019	0,99895	0,00018
200 V	1,0011	0,00033	0,99853	0,00036	1,0078	0,00028	0,99938	0,00033
150 V	0,99965	0,00018	0,99785	0,00014	1,0063	0,00015	0,99831	0,00016
100 V	1,0048	0,00026	1,0033	0,00028	1,0125	0,00025	1,0040	0,00019
50 V	1,0143	0,00033	1,0102	0,00031	1,0214	0,00032	1,0132	0,00032
F	1,0032		1,0008		1,0103		1,0019	
u_{B0}	0,0064		0,0054		0,0063		0,0065	
u_F	**0,0062**							

The measured relative standard uncertainty due to the nonlinearity of all channels is negligibly small. However, when estimating the total (overall) measurement uncertainty of voltage ratio, standard uncertainty of calibration of HiRES transient recorder should be taken into account (0.32% according to transient recorder calibration certificate).

It is reasonable to change the sensitivity of measuring channel (V/div) to achieve higher resolution when measuring lower response voltages. Therefore, it was necessary to examine how changing the range (sensitivity) of the measuring channel affects the repeatability of voltage ratio measurement. For this purpose, a relatively low voltage of approximately 60 V is measured by measuring channels with a sensitivity change: 10 V/div, 20 V/div, and 50 V/div. The measurements were repeated 10 times and the results are presented in Table IV.

TABLE IV. INFLUENCE OF MEASURING CHANNEL SENSITIVITY ON MEASUREMENT REPEATABILITY

Sensitivity	Channel 1		Channel 2		Channel 3		Channel 4	
	$\bar{V}_1$/V	sd_1/%	$\bar{V}_2$/V	sd_2/%	$\bar{V}_3$/V	sd_3/%	$\bar{V}_4$/V	sd_4/%
10 V/div	60,292	0,020	59,965	0,020	60,159	0,020	59,929	0,028
20 V/div	60,362	0,10	59,943	0,073	60,194	0,070	59,995	0,059
50 V/div	60,592	0,12	60,035	0,12	60,421	0,132	60,178	0,10
$\bar{\bar{V}}$/V	60,415		59,981		60,258		60,034	
sd/%	0,26		0,080		0,24		0,21	
r	3		3		3		3	
sd_{pool}/%	**0,21**							

The relative standard uncertainty due to change in vertical scale sensitivity for all four channels, sd_{pool}/%, is calculated as the pooled standard deviation (35).

IX. MEASUREMENT UNCERTAINTY WITH NEW PROCEDURE

The analysis made in previous chapters confirmed the assumption that new procedure gives less measurement uncertainty of voltage ratio. Time intervals are measured with the same uncertainty as with the old procedure.

Since both voltages (applied voltage and response voltage) are measured by the same measuring channel, the total (overall) uncertainty of voltage ratio measured by the new procedure is reduced to the components of the stability of generator and measuring channel u_{st}, nonlinearity of the measuring channel u_{nl}, the change of sensitivity of measuring channel u_{se} and component of software uncertainty u_{soft}:

$$\dot{u}_{\mathrm{T}}(v_{\%i}) = \sqrt{u_{\%st}^2 + u_{\%nl}^2 + u_{\%se}^2 + 2 \cdot u_{\%soft}^2} \tag{36}$$

The first three components are characteristic of the measuring system in use. Based on the measurements made, the overall measurement uncertainty for our measuring system is:

$$\dot{u}_{\mathrm{T}}(v_{\%i}) = \sqrt{0{,}11^2 + 0{,}32^2 + 0{,}21^2 + 2 \cdot 0{,}058^2} = 0{,}4066\ \%$$

With the new measurement procedure, the total (overall) uncertainty of response voltage expressed in percentage of the applied voltage is 0,4066 %, which is about half the uncertainty when using the old procedure.

Complete measurement result of voltage ratio when using the new procedure for example 1 is:

$$v_{\%i} = v_{\%i} \pm 2 \cdot \dot{u}_{\mathrm{T}}(v_{\%i}) = \frac{46{,}66}{300{,}3} 100\ \% \pm 2 \cdot 0{,}4066\ \% = \{15{,}54 \pm 0{,}81\}\ \%$$

Complete measurement result of time interval is estimated in the same way as in the old procedure (see Examle 2).

The measurement uncertainty estimates of the new procedure are verified by extensive repetition of the measurements (r=51) extended to two days. The results are shown in Table V.

It can be seen that the standard uncertainty of repeatability for all repeated measurements at all levels of the selected voltage ratios is much smaller than the estimated overall measurement uncertainty according to (36).

TABLE V. EXPERIMENTAL CHECK OF NEW PROCEDURE SUITABILITY BY REPEATING THE MEASUREMENT (r = 51) AT DIFFERENT VOLTAGE LEVELS

	Channel 1		Channel 2		Channel 3		Channel 4	
	$\bar{X}_1$	u_1/%	$\bar{X}_2$	u_2/%	$\bar{X}_3$	u_3/%	$\bar{X}_4$	u_4/%
$\boldsymbol{V_0}$ /V	302,52	0,06725	300,76	0,1067	301,73	0,05860	301,27	0,1104
$\boldsymbol{V_1}$ /V	276,13	0,08413	274,60	0,1061	275,33	0,07241	274,88	0,1080
$\left(\frac{\boldsymbol{V_1}}{\boldsymbol{V_0}}\right)$ /%	91,277	0,09773	91,303	0,09435	91,251	0,08033	91,241	0,08862
$\boldsymbol{\beta}$ /%	-0,24012	0,04652	-0,24778	0,04967	-0,21083	0,04427	-0,18255	0,04516
$\boldsymbol{T_1}$/μs	1,1765	0,001317	1,1779	0,001326	1,1754	0,001169	1,1733	0,001564
$\boldsymbol{T_2}$/μs	53,694	0,08925	53,989	0,08512	53,836	0,09009	53,824	0,08270
	Channel 1		Channel 2		Channel 3		Channel 4	
	$\bar{X}_1$	u_1/%	$\bar{X}_2$	u_2/%	$\bar{X}_3$	u_3/%	$\bar{X}_4$	u_4/%
$\boldsymbol{V_0}$ /V	302,34	0,09113	300,77	0,08319	301,66	0,07919	301,17	0,08576
$\boldsymbol{V_1}$ /V	199,10	0,1778	198,03	0,1623	198,66	0,1542	198,33	0,1654
$\left(\frac{\boldsymbol{V_1}}{\boldsymbol{V_0}}\right)$ /%	65,853	0,1157	65,841	0,1122	65,854	0,1161	65,854	0,1074
$\boldsymbol{\beta}$ /%	-0,24818	0,06734	-0,24296	0,06141	-0,22620	0,06096	-0,19285	0,06422
$\boldsymbol{T_1}$/μs	1,1733	0,002324	1,1751	0,002402	1,1723	0,002123	1,1704	0,002314
$\boldsymbol{T_2}$/μs	53,817	0,1187	54,059	0,1034	53,889	0,1130	53,913	0,1132
	Channel 1		Channel 2		Channel 3		Channel 4	
	$\bar{X}_1$	u_1/%	$\bar{X}_2$	u_2/%	$\bar{X}_3$	u_3/%	$\bar{X}_4$	u_4/%
$\boldsymbol{V_0}$ /V	302,59	0,03461	300,69	0,03989	301,81	0,03655	301,11	0,03042
$\boldsymbol{V_1}$ /V	98,009	0,08405	97,378	0,07784	97,741	0,07949	97,519	0,08307
$\left(\frac{\boldsymbol{V_1}}{\boldsymbol{V_0}}\right)$ /%	32,391	0,03125	32,384	0,02796	32,385	0,02576	32,386	0,02780
$\boldsymbol{\beta}$ /%	-0,23447	0,02568	-0,24051	0,02874	-0,19131	0,03094	-0,17504	0,02652
$\boldsymbol{T_1}$/μs	1,1750	0,001056	1,1767	0,001134	1,1749	0,001027	1,1720	0,001194
$\boldsymbol{T_2}$/μs	53,746	0,02312	53,989	0,03036	53,807	0,02353	53,847	0,02209
	Channel 1		Channel 2		Channel 3		Channel 4	
	$\bar{X}_1$	u_1/%	$\bar{X}_2$	u_2/%	$\bar{X}_3$	u_3/%	$\bar{X}_4$	u_4/%
$\boldsymbol{V_0}$ /V	302,32	0,05412	300,32	0,06692	301,59	0,05606	300,79	0,06783
$\boldsymbol{V_1}$ /V	46,633	0,05415	46,392	0,07746	46,515	0,05742	46,356	0,06875
$\left(\frac{\boldsymbol{V_1}}{\boldsymbol{V_0}}\right)$ /%	15,425	0,01162	15,447	0,01233	15,423	0,01048	15,411	0,01109
$\boldsymbol{\beta}$ /%	-0,23862	0,03844	-0,24757	0,03530	-0,20571	0,03232	-0,18921	0,03624
$\boldsymbol{T_1}$/μs	1,1769	0,001342	1,1783	0,001309	1,1755	0,001118	1,1733	0,001286
$\boldsymbol{T_2}$/μs	53,672	0,04594	53,934	0,04574	53,800	0,05341	53,790	0,04503

X. CONCLUSION

Measurement uncertainty is a measure of the quality of a measurement result. Knowledge of measurement uncertainty is necessary for the acceptance of a measurement result and it is a basic parameter in the selection of measurement equipment and methods, as well as the basis for correct and reliable decisions.

By using measurement uncertainty analysis of LI voltage ratio, a better measurement procedure is developed.

The experimental check of the proposed new procedure shows that the amplitude (voltage) uncertainty has been reduced to half, with reducing the measurement time for about 15% when measured with 4-channel oscilloscope, or about 40% when measured with 2-channel oscilloscope.

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Overvoltages & Transients Identification In On-line Bushing Monitoring

Wieslaw Gil[1], Wiktor Masłowski[1], Przemysław Wronek[1]
[1]Mikronika sp. z o.o. Poznań, Poland
E-mail: wieslaw.gil@mikronika.com.pl

***Abstract*—Overvoltages and transients are sometimes recognized as the cause of bushings' rapid failure. This fact is confirmed by the studies published at the 2018 CIGRE session. They can also initiate dangerous resonance phenomena in transformer windings. The identification of very fast overvoltages characterized by high dynamics of voltage changes, so-called "transients", is difficult due to the limited frequency response of station voltage transformers. However, the bushing monitoring systems, based on the so-called "voltage method" can be used for this purpose successfully. There are several running bushing monitoring systems based on this method in Poland. The transients' events are registered together with their oscillographs in Transformer Monitoring Systems (TMS). The overvoltage statistics are also performed to support service procedures. The TMS are integrated with station systems, which greatly increases the possibility of overvoltages' phenomena analyzing.**

***Index Terms*—transients, overvoltages, on-line bushing monitoring, voltage method**

I. SWITCHING DISTURBANCES AND TRANSIENTS IN STATIONS' INFRASTRUCTURE

In 2015, CIGRE working group WG A2.37 published the brochure 642 [1], which presented statistics of overvoltages' and transients' impact on bushings installed in reactors and power transformers. The influence on bushing insulation of high-speed transients 1/50µs was also one of the topics discussed during the CIGRE session in Paris, in August 2018.

Overvoltages arising as a result of switching phenomena, lightings, groundings and other power failures in power lines affect the transformers' and reactors' bushings and winding insulation. The voltage values during such disturbances can reach voltage levels comparable to the test values for these devices.

During switching disturbances, very fast resonance waveforms featuring rise times even below 1 µs and multi thousand voltage changes are sometimes occurring. This undoubtedly causes partial discharges occurrence. They can also be the reason for particularly dangerous resonances in the transformer windings, which can lead to the winding insulation damage and internal short circuits [2]. Therefore, overvoltages can shorten bushing lifetime or even induce their rapid failures. They degrade insulation condition of a transformer or a reactor. Atmospheric lightings cause a different problem and their impact should be effectively limited by properly designed stations' lightning protection.

Therefore, it is necessary to monitor the fast overvoltages and transients occurrence in the power grid, assess their impact on the infrastructure condition and take remedial measures. However, identification of disturbances is problematic. The stations' voltage measuring transformers feature a limited frequency response, typically up to 50 harmonics. It is sometimes possible to transfer a signal up to 10kHz, but it is not enough for transients.

Identification and recording of fast overvoltage disturbances like transients, set a technical challenge. Input filters, measuring transducers and parameterized recorders triggers must be adapted to identify and record fast disturbances.

The data connected with network disturbances have a high economic significance. It can be used to improve the asset management but also to provide relevant information in resolving warranty or other disputes. Therefore, data protection and establishing the secure access rules to the collected statistics in the TMS can set a big challenge.

Fast overvoltages and assessment of their impact on bushing durability and reliability are rising an increasing interest, supported by statistics of occurring failures. At several power stations of Polish Transmission Operator PSE S.A., on-line bushing monitoring modules were installed [3]. They are identifying and recording voltage disturbances, including fast transients, caused by station switching operations and those reaching these stations from external lines as well.

Such modules were also installed in TMS in newly launched power plants. They enable phenomena identification caused by disturbances in circuit breakers operation and assessment of their impact on the bushing condition.

The authors profusely thank the Employees of PSE S.A. and Operation of Power Plants. They shared waveforms & registrations presented in this work. It should also be noted, that the presented data is for reference only and do not relate to any specific equipment or time

II. VOLTAGE METHOD

The measuring principle of the mentioned systems is based on the so-called voltage method of on-line bushing monitoring [4]. The method has not been widely used due to difficulties with accurate measurement of phase angles of voltage vectors at the bushing measuring taps. This resulted in an inaccurate tgδ estimation. Recently, these problems have been overcome by taking into consideration momentary line voltage asymmetry and synchronizing the measurement time. The advantages of this method are also confirmed by the results of analyses considering the possibility of measuring the higher harmonics of line voltages in bushing monitoring systems [5]. The capacitive probes installed in the bushings' taps make the basic component of the measuring system, as shown in Fig. 1. The measuring principle of this probe is illustrated in Fig. 2

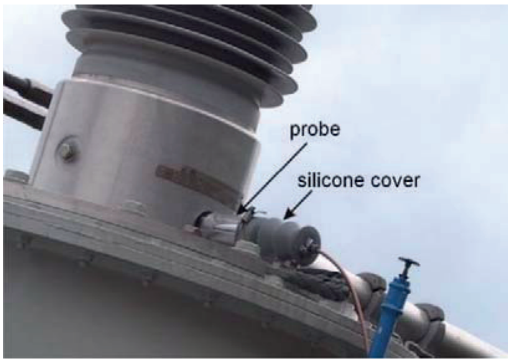


Figure 1: The probe installed in bushing measuring tap

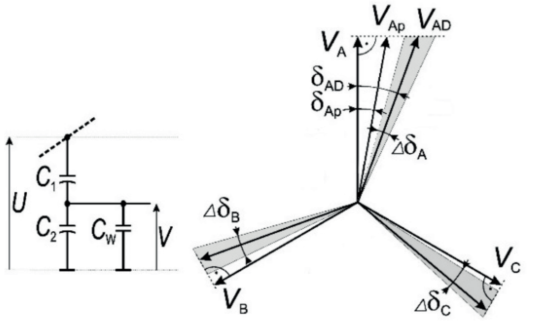


Figure 2: The capacitive probe operation principle and relative *tgδ* assessment

The C_w capacitor shown in Fig. 2 and the capacity C1 form a capacitive divider of the line voltage U supplied to the bushing. This capacitor is selected in connection with the voltage V at the measuring tap, which should amount to about 20 VAC. For example, the C_w = 800nF is selected for probes installed in 110kV bushings. The C_w capacitor, installed inside the probe together with overvoltage protection systems shall have a very good temperature stability.

Knowing the linear voltage module U, which is measured by the reference transducer and the capacitance C_w in the voltage module V, measured by the specialized converter, allows to assess the C1 capacitance. The tgδ assessment with the use of the relative voltage method is based on a precise measurement of the position and relative angle changes of individual phase voltage vectors. The current values of the angles are determined on this basis. It is assumed that in the phase in which phase angle changes have occurred, the dielectric properties of the bushing have also been changed. Then, the current tgδ coefficient is based on the new phase angle evaluation.

In the example shown in Fig. 2, the triangle of voltage vectors V_A, V_B, V_C, measured at the measuring taps of individual phases *A*, *B*, *C*, illustrates their initial position. Assuming, that a change had happened in the dielectric properties of the bushing phase *A*, then the V_A vector took a new V_{AD} position, which is determined by the angle δ_{AD}. The change of this angle was set in relation to the angle δ_{Ap}, resulting from the value of tgδ_{Ap} - measured after the installation of the TMS. The fluctuations $\Delta\delta_A$, $\Delta\delta_B$, $\Delta\delta_C$ of phase voltage vectors, caused by phase voltage asymmetry are also illustrated.

The voltage method, in addition to the C1 and tgδ factor assessment, allows the identification and recording of instantaneous values as well as RMS waveforms of overvoltages affecting the bushing. The V_A, V_B, V_C voltage vector modules are directly available in the measurement system, so they can be registered and archived in the bushing monitoring module along with other bushing parameters.

III. ON-LINE BUSHING MONITORING

The devices and structure of on-line bushing condition monitoring is presented in Fig. 3. Voltage signals from the measuring probes are connected to the Monitoring Module which performs required calculations and local data storage. The basic function of the installed equipment is to determine accurately the value of C1 capacitance and the value of the dielectric tgδ losses factor of the bushing in which the probe is installed.

For this purpose, the reference values of the measured relevant phase voltages from the Reference Unit are transmitted to the Monitoring Module by the IEC 61850 communication protocol. The work of both units is synchronized to GPS signal. The bushing capacity is determined with absolute uncertainty up to 1pF. The algorithm implemented in the Monitoring Module corrects the calculation errors resulting from a phase voltage asymmetry and estimates tgδ changes with absolute uncertainty 0.05%.

It is worth to comment, that the tgδ is an unnamed value in range 0,002 to 0,015 for not degraded high voltage bushings, depending on the manufacture technology. Traditionally, for convenience, it is expressed in arbitrary “percentage” units, after multiplying by 100. In this convention, the above typical values are from 0.2% to 1.5% respectively. The 'conventional percentage unit' has been used for many years in IEEE standards as well as in numerous articles. "Percent" values are also often used in bushings test reports. For this reason, it is justified to provide in this article an absolute uncertainty values, also in “percent”, discussing the quality of the tgδ coefficient measurements.

The principle presented in Fig. 3 is modified in power plants applications. The reference voltages U_A, U_B, U_C are connected directly to the Monitoring Module, where voltages from the bushing probes are also measured. This is possible due to relatively small distance of voltage transformers from the measuring system installation. Thanks to such solution, the equipment structure is simplified and the tgδ is determined with absolute uncertainty better than 0,05%.

Scaling of the measurements plays a very important role in the presented solution. It is performed after the equipment installation and the application of voltages. Then, the deviations resulting from the voltage vectors phase shifts in voltage transformers are compensated. The indication differences resulting from the C_2 capacitance influence and the C_w capacitors deviations from their nominal values are also trimmed automatically.

Station disturbances are characterized by high variability and dynamics. To trigger overvoltage recording, a threshold input with configurable hysteresis was implemented in wide measuring range. The change detection mechanism functions also in a parallel way. The voltage change is identified as a fast voltage disturbance when the programmable thresholds conditioning the triggering of the recording are exceeded or if the voltage change has the appropriate speed.

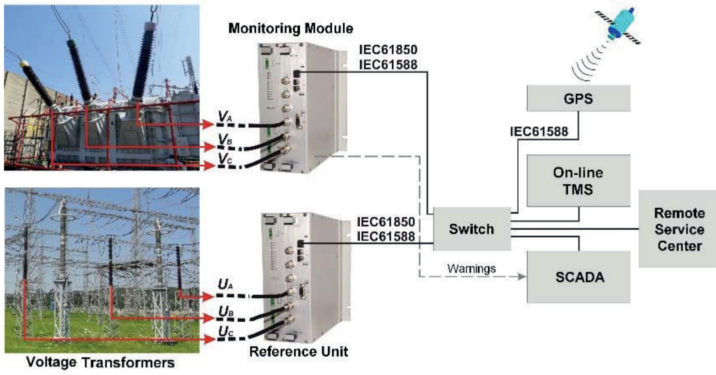


Figure 3: Structure of on-line bushing monitoring

TABLE I. RECORDER THRESHOLD FOR VARIOUS BUSHING NOMINAL VOLTAGES

Input signal & thresholds [kV]	Busihing nominal voltage [kV]		
	110	220	400
Signal range	280	560	1000
Detecting and recording threshold	140	279	488

Information about the surges along with information about the time of their occurrence is transmitted on-line to TMS as events with the transients oscillograph recordings and RMS waveforms in the COMTRADE standard files. Possible warnings and alarms created by TMS are directed to the SCADA station system. Expert access to the collected data in the monitoring server is possible from the Remote Service Center or through website secured mechanisms

IV. IDENTIFIED AND REGISTERED DISTURBANCES

Fig. 4 shows a recording example of a shortage disturbance that occurred on a 400kV line. A voltage peak exceeding 500kV triggered the recording after reaching the 488kV phase voltage. Subsequent oscillations and rapid voltage changes are placed on the first harmonic waveform.

Recently, bushing monitoring modules have been launched along with the identification and registration of overvoltage in newly built power plants in Poland. They give the opportunity to identify and thus eliminate the occurrence of dangerous phenomena, that may have a negative impact on the operation of block and reserve-start transformers. Fig. 5 shows an example of recording of switching overvoltage and resonance phenomena recorded on bushings when closing a 400kV circuit breaker during a put in operation.

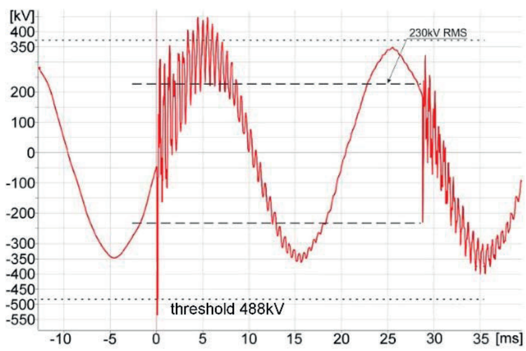


Figure 4: Shortage disturbance on 400kV line

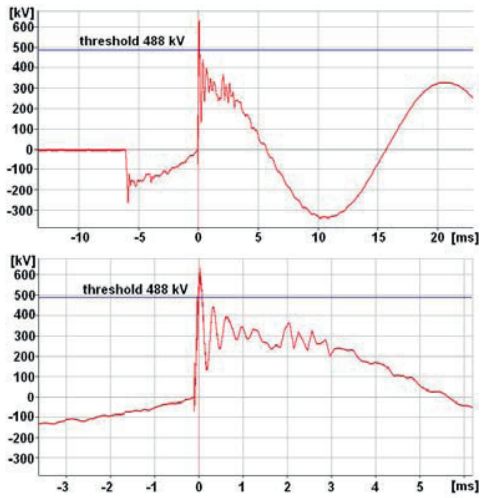


Figure 5: Switching overvoltage on 400kV line

Fig. 6 shows overvoltages caused by asynchronous switching of the 400kV line circuit breaker. A lightning discharge is probably a cause of the "transients" disturbances which are shown in Fig. 7. Nonlinear waveforms, visible in the initial phase in both above registrations, consist of many several hundred kilohertz oscillations. They significantly exceed the 500kV level and overlap the harmonic components. Oscillations of this type can generate partial discharges in bushings and transformer solid insulation. They are visible after enabling the "zoom" function in the program visualizing the recorded waveforms. A TMS analyzer of graphic images is used to observe and analyze these disturbances.

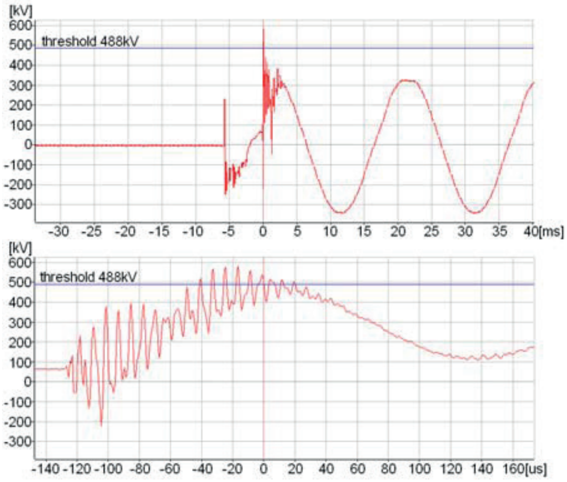


Figure 6: Asynchronous switching of the 400kV line

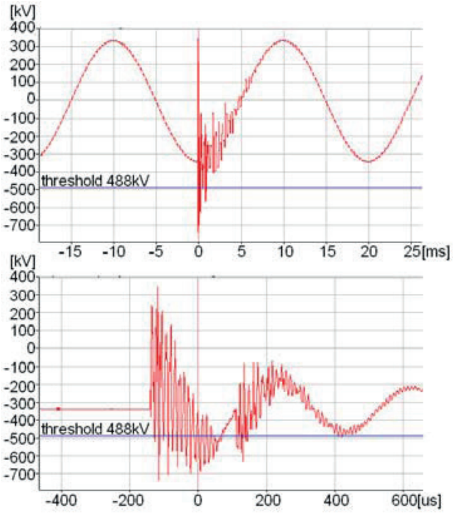
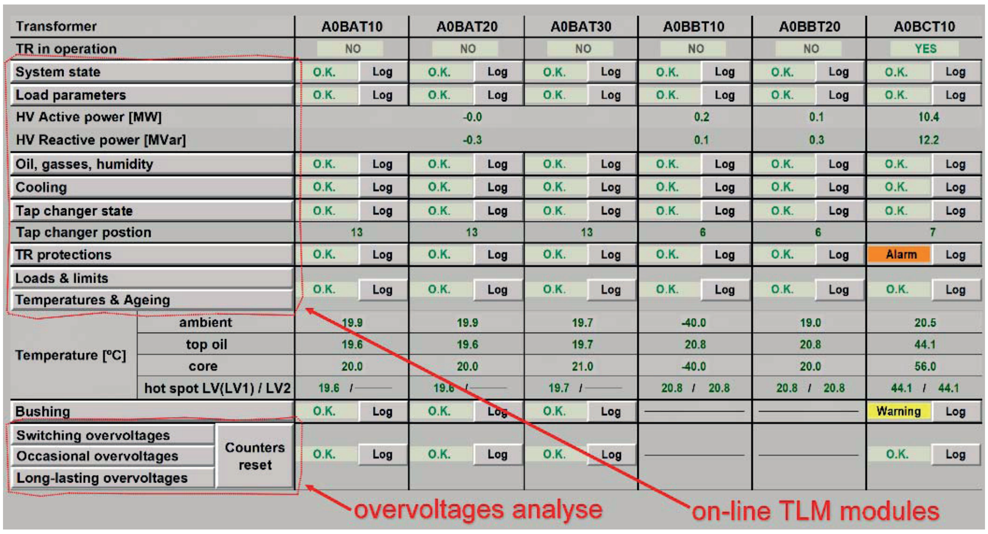


Figure 7: Transient overvoltage in 400kV line.

V. OVERVOLTAGE ANALYSES

The overvoltage identification and evaluation module should function as one of the TMS on-line modules. Such solution allows to correlate the collected statistical information about overvoltages and transients with other monitored parameters. It may be the data connected with partial discharges and related to the discharges gasses occurrence as well as rapid changes in capacitance C_1 of the bushing.

Fig. 8 shows the solution to this problem in the TMS of block transformers in the newly built power plant. The operation of the overvoltage analysis module can be verified on the main system screen. If necessary, individual overvoltage counters and waveforms can be analyzed and detailed reports can be performed. Any data analysis can also be obtained. The analysis can combine for example, recorded transients with data from the bushing monitoring module, as well as the moisture and gas in oil analyzer.



Transformer		A0BAT10	A0BAT20	A0BAT30	A0BBT10	A0BBT20	A0BCT10
TR in operation		NO	NO	NO	NO	NO	YES
System state		O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log
Load parameters		O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log
HV Active power [MW]			-0.0		0.2	0.1	10.4
HV Reactive power [MVar]			-0.3		0.1	0.3	12.2
Oil, gasses, humidity		O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log
Cooling		O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log
Tap changer state		O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log
Tap changer postion		13	13	13	6	6	7
TR protections		O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log	Alarm Log
Loads & limits Temperatures & Ageing		O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log	O.K. Log
Temperature [ºC]	ambient	19.9	19.9	19.7	-40.0	19.0	20.5
	top oil	19.6	19.6	19.7	20.8	20.8	44.1
	core	20.0	20.0	21.0	-40.0	20.0	56.0
	hot spot LV(LV1) / LV2	19.6 /	19.6 /	19.7 /	20.8 / 20.8	20.8 / 20.8	44.1 / 44.1
Bushing		O.K. Log	O.K. Log	O.K. Log			Warning Log
Switching overvoltages Occasional overvoltages Long-lasting overvoltages	Counters reset	O.K. Log	O.K. Log	O.K. Log			O.K. Log

Figure 8: Overvoltage analysis in TMS

Overvoltages evaluation is carried in the implemented systems out. There are several types selected, as shown in Fig. 8. When an overvoltage from a given range is identified, then the value of the corresponding counter is increased. Overvoltages exceeding the threshold level parameterized for the assumed power network are identified. A distinction is made between overvoltages of less than 50µs duration and overvoltages of 50µs to 200 ms duration - so-called switching overvoltages. Overvoltages with a duration between 200ms and 1sec and between 1 sec and 10 sec are classified as temporary. Overvoltages with a duration exceeding 10 seconds are included in the category of long-term overvoltages.

Fig. 9 shows a solution for transients monitoring used in bushing monitoring modules, implemented in newly built power plants. Overvoltages for power output transformers, i.e. BAT10, BAT20, BAT30, cooperating with generators and for the BCT self-needs autotransformer have been collected.

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https://doi.org/10.37798/202069340

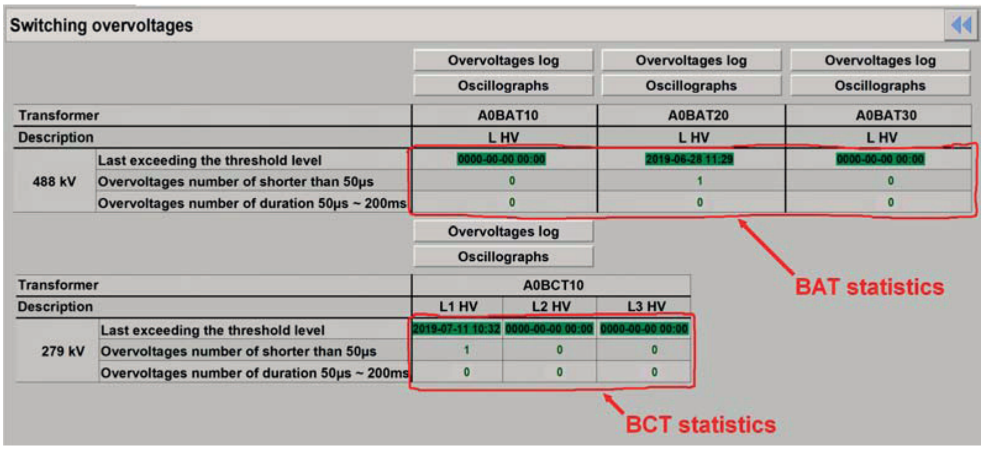

Figure 9: Switching overvoltage statistics

The system allows to create and analyze statistics of selected overvoltages, an overvoltage event log together with the time of occurrence of individual phenomena and individual disturbance oscillograms. The time of events such as exceeding the level of lightning protection, tgδ warning level, value of capacitance C_1 and other parameters are also recorded.

TMS with an installed overvoltage monitoring module can record and analyze overvoltages and transients on transformers and reactors which are caused not only by any switches at the station, but also those resulting from external disturbances. Therefore, overvoltage assessment should be able to determine the direction of disturbances. The implementation of an event registration mechanism for such disturbances gives the opportunity of system integration with other station systems, including the power quality assessment.

VI. CONCLUSIONS

Bushing on-line monitoring systems, based on the so-called voltage method, identify and record overvoltages, including transient overvoltages.

Identification, recording and analyses of overvoltages should form another functional module of the on-line TMS. It facilitates the performance of analyses and finding relationships between fast overvoltages and signals regarding, for instance, bushings, moisture & gas in oil analyzer and partial discharges.

The shape and level of recorded transient analysis can provide information on the status of lightning protection functioning at the station. Correlation of overvoltage events with changes in bushing insulation rates can provide valuable information in on-line bushing monitoring systems.

On-line bushing monitoring modules should collect statistical information regarding the type and size of overvoltages. Such information may support the decision about service performance, changes of operating conditions or the component replacement. However, access to this information is subject to special security protection and restrictions due to potential economic and legal significance. The above information may be crucial in the analyses of causes of failures and in the settlement of warranty disputes.

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Managing Transformers Risk through Failure Codification

Abdullah Mohammed Al Qabtan[1], Mohammed Said Dad Allah AlZadjali[1], Omran Omar AL Balushi[1]
Oman Electrical Transmission Company, Asset Performance Management Department,
Muscat, Oman P.O box 1389 Al Khoudh P.C 132
E-mail: abdullah.alqubtan@omangrid.com

***Abstract*— The fast development and expansion of any service organizations which followed by increases in the asset numbers that's need to have a proper maintenance strategy which should be cost effective. The aim of any strategy is to have a plan that contribute to improve asset performance by reducing downtime of asset failures.**

The aim of this paper is to set plan that determine the processes of creating failure code that can create a library of failure modes with its consequences and risk. This allow service provider to quickly understand the problem and any action that can be taken which have already proven by failure mode effect analysis. Also it's identify most of the functional failures that might happened in the critical asset in the OETC's network. In this study the transformer asset class was taken into the consideration for full failure mood and fault tree analysis.

Defining failure codes can give specific instructions to complete a task to reduce the main time to wait in any failure from the total main time to repair, and any smiler failure mode from other assets the corrective action will remain consistent.

The selective processes of creating a failure code give the organization a more holistic view of transformers risk which will be used to improve maintenance strategy by integrate those codes into work order system like CMMS.

***Index Terms*— OLCM: On line condition monitoring, OETC: Oman Electricity Transmission Company, CMMS: computerized Maintenance Management System, RCM: Reliability Centered Maintenance, RCA: Root Cause Analysis, FTA: Fault Tree Analysis**

I. INTRODUCTION

Asset Performance Management shall constantly endeavor to monitor and continuously improve the performance of the asset management system in order to ensure the effectiveness and efficiency of the transmission system in line with the Asset Management Objective. This process aims to provide a philosophy concerning the way to identify the source of failures and to change in working practices, values, relationships and culture in the company by focusing on how to manage failures rather than to select desired proactive tasks. Usually implemented when the systems fail to do what user want form the asset to do, but also aimed to improving the effectiveness of equipment by eliminating problems once and for all, by sustaining a level of asset care and good practice that prevent deterioration.

The process start up with a fault tree analysis (FTA). FTA is a logical diagram which shows the relation between system failure, and a specific undesirable events in the system as well as failures of the components of the system. The undesirable event constitutes the top event of the tree and the different component failures constitute the basic event of the tree where that must end with a desired outcome, and this needs to have a right process to manage the deliverables of proactive tasks.

II. FAILURE CODIFICATION APPROACH

With this emphasis on preserving what the RCA wants, Moubray [1] defines RCM as: "A process used to determine what must be done to ensure that any physical asset continues to do what its users want it to do in its present operating context." RCM approach considers seven questions as a starting point of the process.

1- What are the function and associated performance standards of asset in its present operating context?

2- In what ways does it fail to fulfil its functions?

The failure behavior of the selected assets should be identified by analyzing them under FTA approach that gives an overview of the subsystem failure contribution to the top event.

3- What causes each functional failure?

The common failure modes that may affect asset performance capability

4- What happen when each failure occur?

Understanding the effect of each failure modes will helps to evaluate the consequence of risk. This description identifying the level of severity and how could effect on the objectives of corporate business performance.

5- In what way does each failure matter?

The process focusing on managing the consequences of failure of each failure mode which is categorized as the followings:

- Hidden failure consequences: which has no direct impact to the operating crew under normal circumstances, but it may has serious/ catastrophic consequences, and most of those failure may happened in electrical system where, the deterioration of normal current are many and the source of problem are deferent as well.
- Safety and Environment Consequences: these are evident failures; the majority of this consequence can be defined on the risk assessment task, in order to know if this kind of risk can kill someone or breach any environmental regulations.

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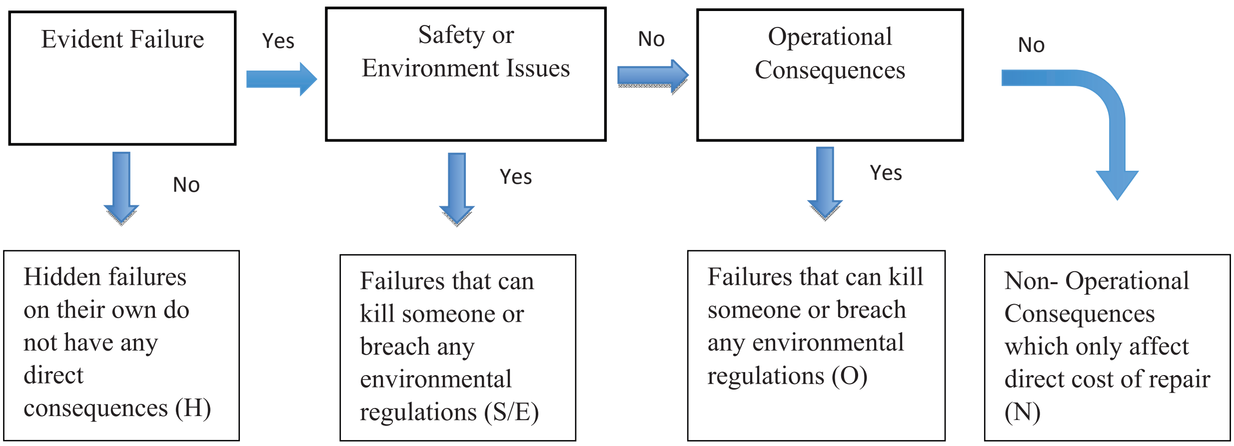
• Operational Consequences: these are evident failures; shutdown and blackout are the most critical time in the transmission line services, and the impact of blackout in long term can be reflected on the management quality of asset performance. These include lost production, increased operating costs, degradation in product quality, poor customer service, etc.
• Non- Operational Consequences: this kind of consequences caused by evident failure mode which has neither adversely effect on operation capability nor safety & environment, where their impacts on cost of repair only.

In so doing, those categories emphasize firstly on safety and environment issues, and then it focuses on how to manage failures rather than to select desired proactive tasks.
Process to Evaluate the Consequences of Failure:

Process to Evaluate the Consequences of Failure:



6. What can be done to predict or prevent each failure?
The Proactive Task Selection Process defined in Fig.1 below.

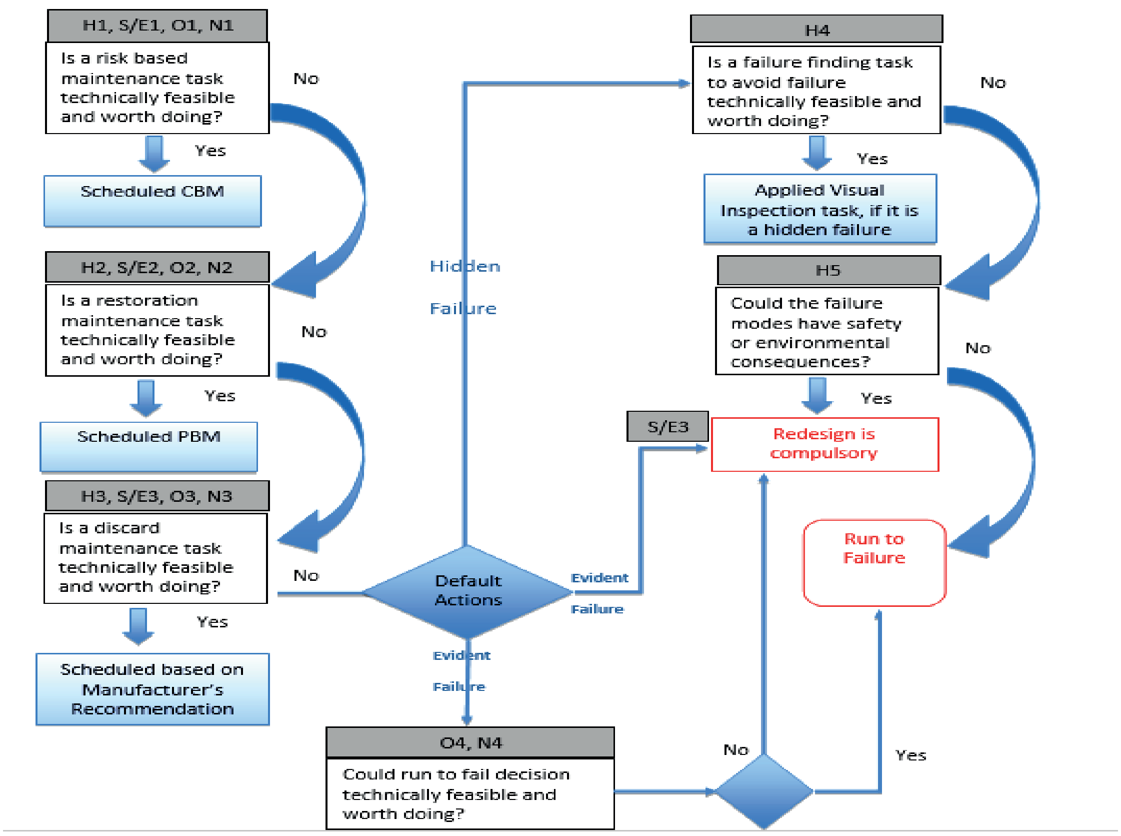


Figure 1: Proactive Task Selection Process

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7. What should be done if a suitable proactive task cannot be found?
Default tasks known as the tasks that includes run- to failure, failure finding and redesign. In other hand, the process advice to go through reactive tasks and that may eliminate the effects of failures once it occur.

III. TRANSFORMER FMEA

Power transformers in the transmission system are one of the main assets that can effect on the network reliability if they fail to do its operation. According to a described FTA of Transformer that is illustrated on the below diagram Fig. 2, each subsystem functions of the main asset class like transformer's oil should be identified clearly. Furthermore, transformer's oil plays as an insulation factor and it may fail due to water ingress, oil poor quality and oil contamination and also, the other purpose of transformer's oil is to maintain the dissipated heat into stabilized level, where its failure correlated with cooling system failures and due to deterioration of auxiliary's performance such as breathing system.

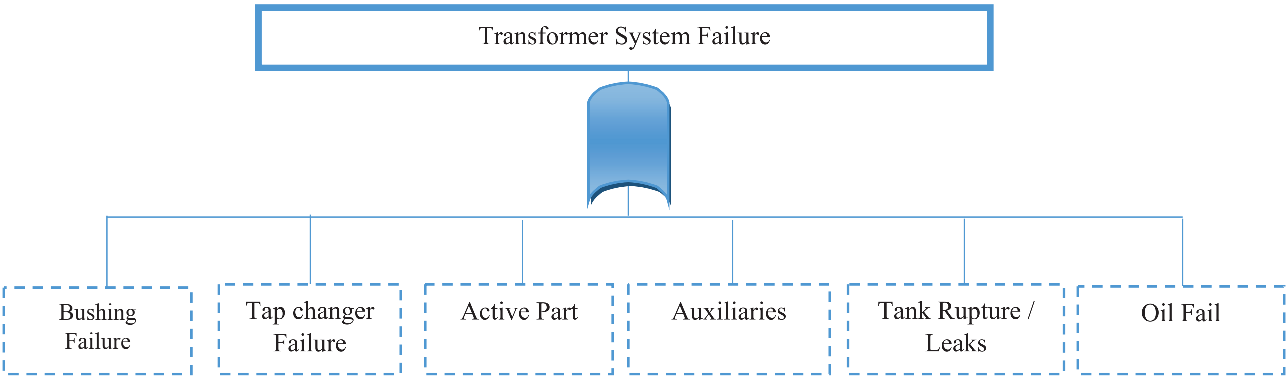

Figure 2: Transformer Fault Tree

According to above Fig. 2, each subsystem events should be analyzed throughout consequence evaluation in conjunction with the required proactive task that is shown in Fig. 1, and each number in Fig. 1 (1,2,3,4,5) refer to the maintenance category (CBM, PBM, …) that are linked with described consequence of that event. Furthermore, to create a failure code each subsystem will be considered as a separate function (F) and defined with a unique number, and its functional failures (FF) that are defined in FTA will take place as an alphabet later. Each functional failure has its own failure modes (FM) that again numbered with a unique number and all similar failure modes of different functional failures will be described with same number as they have same nature of failure but cause different failure. Table .1 below illustrate failure mode effect analyses of power transformer.

TABLE I. POWER TRANSFORMER (FMEA)

Function		**Function Failure**		**Failure Mode/Cause**	
1	Bushing	A	Bushing Structure	1	Gasket Fail
				2	Housing Fail
				3	Fitting Fail
		B	Conductor/Lead	4	Connection/Brazing
		C	Insulation Material	5	Paper Deterioration
				6	Lead Fail
				7	Oil contamination
				8	Aluminum foil Fail
				9	Test Tap
2	Tap changer	A	Drive Mechanism Fails	10	Motor Fails
				11	Gear Box and shaft Fails
				12	Limit Switch Fails
				13	Manual Operation Fail
				14	Power Supply Fail
		B	Tap Selection Switch	15	Contacts Wear
		C	Diverter Switch Fails	16	Contacts Failure
				17	Resistor fail

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		D	Tap Changer Oil	7	Oil Contamination
				18	Oil Level low
		E	OLTC Compartment	19	Bucholz Relay fail
				20	PRD Fail
				21	Fiber Glass Cylinder
3	Tank	A	Bucholz Relay fail	22	Float Fail
				23	Switch Disconnected
				24	Bucholz Valve Fail
		B	PRD Fail	25	Disk Fail
				26	Spring Fail
				23	Switch Disconnected
		C	Covers & Main Body	1	Gasket Fail
				27	Corrosion
				28	Lack of Maintenance
				80	Environmental Stress
				29	Physical Damage
4	Oil	A	Prticles in the Oil	30	Overheated
				31	Aging
		B	Poor Oil Quality	32	Poor Oil Quality
		C	Water Ingress	33	Oil Leak
				31	Aging
				34	Breather Fail
5	Auxiliary	A	Cooling System	35	Fan Fails
				36	Pump Fails
				37	Radiator Fails
		B	Breathing System	38	Supply Fail
				39	Silica gel Fail
				40	Heater Fail
				41	Oil Cap Fail
				42	Conservator Tank Fail
		C	Monitoring System	43	Sensors Fail
				44	Analyzer Equipment Fail
				45	Carrier Gas Cylinder Fail
6	ACTIVE PART	A	Winding	6	Lead Fail
				46	Insulation Paper (Celleulose)
		B	Core	47	Displacement of Core steel
				29	Physical Damage
				48	DC Magnetization

IV. MANAGEMENT RISK of TRANSFORMER FAILURE AND CREATING FAILURE CODE

The risk assessment framework defined within OETC based on the ratio between likelihood and consequences (critical analysis). Contribution of the subsystems failure to the major failure should be taken into account. Hence, risk assessment would be estimated according to asset management risk framework that covers expected load no longer meeting security standard, expected load interrupted, expected asset loading, safety, environmental and financial impact. The total score of the classified risk consequences that is shown in appendix- A will be escalated or deescalated according to the probability of failure (likelihood) which was identified from the past incidents and then simulated with corporate risk register to understand the impact of those failure on the whole business. This correlation gives asset management engineers the rational basis to decide the required solutions, and the right maintenance actions to be performed. Also, managing system failures against risk, will help to categorizing the required subsystem spares according to risk level, and to set a contingency plan of backup spares limitation by defining maximum backup spares from the minimum one within the inventory list. Therefore, failure codes could be vary according to the current risk situations which will help also the service provider to understand the nature of failure and the required action complete the work order and to close the incidents once it happened. Fig. 3 shows risk scoring practice within OETC and the total score will be converted into corporate risk level.

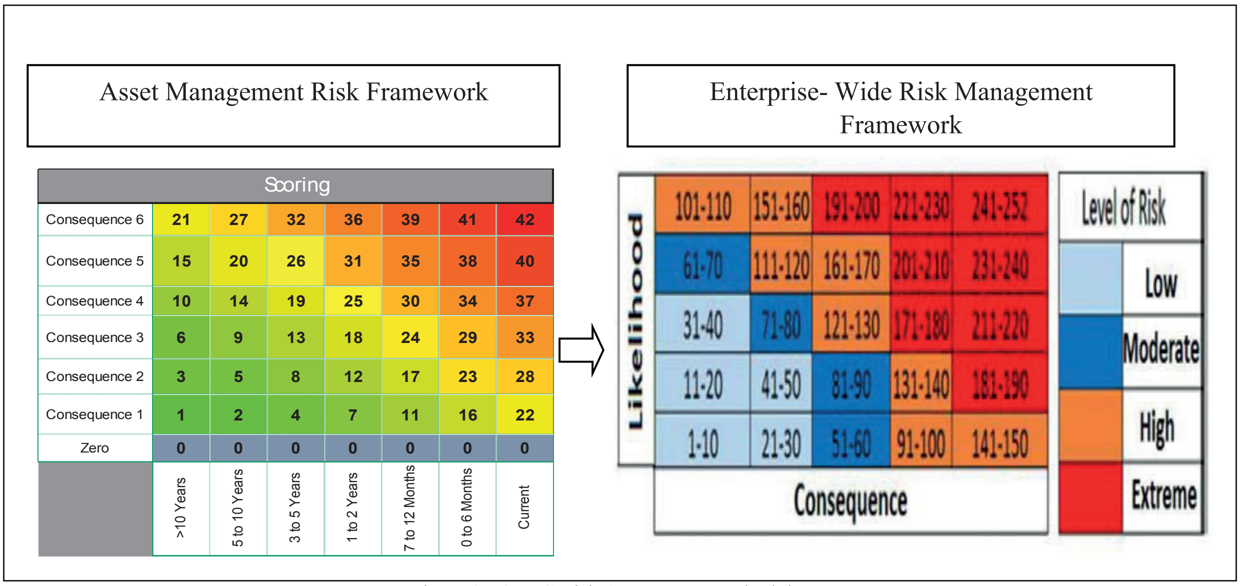

Figure 3: OETC Risk Assessment Methodology.

After defining transformer FMEA, each failure mode with the specific functional failure is linked with consequence code reference (H, S/E, O, N), and with suitable proactive task number then with the defined risk level for each failure. Therefore, the failure code of transformer (TX) bushing (Bu) failure is: **TX, Bu, 1A1, S/E1, Low** that defined in the Table II below.

TABLE II. POWER TRANSFORMER CODIFICATION METHODOLOGY

Equipment/Identifier		**FMEA Reference**			**Consequence Evaluation**	**Technical Feasibility Level**			**Default Task**		**Risk Level**
System	Subsystem	F	FF	FM		1	2	3	4	5	(Expected load no longer meeting security standard, expected load interrupted, expected asset loading, safety, environmental, financial impact) *Appendix- A
TX	Bu	1	A	1	S/E	☑					(2,5,5,14,2,5) = 33 **Low**

From Table I, table. II and according to RCM approach, fifty five kind of failure code have been created for the transformer failure. All the created transformer failure code have been started with TX, where TX was selected as a reference symbol of the transformer asset class.

Nonetheless, the study not conducted only to create a failure code, but also gives a hypothesis of failure behaviors in the network by analyzing each failure with its consequence and gives an overview of the risk level with desired maintenance plan, which create an approach of risk based maintenance strategy that focusing on selecting the right action upon the status of risk against cost under the point view of technically feasible and worth doing. It has been observed that the total transformer failure that could be monitored around 49 failures out of 55 failures and the remaining 6 failures, where 4 of them will be controlled under maintenance restoration task and the other 2 will be taken under default actions. Therefore the total detectable failure around 89.09% and the non-detectable failure around 10.91%. From another angle, according to risk evaluation for each failure, it has been noted that the total low risk around 76.36 %, while moderate risk level covers 21.82 % from the total risk and only 1.82 % considered as a high risk level. No extreme risk has been considered according to the records of risk management register. Consequently, the total debatable failure with risk level will be as the following: 37 failures as a low risk, 11 failures moderate risk and 1 failure as a high risk. From this standpoint, asset management launch a project to establish and implement a continuous On-Line Condition Monitoring (OLCM) system for OETC's network assets. It was found that the probabilistic tangible benefits are derived from the failure code model, where the failure rate of transformers is 0.5% [2] for average age of OETC transformers according to CIGRE Guide 248. According to the reliability centered maintenance recommendations which describe the desirable of condition monitoring implementation against other maintenance tasks, 89.09% of 0.5 % of probable failure can be detected by condition monitoring activities. Hence the probabilistic detectable failure rate by condition monitoring task is around 0.044. If the capital cost of power transformer of 750 MVA is considered about 1.5 million Omani Rials, than the total probabilistic detectable tangible benefits around 66,000 Omani Rials. Such studies could be implemented taken failure code model as a reference which could be vary from utility to the other, according to their experience and to the type of risk appetite.

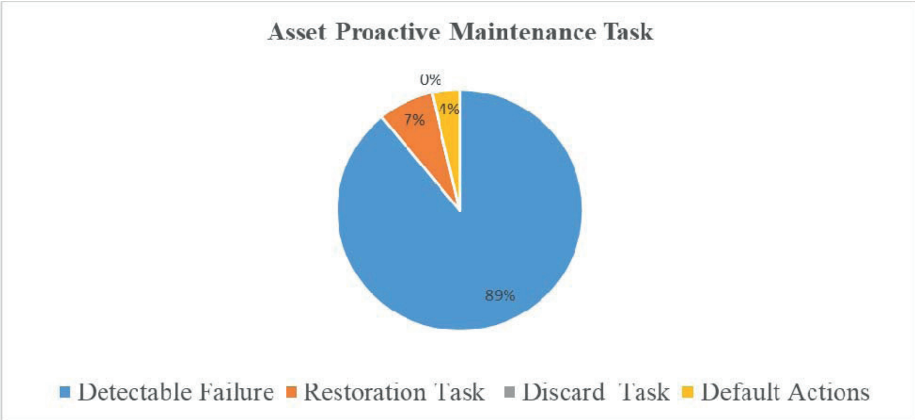

Figure 4: Transformer Proactive Task

V. FAILURE CODE SYSTEM MODEL AND CMMS INTEGRATION

Asset Management, introduced a failure codification management system, the codes installed on OETC servers and it provides full support that centralizing the information within the CMMS system. This vision needs many stages and tools that can be shortly defined as a Failure Codification Model that has a closed framework process to enhance risk management system and to provide modern analytic strategy. To cope with strategic model, failure code shall control the systematic approach in terms of incident data management, required maintenance over risk, performance system study, maintenance strategy and asset performance management.

The output and benefits of implementing failure codification model are addressed below:

- Centralize failure code within CMMS system
- Governance data management system
- Avoid discrepancy between failure and right proactive action
- Organizing the circulation of failure risk review process
- Secure and document incident register with failure code and then align it with risk status
- Adhere service provider engineer to follow the process of maintenance and failure codification review process
- Referencing failure code and asset sock over age profile
- Helps to analyze asset system failure.
- Enhanced regulatory compliance and reporting

In CMMS, failures codification is loaded in term of sets. Each set consist of failure code, cause code and resolution code. In other words, table I above is transformed into CMMS to create failure codifications. Moreover, table III below illustrates an example of failure codification.

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TABLE III. FAILURE CODES EXAMPLE IN CMMS

Failure		Cause		Resolution		Failure set	
Code	Description	Code	Description	Code	Description	Code	Description
F023	Bushing_Structure_1-A	C001	Gasket Fail-1	R008	Scheduled CBM-S/E1	Transformer_FC	Transformers Failure codes

Each failure code starts with "F" and three digit numbers indicating a unique failure code, similarly, cause codes starts with "C" and resolution codes starts with "R".

Failure codes of table I are programmed in CMMS in a systematic way, such that whenever an engineer chooses certain failure, system limits all causes to that failure. Correspondingly, it limits all resolutions based on the chosen cause of the failure.

Failure analysis section in CMMS supports engineers in following up historical failure data, modifying or adding new failure codes and it shows the hierarchy of all failure codes which displays the linkage of all failure, cause and resolution. Fig. 5 below shows failure analysis section in CMMS, where engineer can search for any previous failure stored in CMMS.

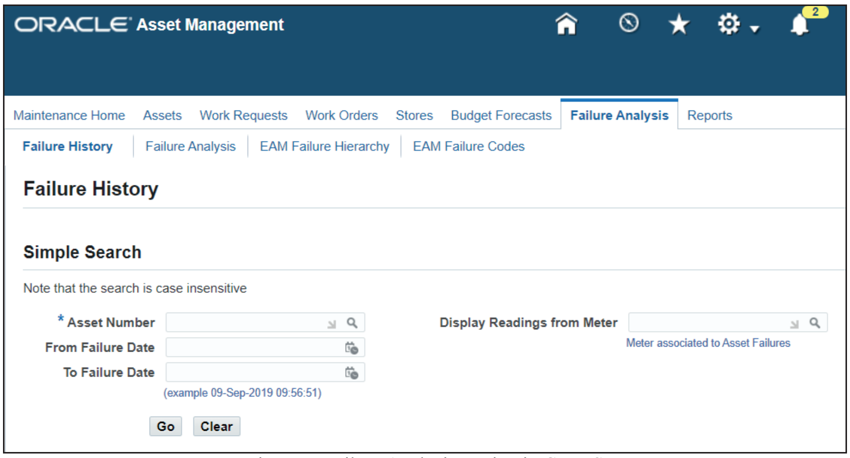

Figure 5: Failure Analysis section in CMMS

Failure sets gather all failures, causes and resolution in one code based on asset class, which make it easier for an engineer to record or search for a failure in certain asset group.

Another feature of failure codes in CMMS that it is linked with work orders. Any failure occurs while executing a work in the site can be recorded to that particular work order. Moreover, this linkage between failure codes and work orders will keep a historical record of all failures in each asset, which will supports the management in taking decisions.

VI. CONCLUSION

There is a need for raising the quality level of maintainability with improved RCM procedure and guidelines from failure code. With respect to the identified issues, the paper is recommends the followings:

- Review and improve the present maintenance against risk
- Create a unique failure code and that has to be utilized within company documentations
- Increase general awareness of the risk level and prepare proper mitigation / contingency plan

The proactive tasks from RCM have been designed to fit risk impacts under consideration of cost effective maintenance. Also, any maintenance program has to be scheduled to meet risk mitigation plan and to ensure the availability of spare parts when it's required. The importance of availability of spare parts is to maintain and to optimize spare parts inventory to support reliability and maintainability objectives. Strategic spare parts requirement has to be aligned with failure code to ensure best availability level and to meet security standard requirements.

OETC implement this concept on the other critical assets like: transformer, switchgear, protection system, overhead lines and underground cables. All critical assets have now a unique failure code that give the service provider a full picture of the failures and their mitigation actions. Also, this model document the failures with the proposed codes that are linked with risk management process which will be reviewed quarterly basis once there extreme and high risk.

VII. REFERENCES

[1] Moubray.J., 1992. Reliability Centered Maintenance. 2th. USA: Industrial Press Inc.
[2] Cigre Guid 248 Power Transformer Failure Rate change by age of unit.

APPENDIX A

Expected Load no Longer meeting Security Standard MWh **NS**

The expected amount of load (in MW) no longer meeting the required security standard for the duration of the asset restoration or implementation of the

72,000 MWh and Above							
33,600 MWh to 71,999 MWh							
16,800 to 33,599 MWh							
2,400 to 16,799 MWh							
800 to 2,399 MWh							
1 to 799 MWh							
No Impact							
	>10 Years	5 to 10 Years	3 to 5 Years	1 to 2 Years	7 to 12 Month	0 to 6 Months	Current

Expected Load Interrupted MWh **NS**

The expected amount of load (in MW) interrupted for the duration of the asset restoration or implementation of the mitigating action (in hours)

2,400 MWh and Above							
1,800 to 2,399 MWh							
1,200 to 1,799 MWh							
600 to 1,199 MWh							
200 to 599 MWh							
1 to 199 MWh							
No Impact							
	>10 Years	5 to 10 Years	3 to 5 Years	1 to 2 Years	7 to 12 Month	0 to 6 Months	Current

Expected Asset Loading % **NS**

Expected loading of related assets resulting from asset event, load growth or lack of investment

> 120%							
> 115% <= 120%							
> 110% <= 115%							
> 105% <= 110%							
> 100% <= 110%							
> 80% <= 100%							
<= 80%							
	>10 Years	5 to 10 Years	3 to 5 Years	1 to 2 Years	7 to 12 Month	0 to 6 Months	Current

Safety Scale **NS**

Expected safety impact resulting from asset event

· Multiple fatalities where a Company or an Officer from the Company may be held liable.							
· Single fatality and/or multiple injuries at resulting in irreversible impairment/inability to work							
· Injury or impairment** to one or more persons resulting in person admitted to hospital or reportable to regulatory body or restricted duties or lost time							
· Injury requiring medical attention and follow up treatment							
· Injury requiring medical attention but no follow up treatment required							
Near Miss							
No Impact							
	>10 Years	5 to 10 Years	3 to 5 Years	1 to 2 Years	7 to 12 Months	0 to 6 Months	Current

Environmental Impact lts or kg **NS**

Expected environmental impact resulting from asset event

56,000 Litres of Oil or 200 kg SF6 or Above							
18,000 to 55,000 Litres of Oil or 150 to 199.9 kg SF6							
9,000 to 17,999 Litres of Oil or 100 to 149.9 kg SF6							
4,500 to 8,999 Litres of Oil or 50 to 99.9 kg SF6							
2,000 to 4,499 Litres of Oil or 5 to 49.9 kg SF6							
Up to 1,999 Litres of Oil or 4.9 kg SF6							
No Impact							
	>10 Years	5 to 10 Years	3 to 5 Years	1 to 2 Years	7 to 12 Months	0 to 6 Months	Current

Finance OMR **NS**

Expected direct financial impact resulting from asset event (excluding lost revenue)

250,000 OMR or Above							
100,000 to 249,999 OMR							
50,000 to 99,999 OMR							
25,000 to 49,999 OMR							
10,000 to 24,999 OMR							
1 to 9,999 OMR							
No Impact							
	>10 Years	5 to 10 Years	3 to 5 Years	1 to 2 Years	7 to 12 Months	0 to 6 Months	Current

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Advantage of in Service Condition Based Assessment for Transformers in enhancing the maintenance strategy

Ibrahim Al Balushi[1]

[1]Oman Electricity Transmission Company, Muscat, Sultanate of Oman

E-mail:Ibrahim.albalushi@omangrid.com

Abstract*—controlling the maintenance OPEX is one of the major challenges that any utility faces. The challenges lie in how to optimize the three main factors: risk, performance, and cost. Besides, no utility can depend on a unique type of maintenance, there is always a combination of a different kind of maintenance such as breakdown, preventive, risk-based, condition-based,..etc. So, what is the answer to this question: what type of maintenance needs to be followed to keep the transformer in service in with high performance? There is no specific answer to this question. Each type of maintenance can be applied based on the transformer`s operating environment. However, most of the utilities apply preventive and condition-based maintenance. To justify this answer, some data need to be analyzed to assess the maintenance performance and recommend what are enhancement need to be added. One of these approaches is to apply in service condition-based assessment to study the health of the assets based on the current maintenance practice. Furthermore, study both historical maintenance records and failure rates will help to understand the relationship between the effectiveness of maintenance and service efficiency. This relation can come in two shapes. One is to do the right things by developing a set of maintenance activities that need to be performed during the maintenance to ensure its effectiveness. Second, is to do things right by enhancing the maintenance crew capabilities and competencies to ensure high efficiency. After analyzing all these factors mentioned above, It has been noticed that in-service condition-based assessment of the transformer is a powerful tool that can be used to enhance and build an effective strategy. It will not only involve a set of activities during the maintenance, but it also covers the whole life cycle of the transformer. Besides, it highlights the gaps in the maintenance process and procedures, and provide indications where enhancement need to be applied based on international practice. These changes were observed on the cost and performance in the benchmarking study that was done through International Transmission Operation and Maintenance Study (ITOMS) which was a good indication of the effectiveness of strategy used for transformers. However, as part of the asset management approach, continuous improvement will continue to reach the vision that has been set in the maintenance optimization and to prepare for the future significant increase in transformer aging.

I. INTRODUCTION

Asset Management is the science, and art of optimal allocation of resources in the pursuit of achieving given objectives. These objectives may include meeting threshold criteria related to reliability, performance, costs, and prevailing legal mandates. Simply put, the question boils down to, "Where do I invest to achieve the desired objectives, subject to various constraints?" From the Utility's perspective, Asset Management comprises the entire life cycle – cradle to grave – of equipment. Asset Management typically begins with the process of planning and continues through procurement, installation, commissioning, ongoing operation & maintenance, and salvage. While the first step – planning – addresses the capital allocation issue, the last step – salvaging – lays the foundation for the next round of planning, and capital allocation, thus perpetuating the continuous cycle of Asset Management. Although there were no major transformers failures and it shows a high service performance during the past years, the participation in the international benchmarking showed that transformer OPEX is higher than most of the international transmission utility participating in the study. Besides, increase in the number of the transformer evoked some questions such as how many resources are needed to face these numbers of transformer, how instance can be covered based on the current maintenance practice, are the company willing to accept these increase in the OPEX especially what the decrease in the oil price and the desire from the shareholders to decrease the OPEX. Although the vision was clear, there were many challenges were faced. Any changes in the current maintenance practice need to be supported with data analysis and develop risk assessments associated with these changes. Furthermore, the strategy shall focus on the effectiveness procedure shall concentrate on efficiency. Among several options, the decision was taken study the outcome of the in-service condition assessment that was performed in 2010 and 2015 along with the maintenance history and failure rate to develop a strategy that suite OETC system and monitor its effectiveness though continues the analysis of the reports.

II. HISTORICAL MAINTENANCE PRACTICE.

During 2008 and 2018, the population of the transformers has been increased dramatically by the minimums percentage increase of 8% and the maximum increase 26% annually. In 2008, the network consisted of both 132 and 220 kV whereas the 400 kV has been introduced in 2016. This rapid increase in the transformer investment met a major challenge in the maintenance according to the maintenance since 2008. As shown in both figures 1 and 2, the maintenance of every transformer consumes 8 hours on average. The previous maintenance practice involved some of the basic activities such as cleaning, measure the isolation resistance of the winding, operation test…etc. From 2008 to 2015 and due to the increase in the number of transformers, the maintenance crew faced challenges to treat all transformers in a limited duration from October to April. As shown in figure 3, the maintenance duration involves 1768 hours. It is noticed that the maintenance hours for 2017 and 2018 were higher than allowed hours. Although there is more than one maintenance team that can perform the maintenance, it is worth to mention that this maintenance period is for maintenance activities such as switchgear, axillary system..etc. Besides, the highest priority in this period was given for the projects. With these activities, it is essential to maintain system security, high reliability, and availability. Furthermore, the benchmarking study shows that OETC is spending high costs on the transformer maintenance as it will be shown later. This led to a decision from the management to reduce the cost of the maintenance and find an effective solution and plan to optimize the maintenance. Another factor was considered also as one of the challenges, the number of grid station investments has been increased since 2012. Besides their involvement `in the maintenance activities, site engineers are also involved in the commissioning and testing of new projects.

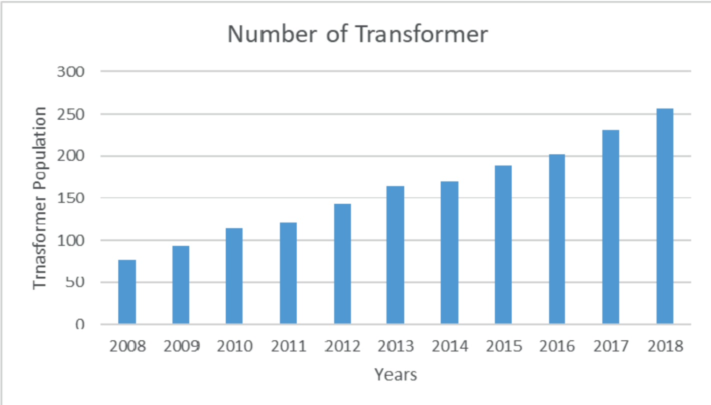

Figure 1: Transformer population 2008-2018

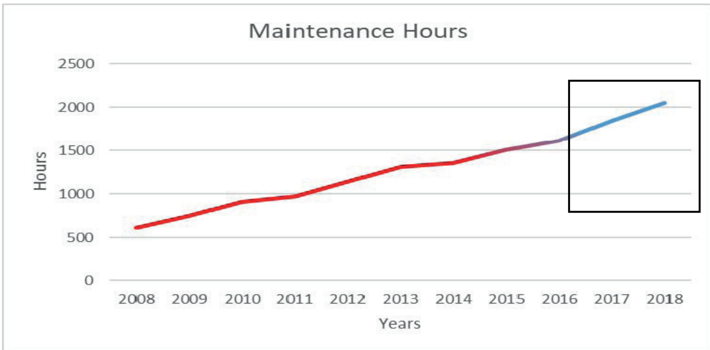

Figure 2: Time spent in the maintenance

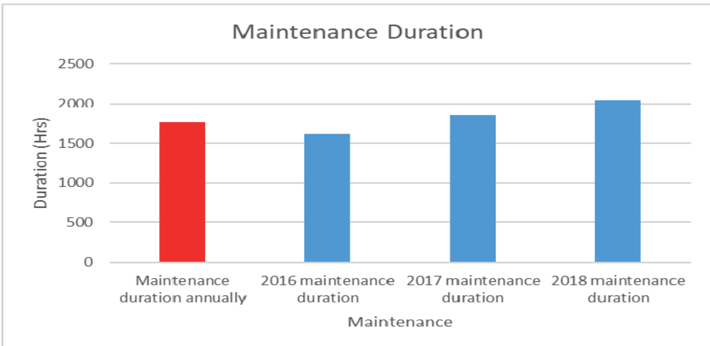

Figure 3: Expected maintenance duration for 2016,2017 & 2018

III. CONDITION ASSESSMENT.

To assess achieving the asset management objectives, condition assessment and site tests have been conducted for transformers in the network in both 2010 and 2015. This initiative was a new experience for OETC which was not be used in the past. The condition assessment involves partial discharge, thermal imaging, and visual inspection. Based on

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these factors, the transformer's condition will be categorized according to the maintenance requirements and fast response which will be represented in the form of risk. Despite the availability of the test reports and information from the time-based maintenance, the in-service condition assessment will provide the utility enough information about the status and the condition of its assets while they are under operation. These data can be used to build an asset health index, failure mode, develop an effective asset register, life cycle replacement. However, the main scope of the asset condition assessment will involve the following

- Collection and analysis of relevant (historical) data.
- Detailed Visual Inspection of the Grid Stations and individual assets.
- In service Partial Discharge testing of Transformers using UHF.
- Infrared Thermal Imaging of the Transformers
- Evaluation of test results, identify the weak points in system and suggestion of remedial measures through approved technical reports.
- Health Index ranking for all assets.

Once all data analysis is done, the asset will be ranked based on the criticality of each asset as mentioned in the table below:

Table 1 : risk classifications of the condition assessment findings.

Risk	Action
High	Immediate action
Moderate	Within 6-12 months
Low	Within 1-5 years
Normal	No action is required

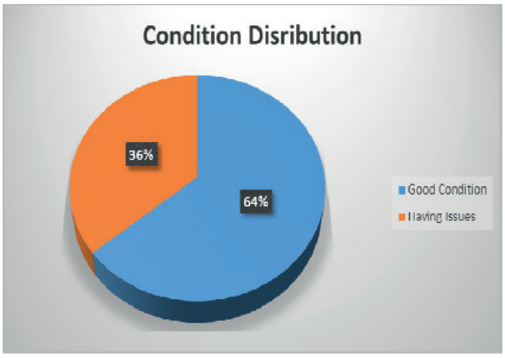

Figure 4: Transformers Condition Distribution in 2010 and 2015

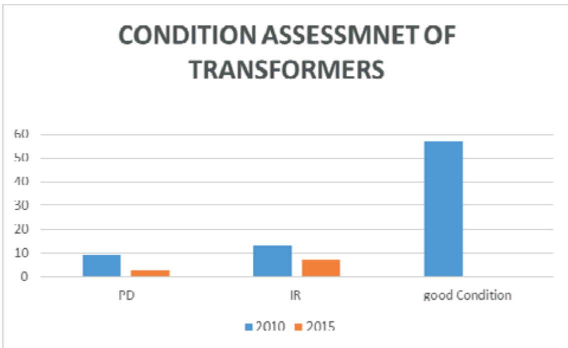

Figure 5: Type of Transformers Findings issues in 2010 and 2015

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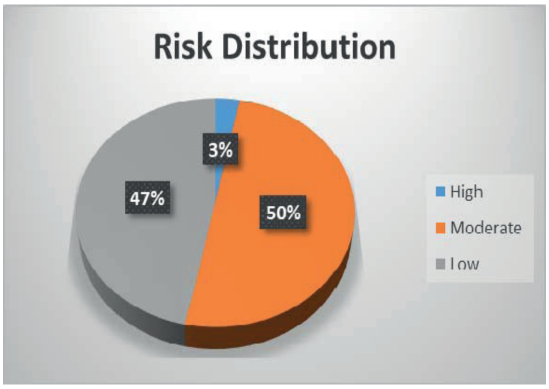

Figure 6: Transformers Risk Distribution 2010 and 2015

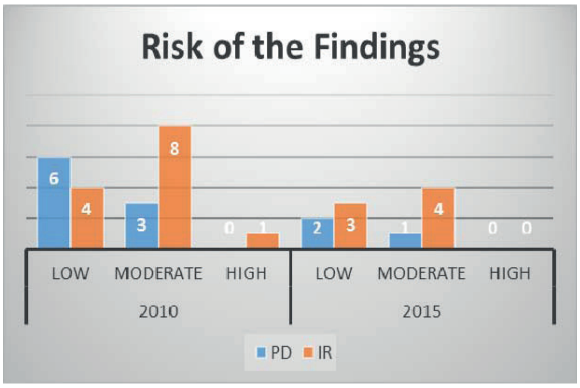

Figure 7: Risk Findings in 2010 and 2015

IV. DATA ANALYSIS.

Figures 4 & 5 illustrate the condition assessment of 89 transformers 2010 and 2015. Figure 4 shows the results of 57 transformers sustain good conditions in both years. This result represents 64% of the total transformers as shown in figure 5. The condition assessment of the Partial Discharge (PD) measurement resultant that there were 9 transformers had PD in 2010. On the other hand, these results encountered a sharp reduction in the number of PD findings in 2015 by around 75%. One of the main observations that had been noticed, none of the 12 transformers had a PD in both years. It can be also seen from figure 4, the results of Infrared (IR) thermography for 20 transformers who got some issues using this kind of test in both years. in 2010, 13 transformers got issues as a result of the IR. Similar to PD measurement, in 2015 there was a decrease in the number of issues found in the transformers compared with 2010 by around 50%. Unlike PD, four transformers got issues in both years using the IR test. Generally, among 89 transformers there were tested in both years, the condition assessment results showed that 32 transformers were found having some issues varied between PD and IR findings. this number represented 36% of the total tested transformer in both years as shown in figure 5. However, although the findings formed 36% of the total transformer, these findings have a different range in the risk classifications as shown in table 1. Both Figures 6 and 7 gave distributed condition assessment findings in terms of the risk classifications. 47% of the transformers have a low risk which means that this risk needs to be cleared within 1-5 years. in contrast, 50% of the transformers have a moderate risk. Whereas only 3% of the transformers lay within the high risk. Only 7 transformers at low risk using IR in both years. There were only a few observations found such as hotspots in one of the transformer parts and some of them related to radiator valves. Some of the valves were found closed which prevent the oil circulation. When the oil circulates, it helps in the transformer cooling by dissipating the heat while the oil circulation. The closing valve will contribute to increasing the heat in some of the parts of the transformer which will be detected by IR. Similarly, 12 transformers were considered to be at moderate risk using the IR test in both years. Most of the observations were related to the transformer oil. The majority of the 12 transformers have some thermal activities which they are not be considered as a moderate. Serval Dissolve gas analysis was conducted to monitor and confirm the condition of these transformers. The results showed that these transformers were subjected to high load and high temperatures during the summer period. As a result, temporary thermal activities occurred for a short period. It is noticeable the only high risk has occurred in 63 MVA transformer which was commission in 1995. It was observed during IR testing that high hotspots in the connection point of the transformer bushing with the conductor. There are two reasons to explain this issue. One of the reasons is due to high resistance, the other reasons can be loose in the connection. This is considered as high risk because it may lead to a short circuit and it could cause severe damage to the transformer itself. On the other hand, PD measurement results are considered to be 37.5% of the total findings of the condition assessment. The majority of these findings have low risk. Besides, there were only 4 transformers have a moderate risk. A remarkable observation that there were no PD activities were considered to be high risk. PD test results can be classified into two categorize based on the location. Most of the PD detection results were found inside the transformer tank. There was no confirmation regarding the PD source which is can be in the bushing, coil or winding. Sometimes the PD source can be due to a particle /impurities that moves during the oil circulation. This can be confirmed during the Dissolve gas analysis and monitor the trends of some of the key gases within the transformer. PD activities also detected inside the transformer cable box. This is can be due to several reasons such as loose in the connection with bushing, bad insulation condition of the cable or it can be due to low insulation of the substance that OETC used in some of the transformers such as oil or compounds. Although there were no major findings are considered as high risk in the PD results, they need to be taken into consideration and need a contingency plan and continuous monitoring until the clearing the defect. The reason behind this action is that most of the transformer fire is generated from the cable box due to PD or corona activities which may develop and their temperature reaches the degree of ignition.

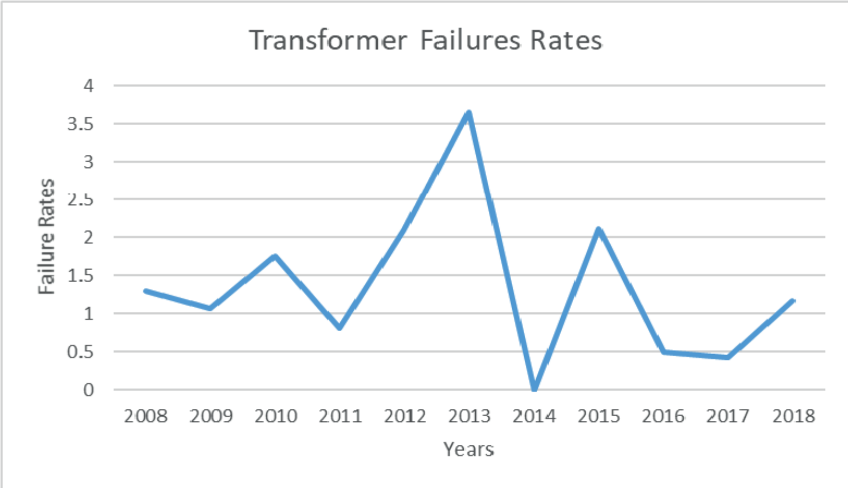

Figure 8: Transformer failure rate

It is essential to study the failure rate of the transformers because that will support the decision making to develop a consistent transformer maintenance strategy. Figure 8 shows the failure rate of the transformer from 2008 to 2018. it is important to mention that the failure in this paper is defined as a failure to deliver the power due to fault or forced outages. During these years, there were only two major failures were recorded in 2009 and 2011 which required a transformer to be replaced. Other than these two, the failures were considered minor such as overloading, mechanical protection malfunction..etc. it is noticed from the figure that the maximum failure reached 3.6 in 2013 and in 2014 there was no failure recorded. However, these records a simple fact which are maintaining the transformer annually is not required.

V. CONCLUSION AND RECOMMENDATION

The in-service condition assessment is an effective tool that can be used to enhance and improve the maintenance strategy. Despite it provides good data about the asset status during operation, offline testing results are essential to building a strong decision about the asset condition. Although there were some observations were considered as high risk, it is considered as individual but not as network risk. Besides, these defects can be cleared within the mentioned plan. The above condition assessment observations that there were some gaps and weaknesses in the maintenance. Furthermore, there are also over or under maintenance frequency in some assets. However, to enhance the maintenance strategy for both Transformers as listed below:

1. Strong need for raising the skill levels for maintenance staff and improve the maintenance process and procedures.
2. Review and improve the current maintenance practice program and procedures against the best practice that suits the OETC network.
3. Retrain maintenance crew and instruct service provider.
4. Enhance the visual inspection of transformers to be every two months.
5. Develop Health and Risk indices for both assets.
6. Develop life cycle replacement.
7. Improve the failure mode of the assets based on the condition assessment which will help to predict when will be the next maintenance/replacement stage.
8. One of the issues that OETC is facing is the overstock of the spare parts. This means that there cost for procurement, storing, auditing, managing and disposing of these spare parts. Building a health and risk indices in line with both failure mode and replacement wave will enhance the spare part management.
9. Enhance the standard specifications and design of the assets.
10. Strengthen the asset register database which will help in both short and long term planning.
11. Increase the general awareness of the risk of improper maintenance.

VI. REFERENCES

[1] Moubray.J., 1992. Reliability Centered Maintenance. 2th. USA: Industrial Press Inc.
[2] Cigre Guid 248 Power Transformer Failure Rate change by age of unit.

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