ACTIVE DETECTION AND IDENTIFICATION OF INCIPIENT FAULTS IN LIQUID FILLED TRANSFORMERS

Emilio Morales Cruz
Senior Member, IEEE
Qualitrol
1385 Fairport Road
Fairport, NY 14450
USA
emorales@qualitrolcorp.com

Radu Udrescu
Member, IEEE
Iris Power LP a Qualitrol Company
3110 American Dr
Mississauga, Ontario L4V 1T2
Canada
rudrescu@qualitrolcorp.com

Abstract – The failure of power transformers is always an area of significant concern because it can result in millions of dollars in costs, interruption of power, and possible environmental and safety impacts. Therefore, it is desirable to detect the existence of abnormal changes in the transformer's internal condition and determine whether the changes could lead to a failure. Active detection and identification of incipient faults is now possible through online monitoring of abnormal changes in some parameters and the use of diagnostic methods. This paper gives an overview of a transformer monitoring system and measured signals for the diagnosis of incipient faults.

Index Terms — Online monitoring, active, detection, identification, incipient faults, failures,

I. INTRODUCTION

Continuous online monitoring of substation assets is becoming an essential feature of electric utility systems, continuous process industries, and capital-intensive industries. The justification for online monitoring is based on the need to increase the availability of substation assets, provide condition assessment and life management (action needed i.e. replace, repair, or refurbish), move from time-based maintenance (preventive) to condition-based maintenance (predictive), or reliability-base maintenance (pro-active), failure cause analysis and improve reliability.

II. ACTIVE DETECTION

A. *Online Monitoring of Power Transformers*

System outages due to failures in transformers have a significant economic impact on the operation of the power grid or performance of the continuous process and capital-intensive industry. Therefore, it is necessary to be able to perform a high-quality condition assessment of transformers. Techniques to diagnose integrity through non-invasive tests can be used to optimize the maintenance effort and ensure maximum availability and reliability. With the increase of the average age of the transformer population, there is a growing need to understand their internal state. For this purpose, online and offline methods and systems have been developed in recent years. Online monitoring can be used continuously during operation of the transformer and thus offers the possibility of timely recording of events that can affect the life of the transformer. The automatic evaluation of the collected data allows early detection of major or catastrophic future failures. In contrast, offline methods require an outage of the transformer and are mainly used during regular inspections or when the transformer has already been identified as having problems.

Since the 1990s online monitoring systems for transformers have been developed to the point that they can assess the condition of all the main parts of the transformer. These techniques cannot prevent the failure of transformers since there are some failures that are instantaneous by nature and not susceptible to early detection, whatever monitoring system is installed, but for those failures that are susceptible to early detection, can prevent costly impacts associated with failures of transformers, by allowing the user to take corrective measures during their operational life.

B. *Comprehensive Transformer Monitoring System*

Traditional monitoring uses the concept of setting thresholds for maximum limits at rated operating conditions. Therefore, abnormal changes of monitored parameters below rated operating conditions may be difficult to detect because the parameter may not change enough to reach the threshold.

A comprehensive monitoring system provides a complete view of the health of the transformer through the monitoring of individual parameters and the creation of simple models to compare expected performance against actual performance. This type of monitoring makes it possible to notify the user if a differential threshold value has been reached at any operating condition. The user can then act according to preset company procedures. An example of this can be the top oil temperature. Let's say top oil temperature alarm threshold is set at 85 °C, with transformer loaded at 80% of maximum nameplate rating and ambient temperature of 20 °C. Under these operating conditions, the top oil temperature might be 63 °C. If there is a cooling system issue where top oil reaches a temperature of 75 °C, a traditional monitoring system would not detect the problem, but a comprehensive monitoring system will compare the temperature calculated by the thermal model against the actual temperature and if the differential threshold value is reached it will activate the alarm and the problem will be detected. Some of these models are based on guides published by standard associations, other models are based on the initial performance of the asset values, in both cases the models are reliable and accurate enough to detect changes of condition and most of them can be calibrated.

A complete monitoring system integrates all relevant major components of the power transformer within a single system. The system may include digital components consisting of the transformer database, algorithms, models, and diagnostic function that are in one intelligent electronic device. The transformer database stores all collected data to allow correlation of the real-time transformer information to the past operating data. The algorithms interpret the data to provide information in a way that permits to assess the transformer and all its components. The models evaluate the performance of the asset and compare to actual performance. The diagnostic functions help users make the right decisions regarding the future operation and maintenance of the power transformer.

C. Failure Statistics

The results of the latest transformer reliability survey [1] is shown if Fig. 1; windings are the major cause of failing substation transformers (47 %), followed by tap changers (23 %), bushings (14 %), and lead exits (6 %). All other major components of transformers play a minor role in failures. Looking into catastrophic failures [2], bushings are the cause in 70 % of the cases. There are other components that cause transformers to fail, but these have a lower risk to cause a catastrophic failure.

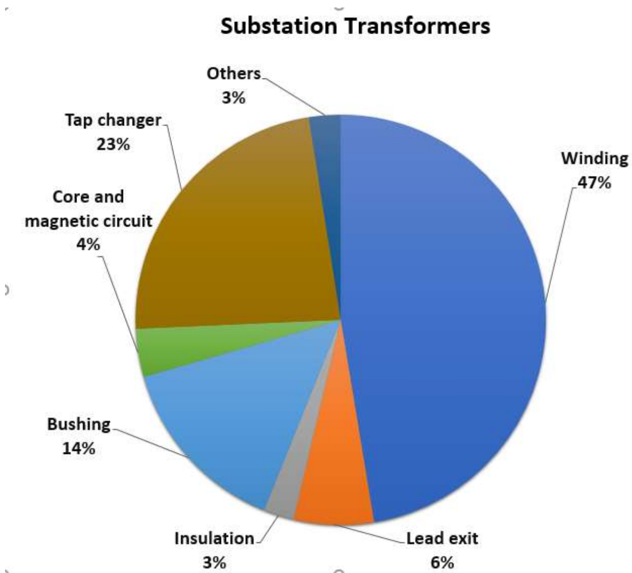

Fig. 1 Latest Substation Transformer Major Failure Statistic

D. Monitored Parameters Overview

Each incipient fault in a transformer will somehow generate detectable signs of its existence. These signs could be chemical, electrical, optical, or acoustic in nature, but most of the time a combination of these. New transformers being manufactured today typically include dozens of analog monitoring devices and several electronic monitoring solutions, as illustrated in Fig. 2. While it may seem overwhelming, present day technology for monitoring of substation power transformers can be narrowed down to nine main types of parameters [3]:

1) *Temperatures:* Besides the conventional temperature sensors, used to measure the top and bottom oil temperature, fiber optic sensors for direct measurement of the hot spot temperatures are now being more frequently used. Together with top oil and bottom oil temperature measurements, they provide a highly accurate thermal model for any transformer. They provide the foundation for calculating the actual dynamic rating for a transformer. Furthermore, they represent one of the bases for aging and moisture models as well as the bubbling temperature model. These measurements are instantaneous and complement DGA and PD.

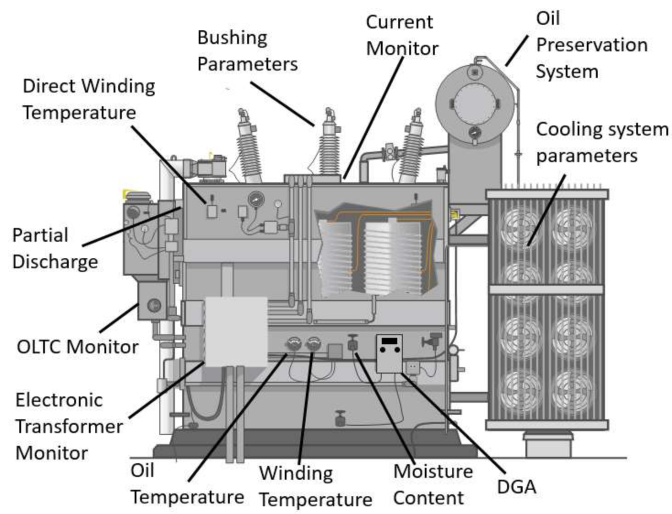

Fig. 2 Monitored Parameters

2) *Dissolved Gas Analysis (DGA):* DGA is the heart of online monitoring as it is a well-established method of transformer diagnosis for timely potential thermal or electrical faults detection, especially in the context of the ageing worldwide transformer fleet. DGA provides a low-cost solution for maximizing transformer life and minimizing unexpected failures.

Hydrogen is used in single gas monitors, since it is present as a result of most faults. It will alert the end user that there is an incipient fault occurring within the transformer that requires attention. However, hydrogen as a single gas does not allow analysis of the fault type. Complete diagnosis of the fault requires analysis of multiple gases. An oil sample can then be drawn and sent to a certified laboratory for complete and comprehensive analysis.

Multi-gas DGA monitors measure multiple dissolved gasses in transformer oil. The measured gas levels can be used to provide an alarm if they reach a user specified concentration and used to diagnose the specific fault that created formation of the gasses. Multi Gas DGA technology is individually sensitive to various gases. These Multi-Gas DGA monitors, either based on Gas Chromatography (GC) or Photo Acoustic Spectroscopy (PAS) technology, provide ppm values of key gases dissolved in transformer oil. GC technology allows automatic field calibration, which is critical for accurate diagnostics and assurance that the monitor is operating properly. The resulting DGA model is now mature after almost two decades of application in the industry, with available guides for limit values and interpretation of gasses generated in oil-immersed transformers [4], silicone-immersed transformers [5], natural ester and synthetic ester-Immersed transformers [6], and in transformer load tap changers [7]. More advanced DGA assessment models are nowadays providing condition assessment based on the combinations and concentrations of the different gases resulting in easier to understand information for the user. The analysis is often delayed by an hour to tens of hours depending on the location of the fault and the insulating liquid flow rate, since they have a direct relation to the amount of time for the combustible gases to be distributed throughout the transformer insulating liquid and reach the sampling port of the transformer tank [4]. The model only identifies the type of fault but does not identify the location of the source of evolving problems. The use of other sensors to confirm and complement this model is the key to comprehensive monitoring.

CIGRE recommends installing hydrogen monitors on healthy transformers and multi-gas monitors on critical or already gassing transformers [8].

3) *Partial Discharges (PD):* One cause of transformer failures is dielectric breakdown of the insulation system, which is often preceded by partial discharge activity. Transformer failures that are thermal or mechanical in nature, are likely to end up resulting in a dielectric fault. The most common causes are deterioration of insulation, manufacturing defects, overloading, through faults, moisture ingress, and loose connections. Although relatively new in transformer application, techniques using ultra-high frequency (UHF) to detect partial discharge have proven accurate and reliable on other electric assets (e.g. gas insulated switchgear, GIS) for three decades. UHF sensors are matched for continuous online monitoring and offer more sensitivity when compared to Acoustic and IEC 60270 PD methods. UHF PD monitoring has been proven to identify evolving problems much earlier than any other monitoring parameter because PD can be detected in real time [9], which makes this parameter ideal for timely detecting incipient faults that evolve quickly and can become major or catastrophic failures if not detected on time. PD pattern recognition using artificial neural networks (ANN) and parameter analysis can be verified by a DGA model to provide excellent confirmation. For transformers with three or more sensors, time of flight method can be used to localize and find the source very accurately. Localization of a PD source is one of the most important pieces of information in order to assess the condition of a transformer, its' evolving effects, comprehensive risk assessment, and to decide if the problem can be fixed on site or if the transformer needs to be replaced. PD monitoring application does not depend of voltage ranges or transformer sizes, it depends mainly on the importance of the transformer in the system to which it is connected to, that is why it normally applies to generator step-up (GSU) and transmission transformers as well as critical transformers in continuous process and capital-intensive industries.

4) *Moisture:* A separate moisture sensor is usually combined with a dissolved gas sensor. Simple reading of moisture in oil is used to create moisture in oil model. By comparing the trends of moisture in oil with actual transformer load, the thermal model, and the use of moisture equilibrium curves for paper-oil system [10], the moisture in insulation can be estimated. Also, its' influence in the acceleration on the cellulose aging rate [11], reduction in dielectric strength, bubble formation, and partial discharges in the insulation can be determined. These models are relatively less accurate when compared to DGA, thermal, and PD models. However, when combined they accurately portray remaining life calculations and actual dynamic rating for a transformer.

5) *Cooling System Parameters:* The operation and efficiency of the cooling system are determined by the measurement of the cooler inlet and outlet temperature. Often it is also enough to use simply the top and bottom oil temperature. In order to detect evolving defects, usually the fan and pump currents and the flow are monitored. Together with the cooling efficiency model, a problem with the cooling system can be detected and the fans and pumps can be controlled accordingly.

6) *Oil Preservation System:* The monitoring of oil levels, conservator tank bladder rupture, condition of regenerating breather and tank internal pressure provide early detection of issues with the oil preservation system. Oil levels together with a thermal model can provide an early indication of an oil leak. A conservator tank bladder rupture relay which detects the presence of air on the oil side of the bladder and a silica regenerating breather activated by relative humidity level can provide an indication of a malfunction in the conservator tank preservation system. An abnormal internal pressure will also indicate a malfunction of sealed, inert gas, or conservator tank preservation systems.

7) *Currents:* Line current sensors provide a parameter that is used as an input for the winding hot spot temperature simulated or calculated methods, thermal model, and to verify load dependency with other parameters. An increase of the excitation current, the current required to produce the required magnetic flux in the core, gives an indication of a change of the magnetic circuit, possibly due to through faults opening the core joints or damaging the core, as well as circulating current between core laminations due to lamination insulation breakdown. Its' measurement can be done continuously when power is monitored in the winding with terminals brought out. Core ground current provides indication of the connection status as well as unintentional core grounds. The monitoring of geomagnetic induced currents (GIC) serves to validate the modeling of GIC flows in transformers as well as to verify dependency with other parameters.

8) *Bushing Parameters:* Accurate power factor and capacitance measurements are possible using the phase shift method. The method compares leakage current with a reference signal from the same phase, which is the key to a reliable bushing condition assessment. Besides drastic changes in terms of partial breakdowns or power factor, the accuracy of this method allows the detection of small power factor changes, even the detection of evolving moisture. Certain analytic and correlation models allow distinguishing between different types of defects. The PD monitoring method, using the bushing as coupling capacitor (IEC 60270 method), is less efficient for bushing condition assessment because it is difficult to distinguish the origin of a discharge (external versus internal) and because of the normally low-level discharges of a bushing compared to other discharge sources.

9) *On Load Tap Changer (OLTC) Parameters:* OLTC failures can be combinations of mechanical, electrical, or thermal

faults. Mechanical faults normally have to do with the OLTC motor drive and include failures of springs, bearings, shafts, motors, and drive mechanisms. Changes in switching time, motor current, and motor torque can provide an early indication of a mechanical problem with the motor drive. Faults that are electrical in nature are associated with the diverter and selector switches. These faults normally reveal as an increase of the OLTC oil temperature due to a change in the contact resistance, thus producing more losses and can be attributed to coking of contacts, excessive contact wear, loose contacts, burning of contacts and/or transition resistors, and insulation problems. Monitoring of the temperature difference between the main tank and OLTC compartment, tap operation count, and tap position can provide a successful condition assessment of OLTC diverter and selector switches.

III. FAULT IDENTIFICATION

A. Diagnostic

Each incipient fault in a transformer will generate detectable signs of its' existence. These signs could be chemical, electrical, optical, or acoustic in nature, but most of the time a combination of these. The active detection of these signs, and their combinations, can lead to identifying the fault. The following are some examples of possible faults and the useable parameters for their early detection:

1) *Overheating of Laminations and/or Core Joints:* This phenomenon may take place if the forces due to a through fault were high enough to displace the upper core yoke. This could result in higher losses at the core joint. The resulting increase in temperature that may or may not be detectable by the top and bottom oil sensors but possibly could be detected by a core hot spot sensor. In addition, there will be also a change in the pattern of combustible gas generation, with more hot metal gases being generated. Depending on the fault severity there could be gas accumulation in the gas accumulation relay that would be expected not to correlate with core ground current, partial discharge, winding hot spot temperature, line currents, and parameters used to monitor the cooling system.

2) *Unintentional Core Ground*. This phenomenon may occur if the magnetic circuit gets grounded in a place other than the intended core ground connection point. This will lead to a circulating current through the transformer tank. This circulating current will be detectable, and depending of the fault severity, could cause a small change in the top and bottom oil temperatures. The combustible gas generation will indicate more likely hot metal gases with presence of cellulose overheating due to the nature of the magnetic circuit insulation system. Depending on the fault severity there could be gas accumulation in the gas accumulation relay, and it would be expected not to have correlation with excitation current, partial discharge, winding hot spot temperature, line currents, and parameters used to monitor the cooling system.

3) *Local Overheating in the Winding*, Winding Leads or Connection Points. This phenomenon may occur if there is a short between conductors of the same turn or different turns, a loose or defective connection, a component subject to circulating current due to the leakage flux, etc. The temperature increase is concentrated on a very small area and therefore does not cause enough change to be detected by winding or oil temperature sensors. However, online DGA will indicate a thermal fault with a temperature potentially increasing to >700 °C. If there is insulation present and a potential differential, it can evolve from a thermal to electrical discharge fault that can generate a sudden pressure change and be detected by a rapid pressure rise relay.

4) *Partial Discharge in Winding Insulation*. This phenomenon may occur if the dielectric withstand capability of the winding insulation system has been exceeded due to possible insulation ageing combined with a through fault or due to moisture contamination. Partial discharges will be detected in real time and the pattern will indicate an insulation defect. The combustible gas generation will indicate partial discharge with presence of cellulose overheating and there may or may not be gas accumulation in the gas accumulation relay. There could be correlation with moisture in the insulation, but there should not be correlation with any of the other parameters measured. As mentioned before, once partial discharges have been detected and identified it is very important to determine the source location to decide if the problem can be fixed or if the transformer must be replaced.

IV. CASE STUDIES AND LEARNINGS

1) *A major electric utility Autotransformer Failure:* In Q1 of 2014, a utility experienced a catastrophic failure of a single phase 765 kV autotransformer [9]. This autotransformer was fully monitored per the utility's standard package, which consisted of bushing health, temperatures, fans, pumps, legacy alarming, eight gas monitors, composite gas monitor, and PD monitor. The PD monitor has six sensors that are used to measure partial discharge through a "window" in the autotransformer wall as shown in Fig. 3. This was the first fully monitored transformer failure in the utility's history. This autotransformer was in service for only a few months. Unfortunately, the utility was not prepared to understand the PD "signature". They also had decided not to send the alarms from the PD monitoring system to the transmission operations team until the normal behavior of PD on these 765 kV single phase units had been learned in order to avoid false alarms in the supervisory control and data acquisition (SCADA) system.

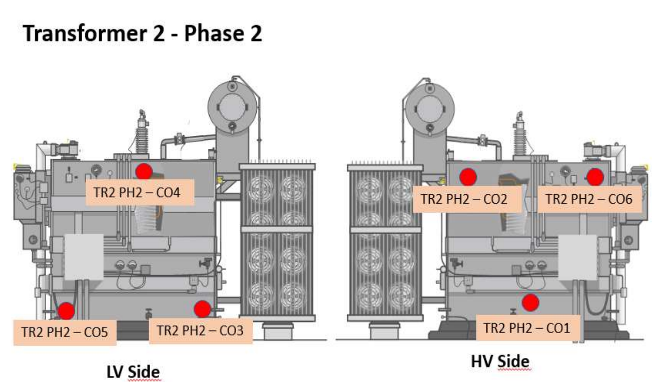

Fig. 3 Monitored Parameters

The transformer failure was rapid and violent. There was no warning from traditional operational alarms, information, or alerts. There was no indication from any monitors except the PD monitoring system, which according to Fig. 4, which shows PD activity over time in hours. The figure shows PD activity 8 hours prior to the failure. This figure shows at the top that the discharge amplitude exceeded 100% of the configured value and at the bottom the discharge rate of 10 or more pulses that are greater than the defined event level, for 60 consecutive cycles. The system also provided the live point on wave (POW) graphic shown in Fig. 5 which displays also the amplitude at the top and discharge rate at the bottom, indicating the point on the AC waveform where discharge occurred for a period of 15 minutes. This figure also provided the PD signature that helps to identify the type of PD failure [12]. Eventually the 8 gas and composite gas monitor would have given an indication but since the autotransformer failed suddenly the gasses did not have enough time to dissolve in the oil.

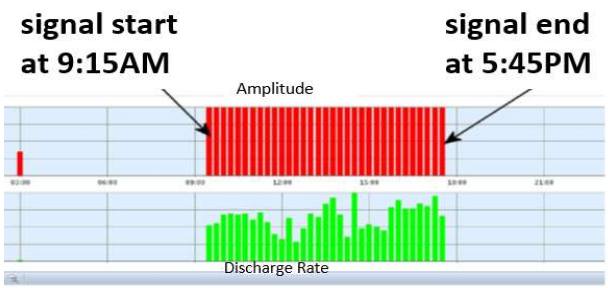

Fig. 4 PD Activity vs. Time

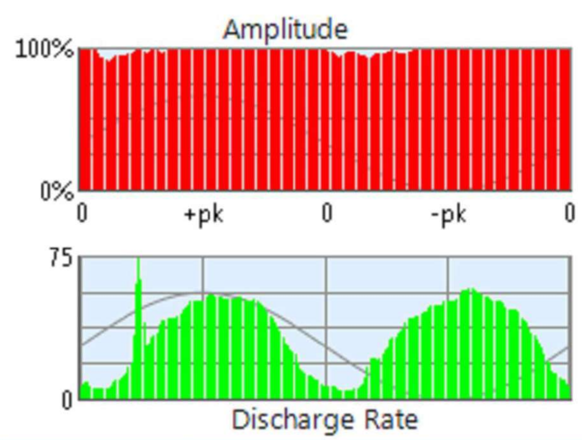

Fig. 5 POW

After this failure, and armed with this new information, new operational procedures were implemented for some autotransformers of the fleet. The new operational procedures are related to PD events, amplitude, and signature detected by the PD monitoring system. If there is a PD alarm at the station, the alarm is triggered to the transmission operations team. This team then ensures that anyone at the station is aware of the alarm. Since safety is the number one concern, while a PD alarm is latched no one is allowed within 75 feet of an autotransformer bank. After everyone is clear, the transmission operations team calls the asset management team for evaluation of the partial discharge. The asset management team works with the transformer specialists and transformer station equipment standards subject matter experts on the next steps and actions. The alarms are then acknowledged, depending on the findings. The utility worked with the vendor of the partial discharge system to determine the best settings to prevent "false" alarms. As a result, since 2015, the utility has reported savings due to the PD monitoring system for preventing failures in the order of $60 million. The utility is now extending the application of PD monitoring systems to their 345 kV and 138 kV fleet.

2) *Online Transformer Monitoring and Lessons Learned From the failure of an Autotransformer:* In Q3 of 2013, an electric utility experienced a failure of a 345/138/13.2 kV, 480 MVA autotransformer [13]. The unit was loaded to about 50% of nameplate during peak conditions. There were no previous issues during factory testing, field testing, or service. On October 24 at 8:33 a.m. a substation maintenance personnel reported an alarm from the multi-gas DGA monitor indicating, among other gasses, 25.6 ppm of acetylene. The DGA monitor readings are shown in Fig. 6. Personnel were dispatched to the site to take a manual oil sample from the autotransformer to be processed using an in-house DGA analyzer. At 1:23 p.m. the DGA was complete and showed no changes in any gas concentrations since its last annual DGA. The utility had recently experienced false alarms from online DGA monitors and therefore personnel believed the DGA monitor to be reporting erroneous fault gas concentrations.

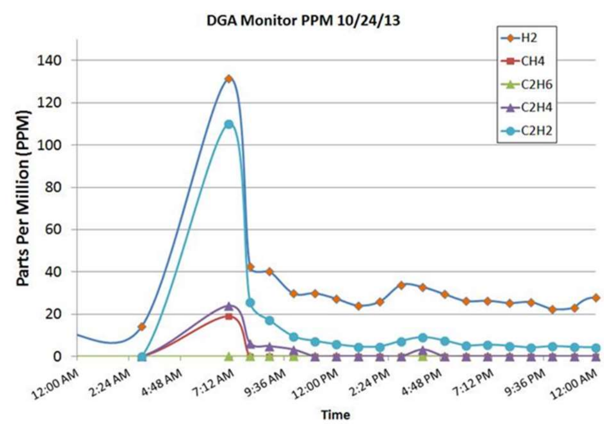

Fig. 6 Gasses Reported by the DGA Monitor

At 2:21 p.m. personnel reported strange temperature readings from the online temperature monitor. It was reporting single-digit temperatures and even negative temperatures intermittently. Temperatures were more than 50 ºC below trip levels (110 ºC top oil and 120 ºC winding), the issue self-corrected within an hour. On October 25 at 1:00 a.m. the autotransformer tripped. The annunciator indicated high top oil and winding temperatures only (no rapid pressure rise (RPR), gas accumulation, current differential, etc.). With support from the temperature monitor OEM, the resistance temperature detector (RTD) was discovered to have failed (resistance fluctuating over time). At 4:00 p.m. trip contacts from the temperature monitor were bypassed and the autotransformer was energized from the low side only. At 4:56 p.m. the autotransformer tripped offline on current differential with operation of RPR relay, gas accumulation, and pressure relief devices. The internal inspection and diagnostic testing determined this to be a phase-to-phase fault had occurred, likely caused by contamination or insulation breakdown. Through an internal inspection a fault was found between phase A and B leads of the regulating winding. The DGA records from the monitor showed that the internal fault initiated and evolved to a major arc (failure) in less than 36 hours. The utility recognized that traditional annual sampling probably would not have caught this and that this incipient fault is the type of condition online monitors are designed to catch. The shortcoming was not technical; the DGA monitor and telecommunications functioned properly during the 36-hour period. Rather, the improvement opportunities were found in the procedures for responding to alarms. There was a bias on the interpretation of DGA alarms, considering recent false alarms from DGA monitors. However, these alarms from two other monitors were due to incorrect oil plumbing that generated false acetylene alarms, which was not an issue at for this monitor. There was also a bias on the interpretation of DGA alarms in context with the temperature monitor alarms. It was considered that a power surge damaged the electronics in both monitors (including the RTD), which was also incorrect. Besides the false alarms experienced from online DGA monitors and no indication of changes in any gas concentration from the validation manual sample, the way the gasses reported by the DGA monitor behaved, a sudden high pick and then reduced values, made the utility conclude that there was an issue with the DGA monitor. Once the actual failure location was identified, it could be seen that it occurred in the immediate vicinity of the DGA monitor inlet while the validation manual sample was taken from the oil drain valve, which was located in the autotransformer end tank wall, as shown in Fig. 7, only about 2 hours after the initial monitor event. It was not until after the second (more severe) fault that the fault gasses were detectable in oil samples taken from the drain valve. Therefore, the validation technique used was not effective for verifying the alarms from the monitor. Considering that fault gasses can take a long time to dissolve in large volumes of oil, the sample should be taken from the monitor line, using a configuration as shown in Fig. 8.

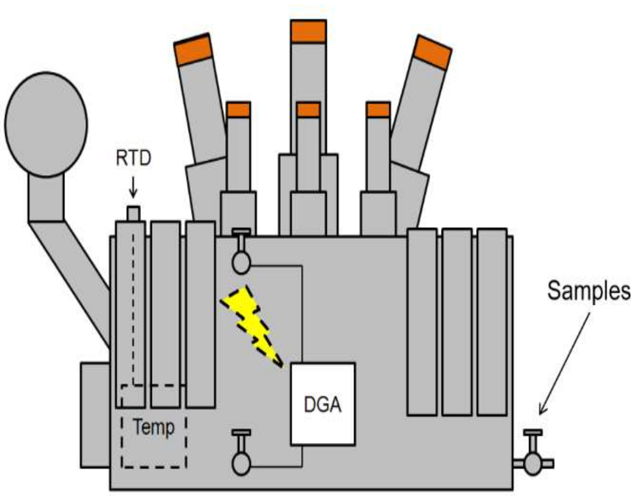

Fig. 7 Fault Location with Respect to the Monitor Inlet

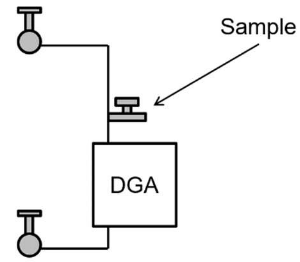

Fig. 8 Monitor Line Sampling Valve

3) *Data from an Eight-gas Online Analyzer Used to Avert Failure of Critical 345 kV Transformer within 2 Years of Installation:* An 1100 MVA GSU power transformer [14] with a remotely accessed DGA monitor was commissioned in November 2003. During the first three months of operation, the unit experienced some generation of combustible gases. An investigation was performed, including thermography studies of the transformer, and the gassing was correlated to the periods when only half of the coolers were running. No generation of gassing was experienced when all the coolers were running. Further troubleshooting identified that one pump was running backwards. On August 28th, 2005 the transformer was fully loaded. During a daily "walk-around" operations personnel noticed an increase in the hydrogen monitor readings from a nominal 55 ppm to about 75 ppm. The system engineers remotely accessed the DGA monitor that continuously monitors and analyzes the transformer gases, which provides results available every four hours, and verified that an event on the afternoon of August 28 had resulted in increasing gas generation. Trending of hot metal gasses (methane, ethane, ethylene, and acetylene) indicated they took an adverse step increase. Monitoring through the night of August 28 validated a sustained increasing gas-generation trend. Results for a subsequent oil sample sent to an independent, off-site laboratory also confirmed the increased gas generation trend.

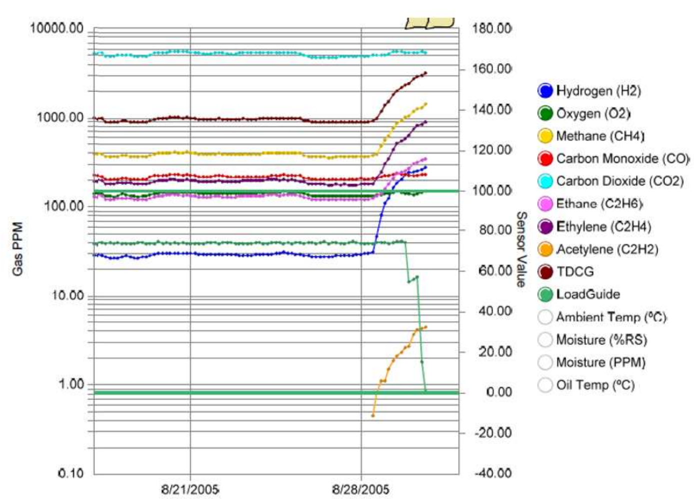

Fig. 9 Individual and total dissolved combustible gases (TDCG) in the Transformer

Fig. 9 shows the rapidly escalating gases in the transformer for 30-day period prior to unit shutdown recorded by the DGA monitor. Fig. 10 shows the rate-of-change (ROC) of methane (>300 ppm/day), ethylene (>200 ppm/day), and a few ppm of acetylene, which indicated a serious and evolving thermal fault > 300 °C based on analysis using the Duval Triangle, shown in Fig. 11.

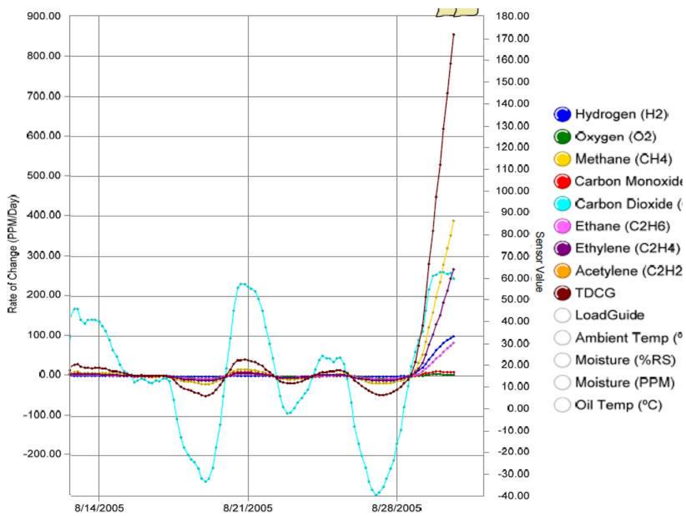

Fig. 10 Individual ROC for individual gases and TDCG

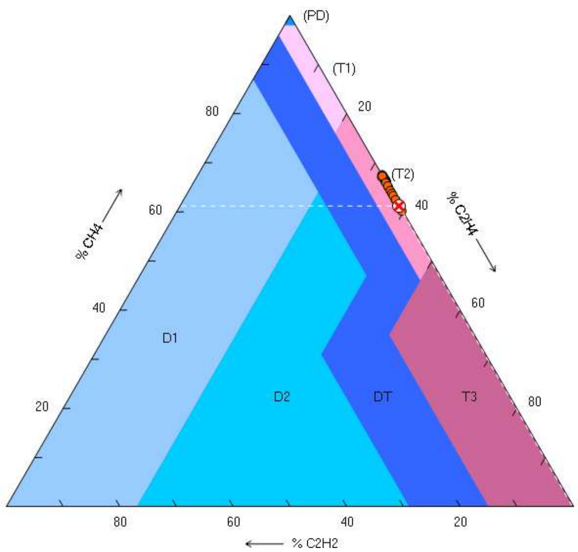

Fig. 11 Duval Triangle Indicating a Thermal Fault >300 C

Load was reduced on the transformer with no change in gassing rates and it was taken offline August 30 to perform an internal inspection, with the intention to also make repairs if possible. Subsequent internal inspection revealed varying degrees of damage in several low voltage (LV) lead cables and discoloration of LV bushing terminations, as shown in Fig.12. As can be seen in Fig. 13, one cable nearly burned through resulting in the severe gassing revealed in August 28. The cable had a crimped connection located on a lead of phase B going from a winding exit to the X2 bushing. A detailed inspection of the damaged connection was performed: Unwrapping of the connection showed dark colored paper and a severely damaged crimped connection (all the contamination was contained by adequately protecting the area while inspecting).

Fig. 12 Discoloration of LV Bushing Terminations

Fig. 13 Cable Nearly Burned Through

The gas generation was found to be due to an overheated crimped connection caused by a combination of high eddy losses in the crimps, poor oil circulation in the high-current insulated crimped bundled-areas and to a lesser extent by an uneven current distribution. Despite obvious burning of paper insulation on the conductor, CO was about 200 ppm prior to August 28 and only increased by 30 ppm. This demonstrates that CO ppm is probably not a reliable indicator of localized paper-damage when diluted within a large volume of oil. Fig. 10 also shows the CO_2 and CO ppm ROC cycling up and down during the 30-day period prior to August 28. This appears to be related to variations in oil temperature (mostly due to ambient temperature and the load) consistent with other online DGA experiences. This would be consistent with experimental results showing CO2 and CO dissolved in the oil are absorbed by the paper insulation as oil temperature decreases and then return to the oil as oil temperature increases [15]). This shows up dramatically through online DGA when old units that have accumulated large quantities of various gases are degassed. CO_2 and CO show a pronounced ppm decrease (absorbed into the insulation) as the transformer cools after being taken offline. CO_2 and CO in the paper are not removed by the degassing process, as are other dissolved gases, and over a period of a month or two slowly return to the oil after the unit is back in service. This is not mentioned in either IEEE or IEC gas guides and there is very little awareness of this behavior in the industry. Only emerging experiences with online DGA brings this out into the open.

V. CONCLUSIONS

The power industry today demands a more comprehensive monitoring approach in order to increase the reliability and availability of electrical assets, allow the application of condition or reliability-based maintenance, detect the existence of abnormal changes in the transformer's internal condition, determine whether the changes could lead to a failure, and improve the asset's use efficiency. Modern monitoring solutions support monitoring of several parameters and include analytic models with diagnostics capabilities, which allow active detection and identification of incipient faults in transformers.

VI. REFERENCES

[1] CIGRE technical Brochure 642, Study Committee A2, WG A2.37. "Transformer Reliability Survey", 2015.

[2] H.-P. Berg, N. Fritze. RELIABILITY OF MAIN TRANSFORMERS. Salzgitter, Germany: Bundesamt für Strahlenschutz, 2011.

[3] IEEE Std C57.143™-2012 "IEEE Guide for Application for Monitoring Equipment to Liquid-Immersed Transformers and Components"

[4] IEEE Std C57.104-2019 "IEEE Guide for the Interpretation of Gases Generated in Mineral Oil-Immersed Transformers

[5] IEEE Std C57.146-2006 "IEEE Guide for the Interpretation of Gases Generated in Silicone-Immersed Transformers

[6] IEEE Std C57.155-2014 "IEEE Guide for the Interpretation of Gases Generated in Natural Ester and Synthetic Ester-Immersed Transformers

[7] IEEE Std C57.139-2015 "IEEE Guide for Dissolved Gas Analysis in Transformer Load Tap Changers

[8] CIGRE Technical Brochure 409, Study Committee D1, WG D1.01 "Report on Gas Monitors for Oil-Filled Electrical Equipment", 2010.

[9] Lessons Learned from Failed Assets at EHV. C. Schneider, K. Phillips, M. Spurlock. TD_D1_S1_P3, COMET 2014.

[10] T. V. Oommen, "Moisture equilibrium in paper-oil insulation systems," in Proc. Electrical/Electronics Insulation Conf., Chicago, IL, 1983.

[11] L. E. Lundgaard, "Aging of oil-impregnated paper in power transformers", IEEE Transactions on Power Delivery, Jan. 2004

[12] CIGRE Technical Brochure 676, Study Committee D1, WG D1.29 "Partial Discharge in Transformers", 2017.

[13] Online Transformer Monitoring and Lessons Learned from the Failure of a 480 MVA Autotransformer. Jimmy Rose, P.E. TD_D1_S1_P1, COMET 2014.

[14] Data from 8-gas online analyzer used to avert failure of critical 345 kV transformer within 2 years of installation. Stan Lindgren, Serveron Corp, Ismael Rivera, Exelon Corp. DistribuTECH – February 4-6, 2007, San Diego, CA

[15] Hisao Kan, Teruo Miyamoto, Proposals for an Improvement in Transformer Diagnosis Using Dissolved Gas Analysis (DGA), IEEE Electrical Insulation Magazine, November/December 1995 – Vol. 11 No. 6.

VII. VITAE

Emilio Morales is a Technical Application Specialist in Transformer applications at Qualitrol Company LLC. His focus is to support solutions in comprehensive monitoring for transformer applications. Emilio previously worked with Efacec Power Transformers, Sunbelt Transformer, Ohio Transformer, and GE-Prolec. He has spent his entire career in design in the power transformer manufacturing industry. He has over 30 years of experience in design, which includes transformers up to 500 MVA and 500 kV as well as furnace and rectifier transformers and different types of reactors. He is a member of the IEEE/PES Transformer Committee, IEC, and CIGRE and actively participates on different task forces. Emilio attended Nuevo Leon State University in Mexico from 1975 to 1979, receiving his Bachelor of Science degree in Electromechanical Engineering in 1980.

Radu Udrescu is an Application Engineer for Iris Power LP, a Qualitrol Company. Radu graduated in Electrical Engineering at Ecole Polytechnique de Montreal, Canada in 2009 and started his career as DGA field service engineer. Currently, Radu works on monitoring solutions for dry type transformers, large motors, and generators. He is a member of IEEE PES and has been involved with transformers and generators for most of his professional life.